EXHIBIT 2

RATE BASE

PUC Distribution Inc • EB-2022-0059 • Filed: August 31,2022

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EXHIBIT 2: RATE BASE

2.1 RATE BASE

The following Exhibit provides details and analysis of the Rate Base for PUC Distribution Inc. ("PUC").

PUC has prepared its Rate Base for the purpose of calculating the revenue requirement in this Application following Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2022 Edition for 2023 Rate Applications issued on April 18, 2022 ("Filing Requirements"). In accordance with the Filing Requirements, PUC has calculated its Rate Base on the average of 2023 Test Year opening and 2023 Test Year closing balances of in-service gross fixed assets and accumulated depreciation, plus a working capital allowance of 7.5%. PUC has not completed a lead-lag study or equivalent analysis to support a different rate and has submitted this application using the default value. PUC's capital expenditures are equivalent to in service additions and the variance analysis is based on these in service additions. The following Table 2-1 compares PUC's 2018 Board Approved Test year to this application's proposed 2023 Test Year.

Table 2-1: 2018 Board Approved vs. Proposed 2023 Test Year

Description	2018 OEB Approved	2023 Test	Variance
Reporting Basis	**MIFRS**	**MIFRS**	
Gross Fixed Assets, Opening Balance	$106,264,141	$161,835,900	$55,571,759
Gross Fixed Assets, Closing Balance	$111,202,318	$171,949,271	$60,746,953
Average Gross Fixed Assets	**$108,733,229**	**$166,892,585**	**$58,159,356**
Accumulated Depreciation, Opening	$13,880,188	$33,923,922	$20,043,734
Accumulated Depreciation, Closing	$17,660,518	$38,997,478	$21,336,960
Average Accumulated Depreciation	**$15,770,353**	**$36,460,700**	**$20,690,347**
Average Net Book Value	**$92,962,876**	**$130,431,885**	**$37,469,009**
Working Capital	$89,269,060	$75,430,690	($13,838,370)
Working Capital Allowance (%)	7.5%	7.5%	0.0%
Working Capital Allowance	**$6,695,180**	**$5,657,302**	**($1,037,878)**
Rate Base	**$99,658,056**	**$136,089,187**	**$36,431,131**

The main components that make up the increase in rate base for the 2023 Test year include capital additions from 2018 to 2022 (which are on track with PUC Distribution's last DSP adjusted as per the OEB approved settlement proposal in EB-2017-0071), Sub-station 16 ("Sub 16") (actual spending is above planned spend at the time of ICM approval in EB-[2019-0170]), Sault Smart Grid ("SSG") (actual spending is on track with ICM approval in EB-[2018-0219/EB-2020-0249]) and 2023 Test Year Capital Additions. A breakdown of each component is provided in Table 2-2.

Table 2-2: Main Component to Change in Rate Base

	2018	2023	Variance
Existing Rate Base	$92,962,875	$73,042,925	($19,919,950)
SSG	$0	$20,757,421	$20,757,421
2018-2022 Capital Additions	$0	$25,902,916	$25,902,916
Sub 16	$0	$5,719,114	$5,719,114
2023 Test Year Additions	$0	$5,009,509	$5,009,509
Working Capital Allowance	$6,695,179	$5,657,303	($1,037,876)
Total	**$99,658,054**	**$136,089,187**	**$36,431,133**

Net fixed assets include those distribution assets that are associated with activities that enable the conveyance of electricity for distribution purposes. Net fixed assets also include Sub 16 assets and SSG assets that will be considered used and useful by December 31, 2022. A further explanation of these assets is included in Section 2.8 below. The rate base calculation excludes any non-distribution assets. Controllable expenses include operations and maintenance, billing and collecting and administration expenses.

PUC has provided its rate base continuity schedule for the years 2018 Board Approved, 2018 Actual, 2019 Actual, 2020 Actual, 2021 Actual, 2022 Bridge and 2023 Test in Table 2-3 below.

Table 2-3: Rate Base Continuity Schedule

Description	2018 OEB Approved	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge	2023 Test
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Gross Fixed Assets, Opening Balance	$106,264,141	$106,264,142	$111,376,076	$116,099,770	$121,327,331	$126,485,748	$161,835,900
Gross Fixed Assets, Closing Balance	$111,202,318	$111,376,076	$116,099,770	$121,327,331	$126,485,748	$161,835,900	$171,949,271
Average Gross Fixed Assets	**$108,733,229**	**$108,820,109**	**$113,737,923**	**$118,713,551**	**$123,906,539**	**$144,160,824**	**$166,892,585**
Accumulated Depreciation, Opening	$13,880,188	$13,880,188	$17,661,743	$21,570,553	$25,599,783	$29,301,780	$33,923,922
Accumulated Depreciation, Closing	$17,660,518	$17,661,743	$21,570,553	$25,599,783	$29,301,780	$33,923,922	$38,997,478
Average Accumulated Depreciation	**$15,770,353**	**$15,770,966**	**$19,616,148**	**$23,585,168**	**$27,450,782**	**$31,612,851**	**$36,460,700**
Average Net Book Value	**$92,962,876**	**$93,049,143**	**$94,121,775**	**$95,128,383**	**$96,455,758**	**$112,547,973**	**$130,431,885**
Working Capital	$89,269,060	$101,087,139	$87,446,944	$95,729,758	$84,363,275	$75,390,085	$75,430,690
Working Capital Allowance (%)	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	**$6,695,180**	**$7,581,535**	**$6,558,521**	**$7,179,732**	**$6,327,246**	**$5,654,256**	**$5,657,302**
Rate Base	**$99,658,056**	**$100,630,679**	**$100,680,296**	**$102,308,115**	**$102,783,004**	**$118,202,229**	**$136,089,187**

PUC's assets fall into two general categories – the first is distribution plant, which includes assets such as distribution substation buildings, poles, conductor, overhead and underground electricity distribution infrastructure, transformers, meters and substation equipment. The second is general plant which includes assets such as the operations/service center building, computer equipment and software and system supervisory equipment.

2.2 FIXED ASSET CONTINUITY STATEMENTS

PUC has completed the Fixed Asset Continuity Schedules (Board Appendix 2-BA) for the Historical Actuals for 2018 through 2021, the 2022 Bridge Year and the 2023 Test Year. PUC had two ICM applications during 2018-2022 where the assets were included in the 1508 regulatory account. For the purposes of presenting Appendix 2-BA PUC has included these additions as part of the 2022 bridge year. Two columns were added to the cost section for 2022 and 2023 to show the gross value of Sub 16 and SSG being included in rate base. Two columns were included in the accumulated depreciation section to show the corresponding depreciation expense and accumulated depreciation for Sub 16 and SSG. These schedules are provided in Appendix A of this Exhibit and have also been filed in live excel format.

The continuity schedules in Appendix A reconcile to the annual recorded depreciation expense. Table 2-4 below reconciles between annual change in accumulated depreciation and depreciation expense.

Table 2-4: Depreciation Continuity Schedule

Depreciation Expense		2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge	2023 Test
Accumulated Depreciation Opening	2105	$13,880,188	$17,661,743	$21,570,553	$25,599,783	$29,301,780	$33,923,922
Accumulated Depreciation Closing	2105	$17,661,743	$21,570,553	$25,599,783	$29,301,780	$33,923,922	$38,997,478
Change in Accumulated Depreciation		($3,781,554)	($3,908,810)	($4,029,231)	($3,701,996)	($4,622,143)	($5,073,556)
Deferred Revenue		($82,576)	($101,862)	($123,987)	($140,229)	($246,348)	($351,857)
Depreciation Expense		$3,864,131	$4,010,672	$4,153,218	$3,842,226	$4,868,490	$5,425,413
Balance		($0)	$0	$0	$0	($0)	($0)

2.2.1 Rate Base Variance Analysis

PUC has prepared Table 2-5 to illustrate the rate base variances for each required comparator. For detailed variance explanations of these, please see Section 2.2.2.

Table 2-5: Rate Base Variance Summary

Description	2018 OEB Approved	2018 Actual	2018 OEB Approved vs 2018 Actual	2019 Actual	2018 Actual vs 2019 Actual	2020 Actual	2019 Actual vs 2020 Actual
Average Gross Fixed Assets	$108,733,229	$108,820,109	$86,880	$113,737,923	$4,917,814	$118,713,551	$4,975,628
Average Accumulated Depreciation	$15,770,353	$15,770,966	$612	$19,616,148	$3,845,182	$23,585,168	$3,969,020
Average Net Book Value	**$92,962,876**	**$93,049,143**	**$86,267**	**$94,121,775**	**$1,072,632**	**$95,128,383**	**$1,006,607**
Working Capital	$89,269,060	$101,087,139	$11,818,079	$87,446,944	($13,640,194)	$95,729,758	$8,282,814
Working Capital Allowance (%)	7.5%	7.5%		7.5%		7.5%	
Working Capital Allowance	**$6,695,180**	**$7,581,535**	**$886,356**	**$6,558,521**	**($1,023,015)**	**$7,179,732**	**$621,211**
Rate Base	**$99,658,056**	**$100,630,679**	**$972,623**	**$100,680,296**	**$49,618**	**$102,308,115**	**$1,627,818**

Description	2021 Actual	2020 Actual vs 2021 Actual	2022 Bridge	2021 Actual vs 2022 Bridge	2023 Test	2022 Bridge vs 2023 Test
Average Gross Fixed Assets	$123,906,539	$5,192,989	$144,160,824	$20,254,284	$166,892,585	$22,731,761
Average Accumulated Depreciation	$27,450,782	$3,865,613	$31,612,851	$4,162,069	$36,460,700	$4,847,849
Average Net Book Value	**$96,455,758**	**$1,327,375**	**$112,547,973**	**$16,092,215**	**$130,431,885**	**$17,883,912**
Working Capital	$84,363,275	($11,366,483)	$75,390,085	($8,973,190)	$75,430,690	$40,605
Working Capital Allowance (%)	7.5%		7.5%		7.5%	
Working Capital Allowance	**$6,327,246**	**($852,486)**	**$5,654,256**	**($672,989)**	**$5,657,302**	**$3,045**
Rate Base	**$102,783,004**	**$474,889**	**$118,202,229**	**$15,419,226**	**$136,089,187**	**$17,886,957**

2.2.2 Variance Analysis On Gross Asset Additions

The following variance analysis has been prepared based on PUC's materiality threshold, per the materiality calculation being noted in Exhibit 1, Section 1.3.14, table 1-17 of this Application. PUC has chosen to use $135,000 as its basis for the variance analysis of Gross Asset Additions.

<u>2018 Board Approved vs. 2018 Actual</u>

PUC is showing an overall increase in gross assets between 2018 Board Approved and 2018 Actual of ($173,758) as can be seen in the following Table 2-6.

1 **Table 2-6: 2018 Board Approved vs. 2018 Actual**

Description		2018 Board Approved	2018 Actual	Variance 2018 Board Approved vs. 2018 Actuals
Reporting Basis		MIFRS	MIFRS	
Distribution Assets				
1706 - Land Rights	1706	$602,307	$602,307	$0
1725 - TX Poles & Fixtures	1725	$1,604,339	$1,604,339	$0
1730 - TX OH Conductors	1730	$63,894	$63,894	($0)
1735 - TX UG Conduit	1735	$870,020	$870,020	$0
1740 - TX UG Conductors	1740	$215,252	$215,252	$0
1805 - Land	1805	$89,160	$56,415	($32,744)
1806 - Land Rights	1806	$0	$0	$0
1612 - Land Rights	1612	$180,572	$189,356	$8,784
1808 - Buildings and Fixtures	1808	$25,090,191	$25,035,547	($54,644)
1810 - Leasehold Improvements	1810	$0	$0	$0
1815 - Transformer Station Equipment - Normally Primary above 50 kV	1815	$7,785,385	$7,954,869	$169,484
1820 - Distribution Station Equipment - Normally Primary below 50 kV	1820	$10,915,612	$10,849,096	($66,516)
1825 - Storage Battery Equipment	1825	$13,722	$13,722	($0)
1830 - Poles, Towers and Fixtures	1830	$19,395,096	$19,552,048	$156,952
1835 - Overhead Conductors and Devices	1835	$13,988,715	$13,939,351	($49,364)
1840 - Underground Conduit	1840	$3,876,689	$4,067,747	$191,058
1845 - Underground Conductors and Devices	1845	$13,799,563	$13,758,378	($41,185)
1850 - Line Transformers	1850	$14,261,914	$13,978,734	($283,179)
1855 - Services	1855	$6,534,115	$6,654,074	$119,959
1860 - Meters	1860	$4,984,603	$4,984,479	($123)
1865 - Other Installations on Customer's Premises	1865	$0	$0	$0
1995 - Contributions and Grants	1995	($11,161,739)	($11,161,739)	($0)
2440 - Deferred Revenue	2440	($3,537,531)	($3,518,564)	$18,967
Sub-Total Distribution Assets		**$109,571,879**	**$109,709,327**	**$137,449**
General Plant				
1980 - System Supervisory Equipment	1980	$1,630,439	$1,666,749	$36,310
1985 - Sentinel Lighting Rentals	1985	$0	$0	$0
1990 - Other Tangible Property	1990	$0	$0	$0
Sub-Total General Plant		**$1,630,439**	**$1,666,749**	**$36,310**
GROSS ASSET TOTAL		**$111,202,318**	**$111,376,076**	**$173,758**

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The following summarizes the major components of the $173,758 variance between the 2018 Board Approved and 2018 Actual Gross Assets.

ACCOUNT 1815 Transformer Station Equipment $169,484

- Transfer trip from Hydro One for line fault.

ACCOUNT 1830 Poles, Towers and Fixtures $156,952

- New services and subdivisions were lower than approved.
- Joint use projects were higher than approved as a result of the timing of the project.
- City projects were higher than approved as a result of the timing of the pole changes on the Black Road project.
- Restricted wire program was lower than approved as less work than plan occurred (Red Pine Drive, Wallace Terrace, Carpin Beach Road).
- Voltage Conversion Program was lower than approved.

ACCOUNT 1840 Underground Conduit $191,058

- New services were lower than approved.
- City projects on Black Road were delayed.
- Voltage conversion costs for Laronde Avenue were higher than approved.

ACCOUNT 1850 Line Transformers ($283,179)

- New services and subdivisions were lower than approved.
- Restricted wire program was lower than approved as less work than plan occurred (Red Pine Drive, Wallace Terrace).

- Forced overhead and underground renewals (due to storm damage, traffic accidents, equipment failures, etc.) were lower than approved.

2018 Actual vs. 2019 Actual

PUC experienced an overall increase in gross assets between 2018 Actual and 2019 Actual of $4,723,694 as can be seen in Table 2-7.

Table 2-7: 2018 Actual vs. 2019 Actual

Description		2018 Actual	2019 Actual	Variance 2018 Actuals Vs. 2019 Actuals
Reporting Basis		MIFRS	MIFRS	
Distribution Assets				
1706 - Land Rights	1706	$602,307	$602,307	$0
1725 - TX Poles & Fixtures	1725	$1,604,339	$1,604,339	$0
1730 - TX OH Conductors	1730	$63,894	$63,894	$0
1735 - TX UG Conduit	1735	$870,020	$870,020	$0
1740 - TX UG Conductors	1740	$215,252	$215,252	$0
1805 - Land	1805	$56,415	$56,415	$0
1806 - Land Rights	1806	$0	$0	$0
1612 - Land Rights	1612	$189,356	$203,667	$14,311
1808 - Buildings and Fixtures	1808	$25,035,547	$25,213,351	$177,803
1810 - Leasehold Improvements	1810	$0	$0	$0
1815 - Transformer Station Equipment - Normally Primary above 50 kV	1815	$7,954,869	$8,188,818	$233,949
1820 - Distribution Station Equipment - Normally Primary below 50 kV	1820	$10,849,096	$11,075,369	$226,273
1825 - Storage Battery Equipment	1825	$13,722	$13,722	$0
1830 - Poles, Towers and Fixtures	1830	$19,552,048	$21,610,992	$2,058,945
1835 - Overhead Conductors and Devices	1835	$13,939,351	$14,585,893	$646,542
1840 - Underground Conduit	1840	$4,067,747	$4,562,660	$494,913
1845 - Underground Conductors and Devices	1845	$13,758,378	$14,072,856	$314,478
1850 - Line Transformers	1850	$13,978,734	$14,877,136	$898,402
1855 - Services	1855	$6,654,074	$7,190,881	$536,808
1860 - Meters	1860	$4,984,479	$5,061,095	$76,616
1865 - Other Installations on Customer's Premises	1865	$0	$0	$0
1995 - Contributions and Grants	1995	($11,161,739)	($11,161,739)	$0
2440 - Deferred Revenue	2440	($3,518,564)	($4,630,407)	($1,111,843)
Sub-Total Distribution Assets		**$109,709,327**	**$114,276,524**	**$4,567,197**
General Plant				
1980 - System Supervisory Equipment	1980	$1,666,749	$1,823,246	$156,497
1985 - Sentinel Lighting Rentals	1985	$0	$0	$0
1990 - Other Tangible Property	1990	$0	$0	$0
Sub-Total General Plant		**$1,666,749**	**$1,823,246**	**$156,497**
GROSS ASSET TOTAL		**$111,376,076**	**$116,099,770**	**$4,723,694**

The following summarizes the major components of the $4,723,694 variance between 2018 Actual and 2019 Actual Gross Assets.

ACCOUNT 1808 Building & Fixtures $177,803

- LED lighting upgrades.
- HVAC upgrades.

ACCOUNT 1815 Transformer Station Equipment $233,949

- Insulator replacements at transmission stations 1 and 2 - $207,572.
- Various other immaterial items - $26,377.

ACCOUNT 1820 Distribution Station Equipment $226,273

- Sub 1 - $40,948
    - DC system upgrade
- Sub 11 - $39,690
    - DC system upgrade
- Sub 12 - $48,370
    - DC system upgrade
- Sub 15 - $20,282
    - Battery bank replacement
- Sub 18 - $23,893
    - UFLS anti-stall stage
- Sub 19 - $10,913
    - UFLS anti-stall stage

- Forced Station Renewal - $42,177 – Battery bank replacements/additions, SCADA and communication equipment renewal, breaker upgrades, relay upgrades and RTU upgrades.

ACCOUNT 1830 Poles, Towers and Fixtures $2,058,945

- New services and subdivisions - $93,415 – Service to new Ruth Street and Johnson Avenue semis, Fifth Line, Chapple Avenue, Kohler Street, Great Northern Rd (2), Dundas Street, Wellington Street West, Sunnyside Beach Road, East Belfour Street, Second Line East and West, Spruce Street, Base Line and Old Garden River Road.
- Overhead renewal program - $551,452 - Replace deteriorated poles at various locations as required.
- Road Construction Projects - $189,283 – Replace deteriorated poles in conjunction with City Road projects. Areas completed include McNabb Street, Bay Street and Black Road.
- Forced Overhead renewal (renewal due to storm damage, traffic accidents, etc.) - $206,312 – Traffic accidents on East Street, Trunk Road, Queensgate Boulevard, McDonald Avenue, Queen Street, Goulais Avenue, Hugill Street, and unplanned miscellaneous capital replacements.
- Restricted wire program - $129,027 – Welcome Avenue, Red Pine Drive and Second Avenue.
- Voltage Conversion Program - $257,181 – McDonald Avenue, Pine Street, Elizabeth Street and Chapple Avenue.
- Bell Fibre Project - $613,390 – Replaced joint use poles in conjunction with Bell as a result of a city-wide Fibre project.

ACCOUNT 1835 Overhead Conductors and Devices $646,542

- New services and subdivisions - $73,887 - Service to Queen Street East, Second Line East and West, McNabb Street, Wellington Street West, Spruce Street, Sunnyside Beach Road, Old Garden River Road and Drive In Road.
- Overhead renewal program - $48,409 - Replaced overhead conductor and devices at miscellaneous locations.
- Road Construction Projects - $64,954 – Replace overhead conductor and devices in conjunction with the City road projects.
- Restricted wire program - $171,848 – Welcome Avenue, Red Pine Drive, Cumberland Avenue and Woodcroft Street.
- Voltage Conversion Program - $211,725 - McDonald Avenue, Pine Street, Elizabeth Street and Moluch Street.
- Bell Fibre Project - $75,719 – Replaced overhead devices in conjunction with Bell as a result of a city-wide Fibre project.

ACCOUNT 1840 Underground Conduit $494,913

- New services and subdivisions - $31,396 – Work at Greenfield subdivision and miscellaneous service requests.
- Underground renewal program - $121,218 – Vault replacements, Pad-mount Switch Gear Replacement, and miscellaneous unplanned capital replacements.
- Voltage Conversion Program - $299,037 – Breton Road and Laronde Avenue.
- Various other immaterial items - $43,262

ACCOUNT 1845 Underground Conductors and Devices $314,478

- New services and subdivisions - $236,249 – Work at Greenfield subdivision, Queen Street East, Second Line East and West, McNabb Street, Trunk Road, Huron Street, Base Line, and miscellaneous service requests.
- Underground renewal program - $35,352 – Vault replacements, Pad-mount Switch Gear Replacement, and miscellaneous unplanned capital replacements.
- Voltage Conversion Program - $42,877 - McDonald Avenue, Laronde Avenue and Breton Road.

ACCOUNT 1850 Line Transformers $898,402

- New services and subdivisions - $422,547 – Service to Greenfield subdivision, Second Line East, Drive-in Road, McNabb Street, Old Garden River Road, Queen Street, Huron Street, Base Line, Wellington Street West, Fifth Line, Chapple Avenue, Kohler Street, Great Northern Rd, Dundas Street, Wellington Street West, and various residential services.
- Overhead renewal program - $99,823 – Replace transformers on Spruce Street, Heath Road, Creek Road, Chippewa Street, Old Garden River Road, Cathcart Street, Willoughby Street, and miscellaneous unplanned capital replacement.
- Underground renewal program - $194,118 – Replace leaking transformer on Breton Road, Second Line West, Great Northern Road, Bristol Place, Lake Street, and miscellaneous unplanned replacements.
- Restricted wire program - $63,763 – Second Avenue, Welcome Avenue, Cumberland Avenue and Red Pine Drive.
- Voltage Conversion Program - $118,151 – Breton Street, Pine Street, Muloch Street, Elizabeth Street and MacDonald Avenue.

ACCOUNT 1855 Services - $536,808

- New services and subdivisions - $383,801 – Customer Demand residential services and Customer Demand commercial services. Service to Canal Drive, Second Line East, Sunnyside Beach Road, and various commercial and residential services.
- Road Construction Projects - $96,749 – McNabb Street construction project.
- Restricted wire program - $41,688 – Red Pine Drive.
- Various other immaterial items - $14,570

ACCOUNT 1860 Smart Meters $76,616

- Meter installations - $67,598 – Install new electric meters.
- Various other immaterial items – $9,018.

ACCOUNT 1980 System Supervisor Equipment $156,947

- DS breaker replacement – $75,816.
- RTU replacements - $29,704.
- Recloser radio upgrades - $20,729.
- Speednet repeater – $14,288.
- Various other immaterial items - $16,410.

ACCOUNT 2440 Deferred Revenue ($1,111,843)

- New services and subdivisions.
- Motor vehicle accident damage recovery.
- Bell fibre joint use project.

<u>2019 Actual vs. 2020 Actual</u>

PUC experienced an overall increase in gross assets between 2019 Actual and 2020 Actual of $5,227,561, as can be seen in the following Table 2-8.

Table 2-8: 2019 Actual vs. 2020 Actual

Description		2019 Actual	2020 Actual	Variance 2019 Actuals Vs. 2020 Actuals
Reporting Basis		**MIFRS**	**MIFRS**	
Distribution Assets				
1706 - Land Rights	1706	$602,307	$602,307	$0
1725 - TX Poles & Fixtures	1725	$1,604,339	$1,604,339	$0
1730 - TX OH Conductors	1730	$63,894	$63,894	$0
1735 - TX UG Conduit	1735	$870,020	$870,020	$0
1740 - TX UG Conductors	1740	$215,252	$215,252	$0
1805 - Land	1805	$56,415	$56,415	$0
1806 - Land Rights	1806	$0	$0	$0
1612 - Land Rights	1612	$203,667	$217,935	$14,268
1808 - Buildings and Fixtures	1808	$25,213,351	$25,339,070	$125,719
1810 - Leasehold Improvements	1810	$0	$0	$0
1815 - Transformer Station Equipment - Normally Primary above 50 kV	1815	$8,188,818	$8,373,668	$184,850
1820 - Distribution Station Equipment - Normally Primary below 50 kV	1820	$11,075,369	$11,606,662	$531,294
1825 - Storage Battery Equipment	1825	$13,722	$13,722	$0
1830 - Poles, Towers and Fixtures	1830	$21,610,992	$23,408,492	$1,797,499
1835 - Overhead Conductors and Devices	1835	$14,585,893	$15,369,046	$783,153
1840 - Underground Conduit	1840	$4,562,660	$4,624,916	$62,255
1845 - Underground Conductors and Devices	1845	$14,072,856	$14,627,297	$554,440
1850 - Line Transformers	1850	$14,877,136	$15,830,744	$953,608
1855 - Services	1855	$7,190,881	$7,583,283	$392,402
1860 - Meters	1860	$5,061,095	$5,537,398	$476,303
1865 - Other Installations on Customer's Premises	1865	$0	$0	$0
1995 - Contributions and Grants	1995	($11,161,739)	($11,161,739)	$0
2440 - Deferred Revenue	2440	($4,630,407)	($5,288,573)	($658,166)
Sub-Total Distribution Assets		**$114,276,524**	**$119,494,150**	**$5,217,626**
General Plant				
1980 - System Supervisory Equipment	1980	$1,823,246	$1,833,182	$9,935
1985 - Sentinel Lighting Rentals	1985	$0	$0	$0
1990 - Other Tangible Property	1990	$0	$0	$0
Sub-Total General Plant		**$1,823,246**	**$1,833,182**	**$9,935**
GROSS ASSET TOTAL		**$116,099,770**	**$121,327,331**	**$5,227,561**

The following summarizes the major components of the $5,227,561 variance between 2019 Actual and 2020 Actual Gross Assets.

ACCOUNT 1815 Transformer Station Equipment $184,850

- Transmission station upgrades - $107,047 – 115kV Upgrade.
- Various other immaterial items - $77,803.

ACCOUNT 1820 Distribution Station Equipment $531,294

- Sub 1 - $27,502
  - DC system upgrade
- Sub 10 - $42,143
  - Battery replacement
- Sub 11 - $30,516
  - DC system upgrade
- Sub 12 - $27,547
  - Station service
- Sub 18 - $58,285
  - DC system upgrade
- Relay upgrades at substations 1, 11 and 20 - $240,166.
- Forced Station Renewal- $72,729- Battery bank replacements/additions, SCADA and communication equipment renewal, breaker upgrades, relay upgrades, RTU upgrades.
- Various other immaterial items - $32,406.

ACCOUNT 1830 Poles, Towers and Fixtures $1,797,499

- New services and subdivisions - $202,752 – Service to new Ruth St and Johnson Avenue semis, Fifth Line, Chapple Avenue, Kohler Street, Great Northern Rd (2), Dundas Street, Wellington Street West, Sunnyside Beach Road, Second Line West, Brule Road, Chambers Avenue, Eagle Drive, and Wilderness Court.
- Overhead renewal program - $487,228 - Replace deteriorated poles at various locations as required, replaced poles at Willoughby Road, Sackville Road, Boundary Road, Willow Avenue, River Road, Cathcart Street and other miscellaneous locations.
- Road Construction Projects - $105,558 – Replace deteriorated poles in conjunction with City Road projects. Areas completed include Bay Street and Black Road.
- Forced Overhead renewal (renewal due to storm damage, traffic accidents, etc.) - $247,202 – Traffic accidents on Bay Street, Reid Street, Second Line West, Goulais Avenue, Boundary Road, Queen Street East, Albert Street, Northern Avenue Third Avenue, Lake Street, and unplanned miscellaneous capital replacements.
- Restricted wire program - $257,161 – Case Road, Chippewa Street and Moss Road.
- Voltage Conversion Program - $116,782 – McDonald Avenue, Forest Avenue and Shannon Road.
- Bell Fibre Project - $380,817 – Replaced joint use poles in conjunction with Bell as a result of a city-wide Fibre project.

ACCOUNT 1835 Overhead Conductors and Devices $783,153

- New services and subdivisions - $95,399 - Service to Industrial Park Court, Great Northern Road, Fifth Line, Chapple Avenue, Third Line East, Dundas Avenue, Maki Road, Case Road, Millcreek Drive.

- Overhead renewal program - $167,371 - Replaced overhead conductor and devices on Willoughby Road, Sackville Road, Boundary Road, Willow Avenue, Cathcart Street and other miscellaneous locations.
- Restricted wire program - $237,475 – Case Road, Chippewa Street, Korah Road, and Moss Road.
- Voltage Conversion Program - $137,377 - McDonald Avenue, Forest Avenue and Shannon Road.
- Bell Fibre Project - $117,447 – Replaced overhead devices in conjunction with Bell as a result of a city-wide Fibre project.
- Various other immaterial items - $28,084.

ACCOUNT 1845 Underground Conductors and Devices $554,440

- New services and subdivisions - $118,087 – Work at Canal Drive, Great Northern Road, Chapple Avenue, Wellington Street West, Kohler Street and Allen Side Road, and miscellaneous service requests.
- Underground renewal program - $393,462 – Vault replacements, Pad-mount Switch Gear Replacement, and miscellaneous unplanned capital replacements.
- Voltage Conversion Program - $31,105 - McDonald Avenue and Breton Road.
- Various other immaterial items - $11,786.

ACCOUNT 1850 Line Transformers $953,608

- New services and subdivisions - $317,429 – Service to new Ruth St and Johnson Avenue semis, Fifth Line, Chapple Avenue, Kohler Street, Great Northern Rd, Dundas Street, Wellington Street West, Gran Street, Fifth Line East, Industrial Park Crescent, Sunnyside Beach Drive, Wilderness Court, and Canal Drive, and various residential services.

- Overhead renewal program - $111,183 – Replace transformers on Canal Drive, Bay Street, Creek Road, Chippewa Street, Old Garden River Road, Cathcart Street, Willoughby Street, and miscellaneous unplanned capital replacement.
- Underground renewal program - $61,253 – Replace leaking transformer on Breton Road, Lake Street, and miscellaneous unplanned replacements.
- Restricted wire program - $125,458 - Case Road, Chippewa Street, and Moss Road.
- Voltage Conversion Program - $39,918 - Breton Street, Forest Avenue and Shannon Road.
- Transformer critical inventory - $241,877 – Increase in transformer critical inventory level due to longer lead times.
- Various other immaterial items - $61,490.

ACCOUNT 1855 Services $392,402

- New services and subdivisions - $372,591 – Customer Demand residential services and Customer Demand commercial services. Service to Fifth Line, Chapple Avenue, Kohler Street, Great Northern Rd, Dundas Street, Wellington Street West, Trunk Road, Pim Street, Sunnyside Beach Drive, and various residential services.
- Various other immaterial items - $19,811.

ACCOUNT 1860 Meters $476,303

- Meter installations - $467,799 – Install new electric meters.
- Various other immaterial items – $8,504.

ACCOUNT 2440 Deferred Revenue ($658,166)

- New services and subdivisions.
- Motor vehicle accident damage recovery.
- Bell fibre joint use project.

2020 Actual vs. 2021 Actual

PUC experienced an overall increase in gross assets between 2020 Actual and 2021 Actual of $5,158,417 as can be seen in the following Table 2-9.

Table 2-9: 2020 Actual vs. 2021 Actual

Description		2020 Actual	2021 Actual	Variance 2020 Actuals Vs. 2021 Actuals
Reporting Basis		**MIFRS**	**MIFRS**	
Distribution Assets				
1706 - Land Rights	1706	$602,307	$602,307	$0
1725 - TX Poles & Fixtures	1725	$1,604,339	$1,604,339	$0
1730 - TX OH Conductors	1730	$63,894	$63,894	$0
1735 - TX UG Conduit	1735	$870,020	$870,020	$0
1740 - TX UG Conductors	1740	$215,252	$215,252	$0
1805 - Land	1805	$56,415	$56,415	$0
1806 - Land Rights	1806	$0	$0	$0
1612 - Land Rights	1612	$217,935	$375,398	$157,463
1808 - Buildings and Fixtures	1808	$25,339,070	$25,923,775	$584,705
1810 - Leasehold Improvements	1810	$0	$0	$0
1815 - Transformer Station Equipment - Normally Primary above 50 kV	1815	$8,373,668	$8,444,496	$70,828
1820 - Distribution Station Equipment - Normally Primary below 50 kV	1820	$11,606,662	$12,181,995	$575,333
1825 - Storage Battery Equipment	1825	$13,722	$13,722	$0
1830 - Poles, Towers and Fixtures	1830	$23,408,492	$24,983,155	$1,574,663
1835 - Overhead Conductors and Devices	1835	$15,369,046	$15,876,144	$507,099
1840 - Underground Conduit	1840	$4,624,916	$4,808,197	$183,281
1845 - Underground Conductors and Devices	1845	$14,627,297	$15,191,109	$563,813
1850 - Line Transformers	1850	$15,830,744	$16,603,673	$772,929
1855 - Services	1855	$7,583,283	$8,176,278	$592,995
1860 - Meters	1860	$5,537,398	$5,753,920	$216,522
1865 - Other Installations on Customer's Premises	1865	$0	$0	$0
1995 - Contributions and Grants	1995	($11,161,739)	($11,161,739)	$0
2440 - Deferred Revenue	2440	($5,288,573)	($5,929,786)	($641,214)
Sub-Total Distribution Assets		**$119,494,150**	**$124,652,566**	**$5,158,417**
General Plant				
1980 - System Supervisory Equipment	1980	$1,833,182	$1,833,182	$0
1985 - Sentinel Lighting Rentals	1985	$0	$0	$0
1990 - Other Tangible Property	1990	$0	$0	$0
Sub-Total General Plant		**$1,833,182**	**$1,833,182**	**$0**
GROSS ASSET TOTAL		**$121,327,331**	**$126,485,748**	**$5,158,417**

The following summarizes the major components of the $5,158,417 variance between 2020 Actual and 2021 Actual Gross Assets.

ACCOUNT 1808 Buildings and Fixtures $584,705

- Replace garage doors $567,194.
- HVAC additions $21,659.

ACCOUNT 1820 Distribution Station Equipment $575,333

- Sub 1 - $7,898
  - Station service
- Sub 11 - $20,322
  - Circuit replacement
- Sub 12 - $23,828
  - Station service
- Sub 18 - $49,783
  - DC system upgrade
- Sub 20 - $15,304
  - Power transformer and fuse replacement
- Relay upgrades at substations 1, 11 and 20 - $394,092.
- Various other immaterial items - $64,915.

ACCOUNT 1830 Poles, Towers and Fixtures $1,574,663

- New services and subdivisions - $235,445 – Service to Third Line West at Isabel Fletcher School, Truck Road Starbucks, Gran St, White Oak Drive West, Great Northern Rd, Northwood Street, Airport Road, Townline Road, Sunnyside Beach Road, Second

Line West, Maki Road, Ironside Drive, Lakeshore Drive, Allens Side Road, Pineshores Drive.

- Overhead renewal program - $400,090 - Replace deteriorated poles at various locations as required, replaced poles at Goulais Avenue, Bush/Bryne Streets, Old Garden River Road, Royal York Boulevard, Third Line East and Greenfield Drive.
- Road Construction Projects - $159,045 – Replace deteriorated poles in conjunction with City Road projects. Areas completed include Bay Street, Sixth Avenue and Third Line East.
- Forced Overhead renewal (renewal due to storm damage, traffic accidents, etc.) - $301,275 – Traffic accidents on Boundary Road, Second Line West, Black Road (2), Queen St East, Fourth Line East, Sixth Line East, and Albert Street, as well as unplanned miscellaneous capital replacements.
- Restricted wire program - $133,097 – Grand area and Lennox/Bainbridge Streets.
- Voltage Conversion Program - $303,860 – Leo/McGregor Streets and Forest Avenue.
- Various other immaterial items - $41,851.

ACCOUNT 1835 Overhead Conductors and Devices $507,099

- New services and subdivisions - $66,428 - Service to Industrial Park Court, Truck Road, Third Line West, Brule Road, Old Goulais Bay Road, Maki Road, Nokomis Beach Road.
- Overhead renewal program - $73,579 - Replaced overhead conductor and devices on Goulais Ave, Bush Street, Queen Street East.
- Forced Overhead renewal (renewal due to storm damage, traffic accidents, etc.) - $44,999 - Traffic accidents on Second Line (2) and miscellaneous unplanned capital replacements.
- Restricted wire program - $69,215 – Grand area and Lennox/Bainbridge Streets.

- Voltage Conversion Program - $240,008 - Leo/McGregor/Lake Streets and Forest Avenue.
- Various other immaterial items - $12,870.

ACCOUNT 1840 Underground Conduit $183,281

- New services and subdivisions - $134,377 – Greenfield subdivision, Denwood subdivision, Eastside subdivision, Castle Heights subdivision and miscellaneous service requests.
- Underground renewal program - $48,904 – Louise Ave replacement and miscellaneous unplanned additions.

ACCOUNT 1845 Underground Conductors and Devices $563,813

- New services and subdivisions - $349,444 – Greenfield subdivision, Denwood subdivision, Eastside subdivision, Castle Heights subdivision, Crestwood subdivision, and miscellaneous service requests.
- Underground renewal program - $183,440 – Vault replacements and miscellaneous unplanned capital replacements.
- Various other immaterial items - $30,929.

ACCOUNT 1850 Line Transformers $772,929

- New services and subdivisions - $329,702 – Greenfield subdivision, Denwood subdivision, Eastside subdivision, Isabel Fletcher School service, Donna Drive townhouses, White Oak Drive multi unit development, Industrial Park Crescent service, Great Northern Road service (3), Gran St service, and various residential services.

- Overhead renewal program - $111,183 – Replace transformers on Trunk Rd, Douglas Street, Bristol Place, Peoples Road, Sackville Road, Willowdale Street, and miscellaneous unplanned capital replacement.
- Underground renewal program - $214,357 – Replace leaking transformer on Bay Street, Canal Drive, Madison Avenue, Second Line West and miscellaneous unplanned replacements.
- Restricted wire program - $19,414 - Grand area and Lennox/Bainbridge Streets.
- Voltage Conversion Program - $89,494 - Leo/McGregor/Lake Streets and Forest Avenue.
- Various other immaterial items - $8,779.

ACCOUNT 1855 Services $592,995

- New services and subdivisions - $588,920 – Customer Demand residential services and Customer Demand commercial services.
- Various other immaterial items - $4,075.

ACCOUNT 1860 Meters $216,522

- Meter installations - $208,055 – Install new electric meters.
- Various other immaterial items – $8,467.

ACCOUNT 2440 Deferred Revenue ($641,214)

- New services and subdivisions.
- Motor vehicle accident damage recovery.

<u>2021 Actual vs. 2022 Bridge</u>

PUC's overall increase in Gross Assets between 2021 Actual and 2022 Bridge is $35,350,152, as can be seen in the following Table 2-10. The primary driver of the increase is the inclusion of actual spending on Sub 16 and the SSG project. Sub 16 was approved as part of PUC's 2019 ICM application (EB-2019-0170). The SSG project was approved as part of PUC's 2022 ICM application (EB-2018-0219/EB-2020-0249). These two projects including reconciliation of proposed vs. actual spend, and revenue requirements are shown in Section 2.8 below.

1
Table 2-10: 2021 Actual vs. 2022 Bridge

Description		2021 Actual	2022 Bridge	Variance 2021 Actuals Vs. 2022 Bridge
Reporting Basis		**MIFRS**	**MIFRS**	
Distribution Assets				
1706 - Land Rights	1706	$602,307	$602,307	$0
1725 - TX Poles & Fixtures	1725	$1,604,339	$1,604,339	($0)
1730 - TX OH Conductors	1730	$63,894	$63,894	$0
1735 - TX UG Conduit	1735	$870,020	$870,020	$0
1740 - TX UG Conductors	1740	$215,252	$215,252	$0
1805 - Land	1805	$56,415	$56,415	$0
1806 - Land Rights	1806	$0	$0	$0
1612 - Land Rights	1612	$375,398	$375,398	$0
1808 - Buildings and Fixtures	1808	$25,923,775	$25,959,603	$35,828
1810 - Leasehold Improvements	1810	$0	$0	$0
1815 - Transformer Station Equipment - Normally Primary above 50 kV	1815	$8,444,496	$8,509,131	$64,635
1820 - Distribution Station Equipment - Normally Primary below 50 kV	1820	$12,181,995	$42,182,458	$30,000,462
1825 - Storage Battery Equipment	1825	$13,722	$13,722	$0
1830 - Poles, Towers and Fixtures	1830	$24,983,155	$28,543,225	$3,560,071
1835 - Overhead Conductors and Devices	1835	$15,876,144	$18,546,474	$2,670,330
1840 - Underground Conduit	1840	$4,808,197	$5,444,141	$635,945
1845 - Underground Conductors and Devices	1845	$15,191,109	$16,327,524	$1,136,415
1850 - Line Transformers	1850	$16,603,673	$17,533,003	$929,330
1855 - Services	1855	$8,176,278	$8,679,331	$503,053
1860 - Meters	1860	$5,753,920	$5,927,089	$173,168
1865 - Other Installations on Customer's Premises	1865	$0	$0	$0
1995 - Contributions and Grants	1995	($11,161,739)	($11,161,739)	$0
2440 - Deferred Revenue	2440	($5,929,786)	($13,778,024)	($7,848,238)
Sub-Total Distribution Assets		**$124,652,566**	**$156,513,564**	**$31,860,998**
General Plant				
1980 - System Supervisory Equipment	1980	$1,833,182	$5,322,336	$3,489,154
1985 - Sentinel Lighting Rentals	1985	$0	$0	$0
1990 - Other Tangible Property	1990	$0	$0	$0
Sub-Total General Plant		**$1,833,182**	**$5,322,336**	**$3,489,154**
GROSS ASSET TOTAL		**$126,485,748**	**$161,835,900**	**$35,350,152**

2

The following summarizes the major components of the $35,350,152 variance between 2021 Actual and 2022 Bridge Year Gross Assets.

ACCOUNT 1820 Distribution Station Equipment $30,000,462

- Distribution station upgrades - $459,170 – Battery bank replacements/additions, SCADA and communication equipment renewal, breaker upgrades, relay upgrades, RTU upgrades and forced renewal.
- Sub 16 additions - $6,020,120 – Sub 16 total spend brought into rate base as part of 2022 Bridge Year.
- SSG station renewal - $3,357,721 – Capital funds reallocated for SSG. station renewal previously intended for another replacement of substation.
- SSG project - $20,622,622 – update net project value of SSG brought into rate base as part of 2022 Bridge Year.
- Various other immaterial items - $0.

ACCOUNT 1830 Poles, Towers and Fixtures $3,560,071

- New services and subdivisions –$774,758.
- Joint Use Make Ready - $49,443.
- Road Construction Projects - $40,306 – Replace deteriorated poles in conjunction with City Road projects.
- Forced Overhead renewal (renewal due to storm damage, traffic accidents, etc.) - $131,688 – Traffic accidents and unplanned miscellaneous capital replacements.
- Overhead renewal program - $1,471,159 - Replace deteriorated poles at various locations as required. Restricted Wire Replacement and Voltage Conversion.
- SSG - $1,092,717.

- Various other immaterial items - $19,169.

ACCOUNT 1835 Overhead Conductors and Devices $2,670,330

- New services and subdivisions - $219,446.
- Joint Use (Make Ready) work - $16,481.
- Road Construction Projects - $13,435.
- Forced overhead renewal - $43,889.
- Overhead renewal program - $258,699 – Voltage conversion and restricted wire.
- SSG - $2,118,379.

ACCOUNT 1840 Underground Conduit $635,945

- New services and subdivision - $146,297.
- Voltage Conversion and Restricted Wire - $154,060.
- Forced underground renewal - $241,838 – Traffic accidents and unplanned miscellaneous capital replacements.
- Various other immaterial items - $93,749.

ACCOUNT 1845 Underground Conductors and Devices $1,136,415

- SSG project - $1,023,106.
- Underground renewal program - $48,368 – Vault replacements and miscellaneous unplanned capital replacements.
- PM Switchgear - $59,713.
- Various Other Immaterial items - $5,228.

ACCOUNT 1850 Line Transformers $923,330

- SSG - $367,369.
- New services and subdivisions - $262,738.
- Forced OH and UG Renewal - $61,505.
- Voltage conversion and restricted wire - $154,060.
- PM transformers - $41,823.
- Various other immaterial items - $41,836.

ACCOUNT 1855 Services $503,053

- New services and subdivisions - $59,713 – Customer demand residential services and customer demand commercial services.
- Forced OH renewal - $58,519.
- Voltage conversion and restricted wire - $308,120.
- Various other immaterial items - $76,701.

ACCOUNT 1860 Smart Meters $173,168

- Meter installations - $173,168 – Install new electric meters.

ACCOUNT 1980 System Supervisory Equipment $3,489,154

- SSG - $3,489,154

ACCOUNT 2440 Deferred Revenue ($7,848,238)

- New Services & Subdivisions – ($456,050) - Customer demand residential services and customer demand commercial services.

- Overhead forced renewal – ($36,750) – Motor vehicle accident recoveries.
- SSG project – ($7,355,438).

2022 Bridge vs. 2023 Test Year

PUC's overall increase in Gross Assets between 2022 Bridge and 2023 Test is $10,113,371 as can be seen in the following Table 2-11.

1 **Table 2-11: 2022 Bridge vs. 2023 Test Year**

Description		2022 Bridge	2023 Test	Variance 2022 Bridge vs. 2023 Test
Reporting Basis		MIFRS	MIFRS	
Distribution Assets				
1706 - Land Rights	1706	$602,307	$602,307	$0
1725 - TX Poles & Fixtures	1725	$1,604,339	$1,604,339	$0
1730 - TX OH Conductors	1730	$63,894	$63,894	$0
1735 - TX UG Conduit	1735	$870,020	$870,020	$0
1740 - TX UG Conductors	1740	$215,252	$215,252	$0
1805 - Land	1805	$56,415	$56,415	$0
1806 - Land Rights	1806	$0	$0	$0
1612 - Land Rights	1612	$375,398	$375,398	$0
1808 - Buildings and Fixtures	1808	$25,959,603	$26,536,638	$577,035
1810 - Leasehold Improvements	1810	$0	$0	$0
1815 - Transformer Station Equipment - Normally Primary above 50 kV	1815	$8,509,131	$8,785,104	$275,973
1820 - Distribution Station Equipment - Normally Primary below 50 kV	1820	$42,182,458	$44,963,085	$2,780,627
1825 - Storage Battery Equipment	1825	$13,722	$13,722	$0
1830 - Poles, Towers and Fixtures	1830	$28,543,225	$31,121,915	$2,578,690
1835 - Overhead Conductors and Devices	1835	$18,546,474	$19,358,420	$811,945
1840 - Underground Conduit	1840	$5,444,141	$6,535,703	$1,091,561
1845 - Underground Conductors and Devices	1845	$16,327,524	$16,502,355	$174,831
1850 - Line Transformers	1850	$17,533,003	$18,835,671	$1,302,668
1855 - Services	1855	$8,679,331	$9,197,207	$517,876
1860 - Meters	1860	$5,927,089	$6,134,068	$206,980
1865 - Other Installations on Customer's Premises	1865	$0	$0	$0
1995 - Contributions and Grants	1995	($11,161,739)	($11,161,739)	$0
2440 - Deferred Revenue	2440	($13,778,024)	($14,370,524)	($592,500)
Sub-Total Distribution Assets		**$156,513,564**	**$166,239,251**	**$9,725,687**
General Plant				
1980 - System Supervisory Equipment	1980	$5,322,336	$5,710,020	$387,684
1985 - Sentinel Lighting Rentals	1985	$0	$0	$0
1990 - Other Tangible Property	1990	$0	$0	$0
Sub-Total General Plant		**$5,322,336**	**$5,710,020**	**$387,684**
GROSS ASSET TOTAL		**$161,835,900**	**$171,949,271**	**$10,113,371**

2

The following summarizes the major components of the $10,113,3717 variance between 2022 Bridge and 2023 Test Year Gross Assets.

ACCOUNT 1808 Buildings and Fixtures $577,035

- General tools/equipment for Stations - $294,789.
- Upgrades and renewal of PUC's facility located at 500 Second Line E - $238,340.

ACCOUNT 1815 Transformer Station Equipment $275,973

- Forced Renewal - $75,265.
- Transformer Station Upgrades - $200,708.

ACCOUNT 1820 Distribution Station Equipment $2,780,627

- Forced Renewal - $75,265.
- Distribution Station Upgrades/Fixtures - $413,960.
- SSG - $2,291,402.

ACCOUNT 1830 Poles, Towers and Fixtures $2,578,690

- New services and subdivisions - $859,280.
- Joint Use (Make Read) - $112,898.
- Road Construction Projects - $112,898 – Replace deteriorated poles in conjunction with City Road projects. Areas completed include.
- Overhead renewal program - $679,741 - Replace deteriorated poles at various locations as required.
- Smart grid project - $220,684

- Forced Overhead renewal (renewal due to storm damage, traffic accidents, etc.) - $141,123 – Traffic accidents and unplanned miscellaneous capital replacements.
- Restricted wire program - $162,686.
- Voltage Conversion Program - $388,652.
- Various other immaterial items - $41,851.

ACCOUNT 1835 Overhead Conductors and Devices $811,945

- New services and subdivisions - $244,613.
- Joint Use (Make Ready) work - $37,633.
- City Projects - $37,633.
- Forced overhead renewal - $47,041.
- Overhead renewal program - $183,799 – Voltage conversion and restricted wire.
- SSG - $261,226.

ACCOUNT 1840 Underground Conduit $1,091,561

- New services and subdivision - $163,075.
- Voltage Conversion and Restricted Wire - $122,520.
- Forced underground renewal - $282,245 – Traffic accidents and unplanned miscellaneous capital replacements.
- Vault Replacement - $401,415.
- Various other immaterial items - $122,306.

ACCOUNT 1845 Underground Conductors and Devices $174,831

- SSG - $113,678.
- Various Other immaterial items - $27,283.

ACCOUNT 1850 Line Transformers $1,302,668

- New services and subdivisions - $288,517.
- Forced OH and UG Renewal - $68,933.
- Voltage conversion and restricted wire - $122,520.
- Overhead Renewal Program - $711,528 for transformers.
- Various other immaterial items - $70,561.
- SSG - $40,819.

ACCOUNT 1855 Services $517,876

- New Services and Subdivisions - $75,265.
- City Projects - $50,177.
- Joint Use - $50,177.
- Forced OH Renewal - $62,271.
- Voltage Conversion - $172,734.
- Restricted Wire - $72,305.

ACCOUNT 1860 Smart Meters $206,980

- Meter installations - $206,980 – Install new electric meters.

ACCOUNT 1980 System Supervisory Equipment $387,684

- SSG - $387,684.

ACCOUNT 2440 Deferred Revenue ($592,500)

- New Services & Subdivisions – ($555,000) - Customer demand residential services and customer demand commercial services.
- Overhead forced renewal – ($37,500) – Motor vehicle accident recoveries.

2.3 GROSS ASSETS – PROPERTY, PLANT & EQUIPMENT AND ACCUMULATED DEPRECIATION

2.3.1 Breakdown by Function

Table 2-6 through 2-11 categorize PUC's assets into four categories; transmission plant, distribution plant, general plant, and contributions and grants. In accordance with the Uniform System of Accounts ("USoA"), PUC has included gross assets as follows:

- Transmission Plant Assets – includes USoA accounts 1706-1740, these accounts capture assets such as transmission poles, wires, and transformers.
- Distribution Plant Assets – includes USoA accounts 1805-1860, these accounts capture assets such as substation equipment, poles, wires, transformers and meters.
- General Plant Assets – includes USoA account 1905 to 1990, these accounts capture assets such as operation service center buildings, computer hardware, software, and system supervisory equipment.
- Contributions and Grants – includes USoA account 1995, this account captures all contributions in aid of capital that PUC has received prior to 2014. Account 2440 is used to record all contributions and grants after 2014. PUC has a large jump in contributions and grants in the bridge year from the Natural Resources Canada ("NRCan") grant received for SSG. A separate sub account of 2440 is used to record accumulated

depreciation/recognized revenue on contributions and grants after 2014. Table 2-12 below summarizes the amounts from 2018 to 2023.

Table 2-12: Contributions

Description	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge	2023 Test
Contributions Pre 2014	($11,161,739)	($11,161,739)	($11,161,739)	($11,161,739)	($11,161,739)	($11,161,739)
Accumulated Amortizations	$1,641,432	$1,969,719	$2,298,005	$2,626,292	$2,954,578	$3,282,864
ontribution and Grants Pre 2014	**($9,520,307)**	**($9,192,021)**	**($8,863,734)**	**($8,535,448)**	**($8,207,161)**	**($7,878,875)**
Contributions and Grants	($3,518,564)	($4,630,407)	($5,288,573)	($5,929,786)	($13,778,024)	($14,370,524)
Accumulated Amortizations	$233,597	$335,459	$459,446	$599,676	$846,023	$1,197,880
ntribution and Grants After 2014	**($3,284,967)**	**($4,294,948)**	**($4,829,126)**	**($5,330,111)**	**($12,932,001)**	**($13,172,644)**
tal Net Contributions and Grants	**($12,805,274)**	**($13,486,968)**	**($13,692,860)**	**($13,865,558)**	**($21,139,162)**	**($21,051,519)**

Summary of ICM Adjustments

PUC received approval for 2 ICM applications through the period 2018-2022. PUC received approval for the rebuild of Sub 16, in the amount of $4,728,229, as part of its 2019 ICM Application (EB-2019-0170). In 2021, PUC also received approval for the SSG project, in the amount of $24,828,660 net of contributions and grants, as part of its 2022 ICM application (EB-2018-0219/EB-2020-0249). PUC's rebuild of Sub 16 came in at a cost of $6,020,119 and PUC's SSG project is still under construction at an updated value of $21,357,909 which is net of NRCAN funding to be received.

The Sub 16 rebuild and the SSG project have been brought into rate base in 2022 at a value of $6,020,119 and $21,357,909 respectively. PUC included the values in the 2022 Bridge year to ensure the average net book values were properly reflected in the 2023 Test Year. The amount of capital, and corresponding depreciation that has been brought into rate base is based on actual expenditures for each respective project. A summary of the approved amounts versus the actual spending and corresponding variances has been provided in Table 2-13.

Table 2-13: ICM Assets includes in 2023 Rate Base

	Substation 16			Sault Smart Grid		
	Approved	Actual	Variance	Approved	Actual	Variance
Gross Capital	$4,728,229	$6,020,119	$1,291,890	$24,828,660	$21,357,909	($3,470,751)
Depreciation	$117,206	$150,503	$33,297	$695,799	$600,448	($95,351)
Accumulated Depreciation	$293,015	$225,754	($67,261)	$695,799	$600,448	($95,351)
Net Book Value for 2023 test year (Gross Cap less Accum Dep)	$4,435,214	$5,794,365	$1,359,151	$24,132,861	$20,757,461	($3,375,400)

Sub 16 had an increase in project value of $1,291,890 which correspondingly increases depreciation. The accumulated depreciation is lower as compared to the approved ICM as Sub 16 was not in service until December 31, 2021 for reasons explained in Section 2.8 below.

SSG had a decrease in project value of $3,470,751 due to timing of project completion and an updated amount in grants from NRCan. The project timeline was updated to reflect $3,190,371 of the total project costs being completed in Q1 2023 and therefore this amount has been removed from the ICM project and included as part of 2023 capital additions.

A full reconciliation of both projects has been provided in Section 2.8 below.

2.4 DEPRECIATION, AMORTIZATION and DEPLETION

2.4.1 Depreciation Policy

Amortization on capital assets is calculated as follows:

- PUC uses the pooling of assets for all fixed assets. Amortization is calculated on a straight-line basis over the estimated useful life of the assets commencing when the asset is put in service.
- PUC uses the Kinetrics Report when establishing the useful lives of its assets. PUC has completed the Kinetrics Report from Chapter 2 Appendices 2 BB which is included in the live excel model. PUC follows the Kinetrics Report for all assets categories except accounts 1730 Transmission Overhead Conductors, and 1808 Buildings and Fixtures. When PUC implemented IFRS the building was componentized with different life spans based on the useful life of each component. The different lifespans are explained below:
    - Account 1730, Transmission Overhead Conductors, PUC uses a useful life of 45 years.
    - Account 1808, Buildings and Fixtures has been componentized to distinguish between the different lifespans for the building at 500 Second Line E. PUC uses the following useful lives for each categorized component:
        - Building – 50 years
        - Parking/Paving – 20 Years
        - Landscaping – 20 Years
        - Roof – 30 Years
        - Finishes – 30 Years
        - HVAC/Mechanical – 50 Years
        - Electrical – 40 Years
- OEB guidelines require LDCs to use the half-year rule when accounting for amortization expense. PUC's Amortization policy matches OEB guidelines with half year amortization on capital additions. No changes have been made to PUC's depreciation policy or service lives since the last rebasing, other than noted above.

- For the purposes of calculating depreciation for this Application, the half-year rule has been applied for all capital additions and capital contributions that enter service in the test year.
- Tables 2-14 through 2-19 provide a summary by year for 2018 Actual, 2019 Actual, 2020 Actual, 2021 Actual, 2022 Bridge and 2023 Test Year, respectively, of PUC's depreciation expense.

Construction in progress assets are not depreciated until the project is complete. PUC charges construction interest in accordance with the OEB's CWIP Prescribed interest rate.
The tables beginning with Table 2-14 and ending with Table 2-19 provide a summary by year for 2018 Actual, 2019 Actual, 2020 Actual, 2021 Actual, 2022 Bridge Year and 2023 Test Year of depreciation expense including asset amounts and depreciation rates. These tables reflect the Accumulated Depreciation balances in the Fixed Asset Continuity schedule in Exhibit 2, which are consistent with the Board's Appendix 2-BA. PUC has completed the Appendix 2-C which is part of the Chapter 2 Appendices and attached as Appendix B. There are some minor variances year over year which are immaterial. However, in 2020, PUC over depreciated assets in account 1980. This caused an over depreciation of $230,628. This was corrected in the following year and does not affect the test year depreciation.

PUC has brought both ICM's (Sub 16 and SSG) into rate base in 2022. Sub 16 had a half year of depreciation in 2021 and full year in 2022. Chapter 2 Appendices 2-C is showing a variance of $150,503 in 2022 Bridge Year. This is because the formula doesn't account for the fact that Sub 16 had a half year worth of depreciation when it was part of 1508 regulatory assets.

Table 2-14: 2018 Actual Depreciation

Accounting Standard	MIFRS
Year	**2018**

			Cost				Accumulated Depreciation				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -	$ -		$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339			$ 1,604,339	$ 156,521	$ 39,130		$ 195,651	$ 1,408,688
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	$ 7,987	$ 1,997		$ 9,983	$ 53,911
47	1735	Underground Conduit	$ 870,020			$ 870,020	$ 99,431	$ 24,858		$ 124,289	$ 745,732
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	$ 39,137	$ 9,784		$ 48,921	$ 166,331
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)				$ -				$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 89,160	$ -	-$ 32,744	$ 56,415				$ -	$ 56,415
CEC	1806	Land Rights	$ 178,951	$ 10,405		$ 189,356				$ -	$ 189,356
47	1808	Buildings	$ 25,027,092	$ 8,455		$ 25,035,547	$ 2,717,413	$ 683,038		$ 3,400,451	$ 21,635,096
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 7,662,606	$ 292,263		$ 7,954,869	$ 1,000,670	$ 286,747		$ 1,287,417	$ 6,667,452
47	1820	Distribution Station Equipment <50 kV	$ 10,510,642	$ 338,454		$ 10,849,096	$ 1,597,765	$ 426,800		$ 2,024,565	$ 8,824,531
47	1825	Storage Battery Equipment	$ 13,722	$ -		$ 13,722	$ 2,614	$ 653		$ 3,267	$ 10,455
47	1830	Poles, Towers & Fixtures	$ 17,808,103	$ 1,743,944		$ 19,552,048	$ 1,301,617	$ 420,389		$ 1,722,005	$ 17,830,043
47	1835	Overhead Conductors & Devices	$ 12,985,479	$ 953,873		$ 13,939,351	$ 1,073,638	$ 317,104		$ 1,390,742	$ 12,548,610
47	1840	Underground Conduit	$ 3,662,059	$ 405,688		$ 4,067,747	$ 897,887	$ 238,547		$ 1,136,434	$ 2,931,313
47	1845	Underground Conductors & Devices	$ 13,447,279	$ 311,100		$ 13,758,378	$ 2,105,522	$ 551,408		$ 2,656,931	$ 11,101,447
47	1850	Line Transformers	$ 13,256,636	$ 722,098		$ 13,978,734	$ 1,130,181	$ 346,378		$ 1,476,559	$ 12,502,175
47	1855	Services (Overhead & Underground)	$ 6,076,631	$ 577,442		$ 6,654,074	$ 583,072	$ 166,936		$ 750,009	$ 5,904,065
47	1860	Meters	$ 4,838,566	$ 145,913		$ 4,984,479	$ 1,678,254	$ 435,774		$ 2,114,028	$ 2,870,451
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment	$ 1,600,673	$ 66,076		$ 1,666,749	$ 952,647	$ 242,873		$ 1,195,521	$ 471,228
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739	$ -		-$ 11,161,739	-$ 1,313,146	-$ 328,286		-$ 1,641,432	-$ 9,520,307
47	2440	Deferred Revenue[5]	-$ 3,087,531	-$ 431,033		-$ 3,518,564	-$ 151,021	-$ 82,576		-$ 233,597	-$ 3,284,967
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 106,264,142**	**$ 5,144,679**	**-$ 32,744**	**$ 111,376,076**	**$ 13,880,189**	**$ 3,781,554**	**$ -**	**$ 17,661,743**	**$ 93,714,333**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 106,264,142**	**$ 5,144,679**	**-$ 32,744**	**$ 111,376,076**	**$ 13,880,189**	**$ 3,781,554**	**$ -**	**$ 17,661,743**	**$ 93,714,333**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 3,781,554**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 82,576
			Net Depreciation	**$ 3,864,131**

Table 2-15: 2019 Actual Depreciation

Accounting Standard MIFRS
Year 2019

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -			$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339			$ 1,604,339	$ 195,651	$ 39,130		$ 234,781	$ 1,369,558
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	$ 9,983	$ 1,997		$ 11,980	$ 51,914
47	1735	Underground Conduit	$ 870,020			$ 870,020	$ 124,289	$ 24,858		$ 149,146	$ 720,874
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	$ 48,921	$ 9,784		$ 58,705	$ 156,547
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 56,415			$ 56,415	$ -			$ -	$ 56,415
ECE	1806	Land Rights	$ 189,356	$ 14,311		$ 203,667	$ -			$ -	$ 203,667
47	1808	Buildings	$ 25,035,547	$ 177,803		$ 25,213,351	$ 3,400,451	$ 686,763		$ 4,087,214	$ 21,126,136
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 7,954,869	$ 233,949		$ 8,188,818	$ 1,287,417	$ 293,325		$ 1,580,742	$ 6,608,076
47	1820	Distribution Station Equipment <50 kV	$ 10,849,096	$ 226,273		$ 11,075,369	$ 2,024,565	$ 433,859		$ 2,458,424	$ 8,616,944
47	1825	Storage Battery Equipment	$ 13,722			$ 13,722	$ 3,267	$ 653		$ 3,920	$ 9,801
47	1830	Poles, Towers & Fixtures	$ 19,552,048	$ 2,058,945		$ 21,610,992	$ 1,722,005	$ 462,643		$ 2,184,648	$ 19,426,344
47	1835	Overhead Conductors & Devices	$ 13,939,351	$ 646,542		$ 14,585,893	$ 1,390,742	$ 330,441		$ 1,721,182	$ 12,864,711
47	1840	Underground Conduit	$ 4,067,747	$ 494,913		$ 4,562,660	$ 1,136,434	$ 247,553		$ 1,383,987	$ 3,178,674
47	1845	Underground Conductors & Devices	$ 13,758,378	$ 314,478		$ 14,072,856	$ 2,656,931	$ 559,228		$ 3,216,159	$ 10,856,697
47	1850	Line Transformers	$ 13,978,734	$ 898,402		$ 14,877,136	$ 1,476,559	$ 367,055		$ 1,843,614	$ 13,033,522
47	1855	Services (Overhead & Underground)	$ 6,654,074	$ 536,808		$ 7,190,881	$ 750,009	$ 190,040		$ 940,049	$ 6,250,832
47	1860	Meters	$ 4,984,479	$ 76,616		$ 5,061,095	$ 2,114,028	$ 443,191		$ 2,557,219	$ 2,503,876
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,666,749	$ 156,497		$ 1,823,246	$ 1,195,521	$ 248,438		$ 1,443,958	$ 379,288
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739			-$ 11,161,739	-$ 1,641,432	-$ 328,286		-$ 1,969,719	-$ 9,192,021
47	2440	Deferred Revenue[5]	-$ 3,518,564	-$ 1,111,843		-$ 4,630,407	-$ 233,597	-$ 101,862		-$ 335,459	-$ 4,294,948
	2005	Property Under Finance Lease[7]				$ -	0			$ -	$ -
		Sub-Total	**$ 111,376,076**	**$ 4,723,694**	**$ -**	**$ 116,099,770**	**$ 17,661,743**	**$ 3,908,810**	**$ -**	**$ 21,570,553**	**$ 94,529,217**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 111,376,076**	**$ 4,723,694**	**$ -**	**$ 116,099,770**	**$ 17,661,743**	**$ 3,908,810**	**$ -**	**$ 21,570,553**	**$ 94,529,217**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 3,908,810**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 101,862
			Net Depreciation	**$ 4,010,672**

Table 2-16: 2020 Actual Depreciation

Accounting Standard: MIFRS
Year: 2020

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -			$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339			$ 1,604,339	$ 234,781	$ 39,130		$ 273,912	$ 1,330,428
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	$ 11,980	$ 1,997		$ 13,977	$ 49,917
47	1735	Underground Conduit	$ 870,020			$ 870,020	$ 149,146	$ 24,858		$ 174,004	$ 696,016
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	$ 58,705	$ 9,784		$ 68,489	$ 146,763
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 56,415			$ 56,415	$ -			$ -	$ 56,415
CEC	1806	Land Rights	$ 203,667	$ 14,268		$ 217,935	$ -			$ -	$ 217,935
47	1808	Buildings	$ 25,213,351	$ 125,719		$ 25,339,070	$ 4,087,214	$ 692,833		$ 4,780,048	$ 20,559,022
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,188,818	$ 184,850		$ 8,373,668	$ 1,580,742	$ 298,560		$ 1,879,302	$ 6,494,366
47	1820	Distribution Station Equipment <50 kV	$ 11,075,369	$ 531,294		$ 11,606,662	$ 2,458,424	$ 443,329		$ 2,901,753	$ 8,704,909
47	1825	Storage Battery Equipment	$ 13,722			$ 13,722	$ 3,920	$ 653		$ 4,574	$ 9,148
47	1830	Poles, Towers & Fixtures	$ 21,610,992	$ 1,797,499		$ 23,408,492	$ 2,184,648	$ 505,492		$ 2,690,141	$ 20,718,351
47	1835	Overhead Conductors & Devices	$ 14,585,893	$ 783,153		$ 15,369,046	$ 1,721,182	$ 342,355		$ 2,063,537	$ 13,305,509
47	1840	Underground Conduit	$ 4,562,660	$ 62,255		$ 4,624,916	$ 1,383,987	$ 253,124		$ 1,637,111	$ 2,987,805
47	1845	Underground Conductors & Devices	$ 14,072,856	$ 554,440		$ 14,627,297	$ 3,216,159	$ 570,090		$ 3,786,249	$ 10,841,048
47	1850	Line Transformers	$ 14,877,136	$ 953,608		$ 15,830,744	$ 1,843,614	$ 388,011		$ 2,231,625	$ 13,599,120
47	1855	Services (Overhead & Underground)	$ 7,190,881	$ 392,402		$ 7,583,283	$ 940,049	$ 197,068		$ 1,137,117	$ 6,446,167
47	1860	Meters	$ 5,061,095	$ 476,303		$ 5,537,398	$ 2,557,219	$ 461,622		$ 3,018,841	$ 2,518,557
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,823,246	$ 9,935		$ 1,833,182	$ 1,443,958	$ 252,599		$ 1,696,557	$ 136,625
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739			-$ 11,161,739	-$ 1,969,719	-$ 328,286		-$ 2,298,005	-$ 8,863,734
47	2440	Deferred Revenue[5]	-$ 4,630,407	-$ 658,166		-$ 5,288,573	-$ 335,459	-$ 123,987		-$ 459,446	-$ 4,829,126
	2005	Property Under Finance Lease[7]	0			$ -	0			$ -	$ -
		Sub-Total	**$ 116,099,770**	**$ 5,227,561**	**$ -**	**$ 121,327,331**	**$ 21,570,553**	**$ 4,029,231**	**$ -**	**$ 25,599,783**	**$ 95,727,548**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 116,099,770**	**$ 5,227,561**	**$ -**	**$ 121,327,331**	**$ 21,570,553**	**$ 4,029,231**	**$ -**	**$ 25,599,783**	**$ 95,727,548**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 4,029,231**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 123,987
			Net Depreciation	**$ 4,153,218**

Table 2-17: 2021 Actual Depreciation

Accounting Standard	MIFRS
Year	**2021**

			Cost				**Accumulated Depreciation**				
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -			$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339			$ 1,604,339	$ 273,912	$ 39,130		$ 313,042	$ 1,291,298
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	$ 13,977	$ 1,997		$ 15,974	$ 47,921
47	1735	Underground Conduit	$ 870,020			$ 870,020	$ 174,004	$ 24,858		$ 198,862	$ 671,159
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	$ 68,489	$ 9,784		$ 78,274	$ 136,979
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 56,415			$ 56,415	$ -			$ -	$ 56,415
CEC	1806	Land Rights	$ 217,935	$ 157,463		$ 375,398	$ -			$ -	$ 375,398
47	1808	Buildings	$ 25,339,070	$ 584,705		$ 25,923,775	$ 4,780,048	$ 706,421		$ 5,486,469	$ 20,437,306
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,373,668	$ 70,828		$ 8,444,495	$ 1,879,302	$ 301,756		$ 2,181,057	$ 6,263,438
47	1820	Distribution Station Equipment <50 kV	$ 11,606,662	$ 575,333		$ 12,181,995	$ 2,901,753	$ 457,162		$ 3,358,915	$ 8,823,081
47	1825	Storage Battery Equipment	$ 13,722			$ 13,722	$ 4,574	$ 653		$ 5,227	$ 8,494
47	1830	Poles, Towers & Fixtures	$ 23,408,492	$ 1,574,663		$ 24,983,155	$ 2,690,141	$ 542,961		$ 3,233,102	$ 21,750,053
47	1835	Overhead Conductors & Devices	$ 15,369,046	$ 507,099		$ 15,876,144	$ 2,063,537	$ 353,107		$ 2,416,644	$ 13,459,500
47	1840	Underground Conduit	$ 4,624,916	$ 183,281		$ 4,808,197	$ 1,637,111	$ 255,580		$ 1,892,691	$ 2,915,506
47	1845	Underground Conductors & Devices	$ 14,627,297	$ 563,813		$ 15,191,109	$ 3,786,249	$ 584,068		$ 4,370,317	$ 10,820,793
47	1850	Line Transformers	$ 15,830,744	$ 772,929		$ 16,603,673	$ 2,231,625	$ 406,873		$ 2,638,498	$ 13,965,175
47	1855	Services (Overhead & Underground)	$ 7,583,283	$ 592,995		$ 8,176,278	$ 1,137,117	$ 209,385		$ 1,346,502	$ 6,829,776
47	1860	Meters	$ 5,537,398	$ 216,522		$ 5,753,920	$ 3,018,841	$ 484,716		$ 3,503,557	$ 2,250,364
47	1860	Meters (Smart Meters)	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 1,833,182	$ -		$ 1,833,182	$ 1,696,557	-$ 207,938		$ 1,488,619	$ 344,563
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739			-$ 11,161,739	-$ 2,298,005	-$ 328,286		-$ 2,626,292	-$ 8,535,448
47	2440	Deferred Revenue[5]	-$ 5,288,573	-$ 641,214		-$ 5,929,786	-$ 459,446	-$ 140,229		-$ 599,676	-$ 5,330,111
	2005	Property Under Finance Lease[7]	0			$ -	0			$ -	$ -
		Sub-Total	**$ 121,327,331**	**$ 5,158,416**	**$ -**	**$ 126,485,747**	**$ 25,599,783**	**$ 3,701,996**	**$ -**	**$ 29,301,780**	**$ 97,183,968**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 121,327,331**	**$ 5,158,416**	**$ -**	**$ 126,485,747**	**$ 25,599,783**	**$ 3,701,996**	**$ -**	**$ 29,301,780**	**$ 97,183,968**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 3,701,996**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 140,229
			Net Depreciation	**$ 3,842,226**

Table 2-18: 2022 Bridge Year Depreciation

Accounting Standard MIFRS
Year 2022

			Cost						Accumulated Depreciation						
CCA Class [2]	**OEB Account [3]**	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**ICM Sub 16**	**ICM SSG**	**Closing Balance**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**ICM Sub 16**	**ICM SSG**	**Closing Balance**	**Net Book Value**
N/A	1706	Land Rights	$ 602,307					$ 602,307	$ -					$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339					$ 1,604,339	$ 313,042	$ 39,130				$ 352,172	$ 1,252,167
47	1730	Overhead Conductors & Devices	$ 63,894					$ 63,894	$ 15,974	$ 1,997				$ 17,970	$ 45,924
47	1735	Underground Conduit	$ 870,020					$ 870,020	$ 198,862	$ 24,858				$ 223,720	$ 646,301
47	1740	Underground Conductors & Devices	$ 215,252					$ 215,252	$ 78,274	$ 9,784				$ 88,058	$ 127,194
	1609	Capital Contributions Paid	$ -					$ -	$ -					$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -					$ -	$ -					$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -					$ -	$ -					$ -	$ -
N/A	1805	Land	$ 56,415					$ 56,415	$ -					$ -	$ 56,415
CEC	1806	Land Rights	$ 375,398					$ 375,398	$ -					$ -	$ 375,398
47	1808	Buildings	$ 25,923,775	$ 35,828				$ 25,959,603	$ 5,486,469	$ 719,297				$ 6,205,766	$ 19,753,837
13	1810	Leasehold Improvements	$ -					$ -	$ -					$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,444,495	$ 64,636				$ 8,509,131	$ 2,181,057	$ 303,449				$ 2,484,506	$ 6,024,625
47	1820	Distribution Station Equipment <50 kV	$ 12,181,995	$ 3,357,721		$ 6,020,120	$ 20,622,622	$ 42,182,458	$ 3,358,915	$ 506,325		$ 225,754	$ 257,783	$ 4,348,777	$ 37,833,681
47	1825	Storage Battery Equipment	$ 13,722	$ -				$ 13,722	$ 5,227	$ 653				$ 5,881	$ 7,841
47	1830	Poles, Towers & Fixtures	$ 24,983,155	$ 2,467,354			$ 1,092,717	$ 28,543,225	$ 3,233,102	$ 587,872			$ 12,141	$ 3,833,115	$ 24,710,110
47	1835	Overhead Conductors & Devices	$ 15,876,144	$ 551,951			$ 2,118,379	$ 18,546,474	$ 2,416,644	$ 361,932			$ 17,653	$ 2,796,230	$ 15,750,244
47	1840	Underground Conduit	$ 4,808,197	$ 635,945			$ -	$ 5,444,141	$ 1,892,691	$ 263,772			$ -	$ 2,156,463	$ 3,287,678
47	1845	Underground Conductors & Devices	$ 15,191,109	$ 113,309			$ 1,023,106	$ 16,327,524	$ 4,370,317	$ 592,532			$ 12,789	$ 4,975,637	$ 11,351,887
47	1850	Line Transformers	$ 16,603,673	$ 561,961			$ 367,369	$ 17,533,003	$ 2,638,498	$ 423,863			$ 4,592	$ 3,066,953	$ 14,466,050
47	1855	Services (Overhead & Underground)	$ 8,176,278	$ 503,053				$ 8,679,331	$ 1,346,502	$ 223,086				$ 1,569,587	$ 7,109,743
47	1860	Meters	$ 5,753,920	$ 173,168				$ 5,927,089	$ 3,503,557	$ 497,706				$ 4,001,263	$ 1,925,826
47	1975	Load Management Controls Utility Premises	$ -					$ -	$ -					$ -	$ -
47	1980	System Supervisor Equipment	$ 1,833,182				$ 3,489,154	$ 5,322,336	$ 1,488,619	$ 22,579			$ 87,229	$ 1,598,426	$ 3,723,909
47	1985	Miscellaneous Fixed Assets	$ -					$ -	$ -					$ -	$ -
47	1990	Other Tangible Property	$ -					$ -	$ -					$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739					-$ 11,161,739	-$ 2,626,292	-$ 328,286				-$ 2,954,578	-$ 8,207,161
47	2440	Deferred Revenue[5]	-$ 5,929,786	-$ 492,800			-$ 7,355,438	-$ 13,778,024	-$ 599,676	-$ 154,405			-$ 91,943	-$ 846,023	-$ 12,932,001
	2005	Property Under Finance Lease[7]	0					$ -	0					$ -	$ -
		Sub-Total	**$ 126,485,747**	**$ 7,972,124**	**$ -**	**$ 6,020,120**	**$ 21,357,909**	**$ 161,835,900**	**$ 29,301,780**	**$ 4,096,144**	**$ -**	**$ 225,754**	**$ 300,244**	**$ 33,923,922**	**$ 127,911,978**
		Less Socialized Renewable Energy Generation Investments (input as negative)						$ -						$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -						$ -	$ -
		Total PP&E	**$ 126,485,747**	**$ 7,972,124**	**$ -**	**$ 6,020,120**	**$ 21,357,909**	**$ 161,835,900**	**$ 29,301,780**	**$ 4,096,144**	**$ -**	**$ 225,754**	**$ 300,244**	**$ 33,923,922**	**$ 127,911,978**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]													
		Total								**$ 4,622,143**					

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 246,348
			Net Depreciation	**$ 4,868,490**

Table 2-19 2023: Test Year Depreciation

Accounting Standard MIFRS
Year 2023

CCA Class [2]	OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
N/A	1706	Land Rights	$ 602,307			$ 602,307	$ -			$ -	$ 602,307
47	1725	Poles and Fixtures	$ 1,604,339			$ 1,604,339	$ 352,172	$ 39,130		$ 391,302	$ 1,213,037
47	1730	Overhead Conductors & Devices	$ 63,894			$ 63,894	$ 17,970	$ 1,997		$ 19,967	$ 43,927
47	1735	Underground Conduit	$ 870,020			$ 870,020	$ 223,720	$ 24,858		$ 248,577	$ 621,443
47	1740	Underground Conductors & Devices	$ 215,252			$ 215,252	$ 88,058	$ 9,784		$ 97,842	$ 117,410
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -			$ -	$ -
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 56,415			$ 56,415	$ -			$ -	$ 56,415
CEC	1806	Land Rights	$ 375,398			$ 375,398	$ -			$ -	$ 375,398
47	1808	Buildings	$ 25,959,603	$ 577,035		$ 26,536,638	$ 6,205,766	$ 731,555		$ 6,937,321	$ 19,599,317
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ 8,509,131	$ 275,973		$ 8,785,104	$ 2,484,506	$ 307,707		$ 2,792,213	$ 5,992,891
47	1820	Distribution Station Equipment <50 kV	$ 42,182,458	$ 2,780,627		$ 44,963,085	$ 4,348,777	$ 583,054		$ 5,597,900	$ 39,365,185
47	1825	Storage Battery Equipment	$ 13,722	$ -		$ 13,722	$ 5,881	$ 653		$ 6,534	$ 7,187
47	1830	Poles, Towers & Fixtures	$ 28,543,225	$ 2,578,690		$ 31,121,915	$ 3,833,115	$ 643,939		$ 4,501,337	$ 26,620,578
47	1835	Overhead Conductors & Devices	$ 18,546,474	$ 811,945		$ 19,358,420	$ 2,796,230	$ 373,298		$ 3,204,834	$ 16,153,586
47	1840	Underground Conduit	$ 5,444,141	$ 1,091,561		$ 6,535,703	$ 2,156,463	$ 281,047		$ 2,437,510	$ 4,098,193
47	1845	Underground Conductors & Devices	$ 16,327,524	$ 174,831		$ 16,502,355	$ 4,975,637	$ 596,134		$ 5,597,348	$ 10,905,007
47	1850	Line Transformers	$ 17,533,003	$ 1,302,668		$ 18,835,671	$ 3,066,953	$ 447,171		$ 3,523,308	$ 15,312,363
47	1855	Services (Overhead & Underground)	$ 8,679,331	$ 517,876		$ 9,197,207	$ 1,569,587	$ 235,847		$ 1,805,434	$ 7,391,772
47	1860	Meters	$ 5,927,089	$ 206,980		$ 6,134,068	$ 4,001,263	$ 510,377		$ 4,511,640	$ 1,622,429
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ 5,322,336	$ 387,684		$ 5,710,020	$ 1,598,426	$ 32,271		$ 1,805,155	$ 3,904,865
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	-$ 11,161,739			-$ 11,161,739	-$ 2,954,578	-$ 328,286		-$ 3,282,864	-$ 7,878,875
47	2440	Deferred Revenue[5]	-$ 13,778,024	-$ 592,500		-$ 14,370,524	-$ 846,023	-$ 167,971		-$ 1,197,880	-$ 13,172,644
	2005	Property Under Finance Lease[7]	0			$ -	0			$ -	$ -
		Sub-Total	**$ 161,835,900**	**$ 10,113,371**	**$ -**	**$ 171,949,271**	**$ 33,923,922**	**$ 4,322,565**	**$ -**	**$ 38,997,478**	**$ 132,951,792**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E	**$ 161,835,900**	**$ 10,113,371**	**$ -**	**$ 171,949,271**	**$ 33,923,922**	**$ 4,322,565**	**$ -**	**$ 38,997,478**	**$ 132,951,792**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**$ 5,073,556**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	
8		Stores Equipment	Stores Equipment	
47		Deferred Revenue	Deferred Revenue	-$ 351,857
			Net Depreciation	**$ 5,425,413**

Table 2-20: Gross Book Value of Assets

Description		Useful Life of Assets	2018 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge	2023 Test
Reporting Basis			**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
Distribution Assets									
1706 - Land Rights	1706		$602,307	$602,307	$602,307	$602,307	$602,307	$602,307	$602,307
1725 - TX Poles & Fixtures	1725	45	$1,604,339	$1,604,339	$1,604,339	$1,604,339	$1,604,339	$1,604,339	$1,604,339
1730 - TX OH Conductors	1730	45	$63,894	$63,894	$63,894	$63,894	$63,894	$63,894	$63,894
1735 - TX UG Conduit	1735	40	$870,020	$870,020	$870,020	$870,020	$870,020	$870,020	$870,020
1740 - TX UG Conductors	1740	25	$215,252	$215,252	$215,252	$215,252	$215,252	$215,252	$215,252
1805 - Land	1805		$89,160	$56,415	$56,415	$56,415	$56,415	$56,415	$56,415
1806 - Land Rights	1806		$0	$0	$0	$0	$0	$0	$0
1612 - Land Rights	1612		$180,572	$189,356	$203,667	$217,935	$375,398	$375,398	$375,398
1808 - Buildings and Fixtures	1808	40	$25,090,191	$25,035,547	$25,213,351	$25,339,070	$25,923,775	$25,959,603	$26,536,638
1810 - Leasehold Improvements	1810		$0	$0	$0	$0	$0	$0	$0
1815 - Transformer Station Equipment - Normally Primary above 50 kV	1815	40	$7,785,385	$7,954,869	$8,188,818	$8,373,668	$8,444,496	$8,509,131	$8,785,104
1820 - Distribution Station Equipment - Normally Primary below 50 kV	1820	40	$10,915,612	$10,849,096	$11,075,369	$11,606,662	$12,181,995	$42,182,458	$44,963,085
1825 - Storage Battery Equipment	1825	30	$13,722	$13,722	$13,722	$13,722	$13,722	$13,722	$13,722
1830 - Poles, Towers and Fixtures	1830	45	$19,395,096	$19,552,048	$21,610,992	$23,408,492	$24,983,155	$28,543,225	$31,121,915
1835 - Overhead Conductors and Devices	1835	60	$13,988,715	$13,939,351	$14,585,893	$15,369,046	$15,876,144	$18,546,474	$19,358,420
1840 - Underground Conduit	1840	50	$3,876,689	$4,067,747	$4,562,660	$4,624,916	$4,808,197	$5,444,141	$6,535,703
1845 - Underground Conductors and Devices	1845	40	$13,799,563	$13,758,378	$14,072,856	$14,627,297	$15,191,109	$16,327,524	$16,502,355
1850 - Line Transformers	1850	40	$14,261,914	$13,978,734	$14,877,136	$15,830,744	$16,603,673	$17,533,003	$18,835,671
1855 - Services	1855	40	$6,534,115	$6,654,074	$7,190,881	$7,583,283	$8,176,278	$8,679,331	$9,197,207
1860 - Meters	1860	15	$4,984,603	$4,984,479	$5,061,095	$5,537,398	$5,753,920	$5,927,089	$6,134,068
1865 - Other Installations on Customer's Premises	1865		$0	$0	$0	$0	$0	$0	$0
1995 - Contributions and Grants	1995	40	($11,161,739)	($11,161,739)	($11,161,739)	($11,161,739)	($11,161,739)	($11,161,739)	($11,161,739)
2440 - Deferred Revenue	2440	40	($3,537,531)	($3,518,564)	($4,630,407)	($5,288,573)	($5,929,786)	($13,778,024)	($14,370,524)
Sub-Total Distribution Assets			**$109,571,879**	**$109,709,327**	**$114,276,524**	**$119,494,150**	**$124,652,566**	**$156,513,564**	**$166,239,251**
General Plant									
1980 - System Supervisory Equipment	1980	20	$1,630,439	$1,666,749	$1,823,246	$1,833,182	$1,833,182	$5,322,336	$5,710,020
1985 - Sentinel Lighting Rentals	1985		$0	$0	$0	$0	$0	$0	$0
1990 - Other Tangible Property	1990		$0	$0	$0	$0	$0	$0	$0
Sub-Total General Plant			**$1,630,439**	**$1,666,749**	**$1,823,246**	**$1,833,182**	**$1,833,182**	**$5,322,336**	**$5,710,020**
GROSS ASSET TOTAL			**$111,202,318**	**$111,376,076**	**$116,099,770**	**$121,327,331**	**$126,485,748**	**$161,835,900**	**$171,949,271**

2.4.2 Asset Retirement Obligations ("AROs")

PUC has not recorded any Asset Retirement Obligations in Fixed Assets.

2.5 ALLOWANCE FOR WORKING CAPITAL

2.5.1 Allowance Factor Overview

In accordance with the Filing Requirements and in a letter dated June 3, 2015[1], the Board updated its policy for the calculation of the allowance for working capital. As outlined in both documents, distributors may take one of two approaches for the calculation of its allowance for working capital:

1. Use a default allowance approach; or
2. The filing of a lead/lag study.

PUC has used the default allowance of 7.5% for the 2023 Test Year in this Application, in accordance with the Filing Requirements. Accordingly, PUC did not conduct a lead / lag study.

2.5.2 Working Capital Allowance

PUC is proposing a working capital allowance of $5,657,302 as shown in Table 2-21 below.

[1] OEB Letter, June 3, 2015, Allowance for Working Capital for Electricity Distribution Rate Applications

Table 2-21: Working Capital Allowance

Description		2023 Test
Distribution Expenses - Operations		$4,434,334
Distribution Expenses - Maintenance		$2,901,131
Billing & Collecting		$1,290,441
Community Relations		$753,359
Admin & General Expense		$4,154,436
Donations - LEAP		$31,130
Taxes Other than Income Taxes		$384,446
Total Eligible Distribution Expenses		**$13,949,277**
Power Supply Expenses		$61,481,413
Total Working Capital Expenses		**$75,430,690**
Working Capital Allowance @ 7.5%		**$5,657,302**

In Table 2-22 below, PUC has shown Chapter 2 Appendices 2-ZB which breaks down the power supply expenses in the Working Capital Allowance table above. The power supply expenses include electricity commodity, global adjustment, uniform transmission rates, smart meter entity charge, wholesale market service charge, Class A and B capacity based recovery, rural remote rate protection and PUC's updated rate rider for embedded generation adjustment.

Table 2-22: Power Supply Expense 2023 Test Year

		2023 Test Year	RPP		2023 Test Year	non-RPP		Total
Electricity Commodity	Units	Volume	Rate	$	Volume	Rate	$	$
Class per Load Forecast								
Residential	kWh	283,912,095		29,396,258	3,519,514		118,784	
GS < 50	kWh	70,079,044		7,255,984	12,624,665		426,082	
GS > 50	kW	42,755,086		4,426,862	188,926,311		6,376,263	
Embedded Distributor		0		-	0		-	
Street Light	kW	135,706		14,051	2,437,941		82,280	
Sentinel Light	kW	202,796		20,998	0		-	
USL	kWh	919,116		95,165	0		-	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
		0		-	0		-	
SUB-TOTAL				41,209,318			7,003,409	$ 48,212,727

Global Adjustment non-RPP	Units							
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential - Class B	kWh			0			242,072	
GS < 50 - Class B	kWh			0			868,324	
GS > 50 - Class B	kW			0			10,273,169	
Embedded Distributor - Class B				0			-	
Street Light - Class B	kW			0			167,682	
Sentinel Light - Class B	kW			0			-	
USL - Class B	kWh			0			-	
				0			-	
				0			-	
				0			-	
				0			-	
Customer A - Class A				0			392,992	
Customer B - Class A				0			1,097,367	
Customer C - Class A				0			72,685	
Customer D - Class A				0			299,321	
Customer E - Class A				0			337,190	
SUB-TOTAL				0			13,750,802	$ 13,750,802

Transmission - Network								
Class per Load Forecast		Volume	Rate	$	Volume	Rate	$	Total
Residential	kWh	283,912,095	0.0084	2,384,862	3,519,514	0.0084	29,564	
GS < 50	kWh	70,079,044	0.0078	546,617	12,624,665	0.0078	98,472	
GS > 50	kW	101,072	3.1660	319,993	111,654	3.1660	353,496	
GS>50 Interval Metered	kW				334,962	3.9826	1,334,019	
Embedded Distributor						-	-	
Street Light	kW	380	2.3886	907	6,820	2.3886	16,291	
Sentinel Light	kW	566	2.4003	1,359	-	2.4003	-	
USL	kWh	919,116	0.0078	7,169	-	0.0078	-	
							-	
							-	
							-	
							-	
SUB-TOTAL				3,260,906			1,831,843	5,092,749

Wholesale Market Service								
Class per Load Forecast							$	Total
Residential	kWh	283,912,095	0.0030	851,736	3,519,514	0.0030	10,559	
GS < 50	kWh	70,079,044	0.0030	210,237	12,624,665	0.0030	37,874	
GS > 50	kWh	42,755,086	0.0030	128,265	188,926,311	0.0030	566,779	
Embedded Distributor		-	0.0030	-	-	0.0030	-	
Street Light	kWh	135,706	0.0030	407	2,437,941	0.0030	7,314	
Sentinel Light	kWh	202,796	0.0030	608	-	0.0030	-	
USL	kWh	919,116	0.0030	2,757	-	0.0030	-	
							-	
							-	
							-	
							-	
SUB-TOTAL				1,194,012			622,525	1,816,537

Class A CBR								
Class per Load Forecast							$	Total
Residential	kWh		0.0004			0	-	
GS < 50	kWh		0.0004			0	-	
GS > 50	kWh		0.0004		39,583,764	0.0004	15,834	
Embedded Distributor			0.0004			0	-	
Street Light	kW		0.0004			0	-	
Sentinel Light	kW		0.0004			0	-	
USL	kWh		0.0004			0	-	
							-	
							-	
							-	
							-	
SUB-TOTAL							15,834	15,834

Class B CBR								
Class per Load Forecast							$	Total
Residential	kWh	283,912,095	0.0004	113,565	3,519,514	0.0004	1,408	
GS < 50	kWh	70,079,044	0.0004	28,032	12,624,665	0.0004	5,050	
GS > 50	kWh	42,755,086	0.0004	17,102	149,342,547	0.0004	59,737	
Embedded Distributor	kWh	-	0.0004	-	-	0.0004	-	
Street Light	kWh	135,706	0.0004	54	2,437,941	0.0004	975	
Sentinel Light	kWh	202,796	0.0004	81	-	0.0004	-	
USL	kWh	919,116	0.0004	368	-	0.0004	-	
							-	
							-	
							-	
							-	
SUB-TOTAL				159,202			67,170	226,371

RRRP								
Class per Load Forecast							$	Total
Residential	kWh	283,912,095	0.0005	141,956	3,519,514	0.0005	1,760	
GS < 50	kWh	70,079,044	0.0005	35,040	12,624,665	0.0005	6,312	
GS > 50	kWh	42,755,086	0.0005	21,378	188,926,311	0.0005	94,463	
Embedded Distributor		-	0.0005	-	-	0.0005	-	
Street Light	kWh	135,706	0.0005	68	2,437,941	0.0005	1,219	
Sentinel Light	kWh	202,796	0.0005	101	-	0.0005	-	
USL	kWh	919,116	0.0005	460	-	0.0005	-	
							-	
							-	
							-	
							-	
SUB-TOTAL				199,002			103,754	302,756
Rate Rider for Embedded Generation Adjustment								
Class per Load Forecast							$	Total
Residential	kWh	271,374,589	(0.0005)	(135,687)	3,364,092	(0.0005)	(1,682)	
GS < 50	kWh	66,984,366	(0.0005)	(33,492)	12,067,162	(0.0005)	(6,034)	
GS > 50	kWh	40,867,029	(0.0005)	(20,434)	180,583,360	(0.0005)	(90,292)	
Embedded Distributor		-	(0.0005)	-	-	(0.0005)	-	
Street Light	kWh	129,713	(0.0005)	(65)	2,330,282	(0.0005)	(1,165)	
Sentinel Light	kWh	193,841	(0.0005)	(97)	-	(0.0005)	-	
USL	kWh	878,528	(0.0005)	(439)	-	(0.0005)	-	
							-	
							-	
							-	
							-	
SUB-TOTAL				(190,214)			(99,172)	(289,386)
Smart Meter Entity Charge								
Class per Load Forecast							$	Total
Residential		30,340	0.43	156,554			-	
GS < 50		3,400	0.43	17,544			-	
							-	
							-	
							-	
							-	
							-	
							-	
SUB-TOTAL				174,098			-	174,098
SUB- TOTAL				46,006,323			23,296,165	69,302,488
OER CREDIT	17%			(7,821,075)			0	(7,821,075)
TOTAL				**38,185,248**			**23,296,165**	**61,481,413**

2.6 DISTRIBUTION SYSTEM PLAN

PUC has prepared a Consolidated Distribution System Plan ("DSP") in accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Transmission and Distribution Applications. PUC engaged the consulting services of METSCO to assist with the completion of its DSP for the 2023-2027 period. METSCO previously completed PUC's 2018 DSP. A snapshot of the 5-year spending by OEB category is presented in Table 2-23 with the full DSP attached as Appendix C.

Table 2-23 Distribution System Plan Summary 2023-2027

	2023 (Rebase)	2024	2025	2026	2027	2023-2027
System Access	$1,784,499	$2,094,973	$2,189,909	$1,922,788	$1,774,549	$9,766,718
System Renewal	$4,561,466	$4,200,494	$3,401,959	$3,507,494	$2,525,099	$18,196,511
System Service	$3,190,371	$127,255	$841,410	$750,095	$5,859,012	$10,768,143
General Plant	$577,035	$813,499	$1,033,414	$432,092	$633,454	$3,489,495
Totals	$10,113,371	$7,236,221	$7,466,692	$6,612,468	$10,792,114	$42,220,867

2.7 POLICY OPTIONS FOR THE FUNDING OF CAPITAL

On September 18, 2014, the Board released the *"Report of the Board New Policy Options for the Funding of Capital Investments: The Advanced Capital Module"* wherein the Board established a mechanism to assist distributors in aligning capital expenditure timing and prioritization with rate predictability and smoothing.

At this time, PUC has not planned for any ACM or ICM over the 2023-2027 period.

2.8 ADDITION OF PREVIOUSLY APPROVED ACM and ICM PROJECT ASSETS TO RATE BASE

PUC had 2 ICM applications over the period 2018-2021; Sub 16 (EB-2019-0170) and SSG (EB-2018-0219/2020-0249). PUC has included the actual project value for Sub 16 in 2022 Fixed Assets ("FA") continuity and the proposed spending of the SSG project in 2022 FA continuity. By including both projects in 2022 rate base, it ensures that the full amount is included in 2023 rate base. A full reconciliation is provided for each ICM in the paragraphs below.

2.8.1 Substation 16 (EB-2019-0170)

In 2019 PUC submitted an ICM to the OEB for the rebuild of Substation 16 ("Sub-16) as part of its 2020 IRM rate application with an expected completion date within the 2020 calendar year. The Sub 16 ICM was approved for the amount of $4,728,229, yielding a rate rider for the collection of $237,816 from customers until April 30, 2022. After thoughtful consideration of the impacts related to the COVID-19 pandemic, including worker safety and logistics of project completion, PUC decided to delay construction. Ultimately, the project was substantially completed in 2021 at a revised total cost of $6,020,119, a variance of $1,291,890 from the ICM submission. Table 2-24 below summarizes the additional expenditures.

Table 2-24: Variance Analysis ICM Costs

Variance Analysis to OEB ICM Costs	Variance
Construction Tender	$608k
Environmental Cleanup	$160k
Duct Banks and Road Restoration	$327k
COVID Related Expenses	$176k
Multiple Small Miscellaneous	$20k
Total	$1.29M

The construction of Sub 16 was tendered provincially via multiple public platforms. Several proponents submitted interest in the project and attended the tender site visit. Four submissions were received and analyzed. The lowest bidder met all requirements for the project and was therefore awarded the project. The lowest bidder's price was $608k higher than the estimated construction cost that was part of the OEB ICM submission.

During demolition of the original substation transformer oil was found in the ground that needed remediation. The associated costs for this unforeseen environmental cleanup were $160,000.

The design of the distribution lines near Sub 16 was completed after the ICM submission to the OEB. As such, previous station duct bank rebuild costs were used for the estimate. The actual design, which also includes two road crossings, verified riser cable locations and resulted in additional road, driveway, and Hub Trail restoration costs than anticipated. The station riser cable duct bank costs were $327,000 higher than what was estimated as part of the ICM submission. The project was delayed one year due to COVID-19, which resulted in additional costs of $176,000 for labour and material cost increases, as well as unanticipated equipment storage and handling expenditures.

As part of the ICM submission PUC discussed options for the rebuild of Sub 16. These options were revisited, and another option was to rehabilitate for another 5 years and then rebuild with a new station. In 2019, this yielded an estimated project cost of $7,701,716 which is higher than the $6,020,119 project actual cost. Additionally, given the higher inflation and supply chain constraints, the cost to rebuild the station now would be significantly higher. PUC is therefore requesting the full $6,020,119 to be included in 2022 rate base and submits the following revenue requirement reconciliation below in Table 2-25.

Table 2-25: Sub 16 Revenue Requirement Reconciliation

	2020	2021	2022	Total
Approved Revenue Requirement ($4.73M)	$237,816	$237,816	$237,816	$713,447
Revised Revenue Requirement ($6.02M)		$356,932	$356,932	$713,865
Projected Revenue Collection to April 30, 2023	$219,497	$283,220	$210,389	$713,107
			Refund (-) or Collection	**$ 341**

PUC used the 2020_ACM_ICM_Model to recalculate the revenue requirement base on an in-service date of 2021. The original model had a total project spend of $4,728,229 with a collection of $237,816 in revenue over 3 years. The updated model uses the actual spend of $6,020,119 and a collection of $356,932 over 2 years. As shown in the table above, PUC projects to collect $713,107 resulting in an under collection of $341.

The 2020 rate rider calculation includes a full year of depreciation and CCA. When the assets were put into service in 2021, depreciation was recorded in the 1508 other regulatory assets – depreciation using the half-year rule. Therefore, PUC has revised the ICM Model to recalculate the project revenue requirement on the originally proposed $4,728,229 project cost to update the depreciation and CCA to align with the half-year rule. Table 2-25 is revised to reflect this change, presented below in table 2-25A.

Table 2-25A: Sub 16 Revenue Requirement Reconciliation

	2020	2021	2022	Total
Approved Revenue Requirement ($4.73M)	$213,870	$237,816	$237,816	$689,502
Revised Revenue Requirement ($6.02M)		$356,932	$356,932	$713,865
Projected Revenue Collection to April 30, 2023	$219,497	$283,220	$210,389	$713,107
			Refund (-) or Collection	**$ (23,605)**

Taking this adjustment into consideration, PUC has over collected $23,605. This amount falls below the materiality threshold and PUC is not proposing to reconcile this amount through a Group 2 Account disposition.

The revised ICM model that forms the basis of the calculations is presented in Table 2-26 and 2-27. Table 2-28 shows the revised revenue requirement of $213,870 using a half year depreciation and CCA. The full details of the account balances in all 1508 Sub-accounts can be viewed in Exhibit 9.

Table 2-26: 2020_ACM_ICM_Model Revenue Requirement $4.73M

Ontario Energy Board

Capital Module
Applicable to ACM and ICM
PUC Distribution Inc.

Incremental Capital Adjustment **Rate Year:** 2020

Current Revenue Requirement					
Current Revenue Requirement - Total			$	19,273,165	A

Eligible Incremental Capital for ACM/ICM Recovery	Total Claim		Eligible for ACM/ICM (Full Year Prorated Amount) *(from Sheet 10b)*		
Amount of Capital Projects Claimed	$	4,728,229	$	2,602,851	B
Depreciation Expense	$	117,206	$	64,521	C
CCA	$	189,129	$	104,114	V

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base					
Incremental Capital			$	2,602,851	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$	64,521	C
Incremental Capital to be included in Rate Base (average NBV in year)			$	2,570,591	D = B - C/2
	% of capital structure				
Deemed Short-Term Debt	4.0%	E	$	102,824	G = D * E
Deemed Long-Term Debt	56.0%	F	$	1,439,531	H = D * F
	Rate (%)				
Short-Term Interest	2.29%	I	$	2,355	K = G * I
Long-Term Interest	4.12%	J	$	59,309	L = H * J
Return on Rate Base - Interest			$	61,663	M = K + L
	% of capital structure				
Deemed Equity %	40.00%	N	$	1,028,236	P = D * N
	Rate (%)				
Return on Rate Base -Equity	9.00%	O	$	92,541	Q = P * O
Return on Rate Base - Total			$	154,205	R = M + Q

Amortization Expense					
Amortization Expense - Incremental		C	$	64,521	S

Grossed up Taxes/PILs					
Regulatory Taxable Income		O	$	92,541	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$	64,521	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$	104,114	V
Incremental Taxable Income			$	52,948	W = T + U - V
Current Tax Rate	26.5%	X			
Taxes/PILs Before Gross Up			$	14,031	Y = W * X
Grossed-Up Taxes/PILs			$	19,090	Z = Y / (1 - X)

Incremental Revenue Requirement					
Return on Rate Base - Total		Q	$	154,205	AA
Amortization Expense - Total		S	$	64,521	AB
Grossed-Up Taxes/PILs		Z	$	19,090	AC
Incremental Revenue Requirement			$	237,816	AD = AA + AB + AC

Table 2-27: 2020_ACM_ICM_Model Revenue Requirement $6.02M

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

Incremental Capital Adjustment **Rate Year:** 2021

Current Revenue Requirement

Current Revenue Requirement - Total	$	19,273,165	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim	Eligible for ACM/ICM (Full Year Prorated Amount) *(from Sheet 10b)*	
Amount of Capital Projects Claimed	$ 6,020,000	$ 3,894,622	B
Depreciation Expense	$ 150,500	$ 97,366	C
CCA	$ 240,800	$ 155,785	V

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	3,894,622	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$	97,366	C
Incremental Capital to be included in Rate Base (average NBV in year)			$	3,845,939	D = B - C/2
	% of capital structure				
Deemed Short-Term Debt	4.0%	E	$	153,838	G = D * E
Deemed Long-Term Debt	56.0%	F	$	2,153,726	H = D * F
	Rate (%)				
Short-Term Interest	2.29%	I	$	3,523	K = G * I
Long-Term Interest	4.12%	J	$	88,734	L = H * J
Return on Rate Base - Interest			$	92,256	M = K + L
	% of capital structure				
Deemed Equity %	40.00%	N	$	1,538,376	P = D * N
	Rate (%)				
Return on Rate Base -Equity	9.00%	O	$	138,454	Q = P * O
Return on Rate Base - Total			$	230,710	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$	97,366	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$	138,454	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$	97,366	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$	155,785	V
Incremental Taxable Income			$	80,034	W = T + U - V
Current Tax Rate	26.5%	X			
Taxes/PILs Before Gross Up			$	21,209	Y = W * X
Grossed-Up Taxes/PILs			$	28,856	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	230,710	AA
Amortization Expense - Total	S	$	97,366	AB
Grossed-Up Taxes/PILs	Z	$	28,856	AC
Incremental Revenue Requirement		$	356,932	AD = AA + AB + AC

Table 2-28: 2020_ACM_ICM_Model Revenue Requirement $4.73M Half Year Depreciation and CCA

Incremental Capital Adjustment | **Rate Year:** | **2020**

Current Revenue Requirement				
Current Revenue Requirement - Total			$ 19,273,165	A

Eligible Incremental Capital for ACM/ICM Recovery	Total Claim		Eligible for ACM/ICM (Full Year Prorated Amount) (from Sheet 10b)	
Amount of Capital Projects Claimed	$ 4,728,229		$ 2,602,851	B
Depreciation Expense	$ 58,603		$ 32,260	C
CCA	$ 94,565		$ 52,057	V

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base				
Incremental Capital			$ 2,602,851	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$ 32,260	C
Incremental Capital to be included in Rate Base (average NBV in year)			$ 2,586,721	D = B - C/2
	% of capital structure			
Deemed Short-Term Debt	4.0%	E	$ 103,469	G = D * E
Deemed Long-Term Debt	56.0%	F	$ 1,448,564	H = D * F
	Rate (%)			
Short-Term Interest	2.29%	I	$ 2,369	K = G * I
Long-Term Interest	4.12%	J	$ 59,681	L = H * J
Return on Rate Base - Interest			$ 62,050	M = K + L
	% of capital structure			
Deemed Equity %	40.00%	N	$ 1,034,688	P = D * N
	Rate (%)			
Return on Rate Base -Equity	9.00%	O	$ 93,122	Q = P * O
Return on Rate Base - Total			$ 155,172	R = M + Q

Amortization Expense				
Amortization Expense - Incremental		C	$ 32,260	S

Grossed up Taxes/PILs				
Regulatory Taxable Income		O	$ 93,122	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$ 32,260	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$ 52,057	V
Incremental Taxable Income			$ 73,325	W = T + U - V
Current Tax Rate	26.5%	X		
Taxes/PILs Before Gross Up			$ 19,431	Y = W * X
Grossed-Up Taxes/PILs			$ 26,437	Z = Y / (1 - X)

Incremental Revenue Requirement			
Return on Rate Base - Total	Q	$ 155,172	AA
Amortization Expense - Total	S	$ 32,260	AB
Grossed-Up Taxes/PILs	Z	$ 26,437	AC
Incremental Revenue Requirement		$ 213,870	AD = AA + AB + AC

2.8.2 Sault Smart Grid (EB-2018-0219/EB-2020-0249)

On April 29, 2021, the OEB approved the amended and restated ICM application filed by PUC for new rates effective May 1, 2022. The OEB also approved the Accounting Order included in Exhibit 9 - Appendix A – Accounting Order Sault Smart Grid ICM outlining additional 1508 Sub Accounts to accommodate the NRCan grants associated with this project. PUC also was given a list of deliverables provided in Section 1.3 of Exhibit 1 of this application.

The approved ICM application included collection of a half year revenue requirement of $875,610 based on an estimated total project spend of $32,938,213 and contributions from NRCAN of $8,109,553 for a net cost of $24,828,660 for the project. At the time of filing this application, everything remains on plan, including assets in service by the end of 2022, with optimizing and additional testing to occur in the first quarter of 2023. Circumstances remain on track with respect to the funding agreement with NRCan and are within the budget approved as part of the ICM submission.

Since there is a small portion of testing to occur in the first quarter of 2023, PUC excluded that portion of asset additions from 2022 Rate Base and included it as part of 2023 Rate Base. Table 2-29 explains the updated gross assets additions, NRCAN grant, Net Additions, In Service Date, and Revised Revenue Requirement calculations from project approval.

Table 2-29: SSG ICM Reconciliation

	Original Submission	2022 Capital Additions (ICM)	2023 Capital Additions (COS)	Revised Total Project Spend	Variance
Gross Asset Additions	$32,938,213	$28,713,347	$ 3,190,371	$ 31,903,718	$(1,034,495)
NRCan	$ 8,109,553	$ 7,355,438	$ -	$ 7,355,438	$ (754,115)
Net Additions	$24,828,660	$21,357,909	$ 3,190,371	$ 24,548,280	$ (280,380)
In Service Date	31-Dec-22	31-Dec-22	31-Mar-23		

	Revenue Requirement				Variance
Revenue Requirement	$ 875,610	$ 868,713			$ (6,897)
Projected Rate Rider Revenue		$ 852,614			
Refund (-) or Collection		$ 16,100			

The amount of NRCan grant available was reduced by $754,115 in 2022 due to a delay in timing of project approval from the resubmission of the application to, and approval from, the OEB. The amount of Federal NRCan funding available was reduced and therefore the amount allocated to PUC ended up being slightly under the original estimate of 25.00%. This resulted in PUC adjusting the Gross project spend to $31,903,718, a reduction of $1,034,495. As mentioned above, the net project spend in 2022 is now $21,357,909. PUC has calculated a revised revenue requirement using the ICM Model submitted in its original ICM application. The result is a revised half-year revenue requirement of $868,713 and can be seen in Table 2-30 below. PUC projects to collect $832,978 using its load forecast as the billing determinants for May 1, 2022 to April 30, 2023.

Table 2-30: Revised Revenue Requirement SSG

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

Incremental Capital Adjustment **Rate Year:** 2022

Current Revenue Requirement

Current Revenue Requirement - Total	$	19,273,165	A

Eligible Incremental Capital for ACM/ICM Recovery

	Total Claim	Eligible for ACM/ICM (Half Year* Prorated Amount) (from Sheet 10b)	
Amount of Capital Projects Claimed	$ 21,357,909	$ 10,678,955	B
Depreciation Expense	$ 600,448	$ 300,224	C
CCA	$ 1,708,633	$ 854,316	V

*The half year rule is applied as the distributor is scheduled to rebase in the next rate year.

ACM/ICM Incremental Revenue Requirement Based on Eligible Amount in Rate Year

Return on Rate Base

Incremental Capital			$	10,678,955	B
Depreciation Expense (prorated to Eligible Incremental Capital)			$	300,224	C
Incremental Capital to be included in Rate Base (average NBV in year)			$	10,528,843	D = B - C/2
	% of capital structure				
Deemed Short-Term Debt	4.0%	E	$	421,154	G = D * E
Deemed Long-Term Debt	56.0%	F	$	5,896,152	H = D * F
	Rate (%)				
Short-Term Interest	2.29%	I	$	9,644	K = G * I
Long-Term Interest	4.12%	J	$	242,921	L = H * J
Return on Rate Base - Interest			$	252,566	M = K + L
	% of capital structure				
Deemed Equity %	40.00%	N	$	4,211,537	P = D * N
	Rate (%)				
Return on Rate Base -Equity	9.00%	O	$	379,038	Q = P * O
Return on Rate Base - Total			$	631,604	R = M + Q

Amortization Expense

Amortization Expense - Incremental	C	$	300,224	S

Grossed up Taxes/PILs

Regulatory Taxable Income		O	$	379,038	T
Add Back Amortization Expense (Prorated to Eligible Incremental Capital)		S	$	300,224	U
Deduct CCA (Prorated to Eligible Incremental Capital)			$	854,316	V
Incremental Taxable Income			-$	175,054	W = T + U - V
Current Tax Rate	26.5%	X			
Taxes/PILs Before Gross Up			-$	46,389	Y = W * X
Grossed-Up Taxes/PILs			-$	63,115	Z = Y / (1 - X)

Incremental Revenue Requirement

Return on Rate Base - Total	Q	$	631,604	AA
Amortization Expense - Total	S	$	300,224	AB
Grossed-Up Taxes/PILs	Z	-$	63,115	AC
Incremental Revenue Requirement		$	868,713	AD = AA + AB + AC

Since PUC is projected to over collect $23,605 for Sub 16 and under collect $16,100 from customers, the net balance is deemed to be immaterial, and PUC will not be seeking the recovery for the difference.

2.9 CAPITALIZATION POLICY

2.9.1 Capitalization Policy - IFRS

PUC follows Generally Accepted Accounting Principles, in particular the CICA Handbook *IAS 16 Property, Plant and Equipment* and the *OEB Accounting Procedure Handbook.* PUC has not made any changes to its capitalization policy since the last rebasing period.

A capital expenditure is defined as any significant expenditure incurred to acquire or improve land, buildings, plant, engineered structures, machinery and equipment used in providing services to customers. Improvement or "betterment" includes increasing capacity, reliability, efficiency, or economy of operation or extending the useful life of a previous capital expenditure. It includes electric plant, vehicles, office furniture, computer equipment and other equipment. A capital expenditure normally provides a benefit lasting beyond one year and results in the acquisition of or extends the life of a fixed asset.

Components of Property, Plant and Equipment ("PP&E") are determined, and depreciation is calculated separately for each significant component or part. Component accounting is required if the useful life and/or depreciation method for the component is different from the remainder of the asset.

Depreciation is based on the asset costs (or revalued cost) less its residual value over the estimated useful life. Estimates of residual values reflect prices at the reporting date given the condition the asset is expected to be in at the end of the useful life. Inflationary effects are not taken into account when determining the residual value. Estimates of useful life and residual value, and the method of depreciation, are reviewed at least each annual reporting date or where expectations differ from previous estimates.

The depreciation method selected is one that most closely reflects the pattern in which the asset's future economic benefits are expected to be consumed by the entity over its estimated useful life.

Directly attributed costs should be included in measuring the initial cost of an asset recognized in property, plant, and equipment. General overhead and administrative costs are specifically excluded from the cost of the asset.

Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not a capital expenditure but are charged to an operating account. Table 2-31 below provides the definition and accounting treatment for the various expenditures.

Table 2-31: Accounting Treatment and Definition of Capital Expenditure

	Definition	**Accounting Treatment**
Capital Expenditure	An expenditure to acquire or add to a capital asset – an expenditure yielding enduring benefits	Capitalize if above the materiality limit
Improvement	An expenditure made for the purpose of enhancing a fixed asset and which is an addition to the cost of the asset	Capitalize if above the materiality limit
Maintenance	The cost of keeping a property in efficient working condition	Current operations expense
Repair	The cost of replacement of parts or other restoration of plant and machinery, designed to restore normal working efficiency	Current operations expense

The following are materiality limits for the listed category of assets. Items with a cost less than the materiality levels as listed below should be charged to operations whether they are of a capital nature or of a repairs/maintenance nature.

Table 2-32: Materiality Limits

Account #	Description	Limit
	Electric Distribution	
1705, 1805, 1905	Land	All
1706, 1806, 1906	Land Right	$500
1708, 1808, 1908	Buildings	$500
1715, 1815	Transformer Station Equipment	$500
1820, 1825	Distribution Station Equipment	$500
1720, 1725, 1830	Poles, Towers and Fixtures	$500
1730, 1835	Lines & Feeders – O/H	$500
1735, 1840	Conduit – U/G	$500
1740, 1845	Lines & Feeders – U/G	$500
1850	Distribution Transformers	$500
1855	Services	All
1860	Meters	All
1915	General Office Equipment	$500
1920, 1925	Computer Equipment	$500
1935	Stores Warehouse Equipment	$500
1930	Rolling Stock	$500
1940, 1945	Miscellaneous Equipment	$500
1955	Communication Equipment	$500
1980	System Supervisory Equipment	$500

2.9.2 Capitalization of Overhead

As noted above, PP&E is recorded at cost – including purchase price, costs to bring the asset to the location and condition necessary to operate, etc. One of the costs explicitly prohibited from being included in the cost of an asset under IFRS is “administrative and other general overhead costs.”

As outline in Appendix D – Chapter 2 Appendices 2-D Overhead Expense, PUC currently includes the following in PP&E costs: direct labour, direct material from inventory or from a third-party vendor, and vehicle costs used to bring the asset to the location and condition necessary to operate. Direct labour costs are based on an hourly rate and the number of hours that an employee works on a specific project. Also, other payroll related costs in direct labour costs include benefits, pension, CPP, EI, etc. These costs are allocated to capital and period expenses based on the percentage of total labour dollars directly charged to each. Material from inventory or from a third party is charged directly to the asset that the material is used for. Vehicles are charged to a specific job based on an hourly rate and the number of hours the vehicle is used on the job. The hourly vehicle rate is estimated annually and periodically reviewed and trued-up to align with actual costs.

PUCS’s overhead burden rates (i.e. payroll, truck, and stores) allocated to PUC’s capitalization of costs of self-constructed assets are currently estimated at 50% of wages and allocated based on where employees charge their time (i.e. capital jobs/maintenance. There have not been any methodology changes since the last rebasing application.

2.10 COSTS OF ELIGIBLE INVESTMENTS FOR THE CONNECTION OF QUALIFYING GENERATION FACILITIES

Overview

Section 2.2.10 of the Filing Requirements contemplates that a distributor will file for provincial rate protection associated with any costs incurred to make eligible investments, as described in Section 79.1of the Ontario Energy Board Act and Regulation 330/09 ("O. Reg. 330/09") made under the Act. Costs incurred by a distributor, in accordance with cost responsibility rules in the Board's Distribution System Code for the purpose of connecting or enabling the connection of Renewable Energy Generation ("REG") facilities to its distribution system, are considered to be eligible investments for the purpose of Provincial rate recovery under Section 79.1 of the Act.

History

PUC currently has approximately 63MW of REG connected to its distribution system, which on occasion results in net export conditions during summer months when the distribution network is near its minimum load. PUC also hosts an IESO controlled 7MW/7MWh battery energy storage facility connected to St. Mary's Transformer Station 34.5kV bus.

2.10.1 Applications for REG Greater than 10kW

The connection history for all REG installations connected to the PUC distribution system over 10kW is illustrated in Table 2-33 below. Of all the applications made, those that were not connected had applications terminated by the applicant and in no cases was unavailable capacity the deciding factor.

Table 2-33: Applications for REG over 10kW

PUC Applications from Renewable Generators Over 10kW

	Application Date		Application MW		Connection Date		Connection MW	
Pre-2013	1985		0.25		1985		0.25	
	2007-04-15		9.95		2010-10-15		9.96	
	2007-04-17		9.95		2010-10-15		9.96	
	2007-06-03		9.95		2011-08-30		9.96	
	2007-06-03		9.95		2011-08-30		9.96	
	2007-06-03		9.95		2011-07-27		9.96	
	2007-06-03		9.95		2011-11-22		9.96	
	2007-07-24		0.045		2008		0.045	
	2007		9.95		N/A		0	
	2007		9.95		N/A		0	
	2008-01-08		0.037		2008-07-08		0.037	
	2011-02-28		0.1		2011-06-09		0.1	
	2011-06-07		0.5		2011-07-20		0.5	
	2011-06-14		0.135		2011-11-14		0.135	
	2011-09-09		0.035		2012-11-23		0.035	
	2011-09-26		0.25		2012-08-29		0.25	
	Quantity	16	Total MW	80.952	Quantity	14	Total MW	61.112
2013	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2014	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2015	2015-02-18		0.1		2016-08-23		0.1	
	Quantity	1	Total MW	0.1	Quantity	1	Total MW	0.1
2016	2016-03-11		0.25		2017-01-06		0.25	
	2016-03-11		0.25		2017-01-06		0.25	
	2016-03-11		0.25		2017-01-06		0.25	
	2016-06-17		0.07		2016-09-29		0.07	
	Quantity	4	Total MW	0.82	Quantity	4	Total MW	0.82
2017	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2018	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2019	2019-01-04		0.087		N/A		0	
	Quantity	1	Total MW	0.087	Quantity	0	Total MW	0
2020	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2021	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2022	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2018-2022 Totals	Quantity	1	Total MW	0.087	Quantity	0	Total MW	0
Grand Total	Quantity	22	Total MW	81.959	Quantity	19	Total MW	62.032

2.10.2 Applications for REG 10kW or less

Currently there are no applications in the queue from REG connections <10kW under the Micro-FIT program and all requests for Micro-FIT generation received to date have been successfully connected to the system. There appears to be a growing interest in net metering and some discussions about that in conjunction with energy storage behind-the-meter as the gap closes between Micro-FIT contract pricing and the Residential class load energy costs.

System Capacity to Support REG

Primarily based on thermal ratings of conductors and transformers, PUC has developed and submitted to the IESO, the following table of available capacity. The IESO uses this for planning and as an input to preparing a Transmission Availability Table ("TAT") which is posted online to assist prospective REG applicants in selecting a site for their project. Table 2-34 summarizes available capacity at the 34.5kV feeder and station bus levels. The table shows that at the present time, there is capacity available for future connection of approximately 27MW more generation between circuits out of TS1 and TS2 combined.

Table 2-34: PUC Available Capacity

Station	Bus Name	Capacity (MW)	Allocated Capacity (MW)	Available Capacity (MW)	Supply Circuit 1	Supply Circuit 2
TS1 (St. Mary's)	Total	45	41.367	3.633	GL1SM	GL2SM
	West	30	21.004	3.633		
	East	30	20.363	3.633		
TS2 (Tarentorus)	Total	45	21.648	23.352	GL1TA	GL2TA
	West	30	21.001	8.999		
	East	30	0.647	23.352		

34.5 kV Feeder Name	Bus Connection	Capacity (MW)	Allocated Capacity	Available Capacity (MW)	Notes:
SM-5	West	30	10.214	3.633	TS Limiting (45-D5) MW
SM-7	West	30	9.960	3.633	TS Limiting (45-D5) MW
Sub 19 West	West	N/A	0.829	N/A	no feeder, direct bus connection
SM-9	East	30	10.044	3.633	TS Limiting (45-D5) MW
SM-11	East	30	10.061	3.633	TS Limiting (45-D5) MW
Sub 19 East	East	N/A	0.259	N/A	no feeder, direct bus connection
TS1			**41.367**		
TA-6	West	30	0.125	23.352	TS Limiting (45-D8) MW
TA-7	West	30	20.876	8.999	West Bus Limiting (30-D9) MW
TA-9	East	30	0.028	23.352	TS Limiting (45-D8) MW
TA-10	East	30	0.188	23.352	TS Limiting (45-D8) MW
TA-11	East	30	0.431	23.352	TS Limiting (45-D8) MW
TS2			**21.648**		

Proposed Plan and Investments to Support REG

The PUC grid is presently very well positioned to support all forecasted REG connections over the next five years and no associated infrastructure investment is required during that period.

Please see Appendix E – App 2-FA Proposed REG Invest, Appendix F - App 2 FB Calc of REG Improvement and Appendix G – App 2 2-FC Calc of REG Expansion which indicate there are no eligible investments for recovery.

APPENDIX A

Fixed Asset

Continuity Schedule

Board Appendix 2-BA

Accounting Standard MIFRS
Year **2018**

		Cost					Accumulated Depreciation				
OEB Account [3]	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**RRR DATA**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
1706	Land Rights	$ 602,307			$ 602,307		$ -	$ -		$ -	$ 602,307
1725	Poles and Fixtures	$ 1,604,339			$ 1,604,339		$ 156,521	$ 39,130		$ 195,651	$ 1,408,688
1730	Overhead Conductors & Devices	$ 63,894			$ 63,894		$ 7,987	$ 1,997		$ 9,983	$ 53,911
1735	Underground Conduit	$ 870,020			$ 870,020		$ 99,431	$ 24,858		$ 124,289	$ 745,732
1740	Underground Conductors & Devices	$ 215,252			$ 215,252		$ 39,137	$ 9,784		$ 48,921	$ 166,331
1609	Capital Contributions Paid				$ -	$ -				$ -	$ -
1611	Computer Software (Formally known as Account 1925)				$ -	$ -				$ -	$ -
1612	Land Rights (Formally known as Account 1906)				$ -	$ 189,356				$ -	$ -
1805	Land	$ 89,160	$ -	-$ 32,744	$ 56,415	$ 56,415				$ -	$ 56,415
1806	Land Rights	$ 178,951	$ 10,405		$ 189,356					$ -	$ 189,356
1808	Buildings	$ 25,027,092	$ 8,455		$ 25,035,547	$ 25,035,547	$ 2,717,413	$ 683,038		$ 3,400,451	$ 21,635,096
1810	Leasehold Improvements				$ -	$ -				$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 7,662,606	$ 292,263		$ 7,954,869	$ 7,954,869	$ 1,000,670	$ 286,747		$ 1,287,417	$ 6,667,452
1820	Distribution Station Equipment <50 kV	$ 10,510,642	$ 338,454		$ 10,849,096	$ 10,849,096	$ 1,597,765	$ 426,800		$ 2,024,565	$ 8,824,531
1825	Storage Battery Equipment	$ 13,722	$ -		$ 13,722	$ 13,722	$ 2,614	$ 653		$ 3,267	$ 10,455
1830	Poles, Towers & Fixtures	$ 17,808,103	$ 1,743,944		$ 19,552,048	$ 19,552,048	$ 1,301,617	$ 420,389		$ 1,722,005	$ 17,830,043
1835	Overhead Conductors & Devices	$ 12,985,479	$ 953,873		$ 13,939,351	$ 13,939,351	$ 1,073,638	$ 317,104		$ 1,390,742	$ 12,548,610
1840	Underground Conduit	$ 3,662,059	$ 405,688		$ 4,067,747	$ 4,067,747	$ 897,887	$ 238,547		$ 1,136,434	$ 2,931,313
1845	Underground Conductors & Devices	$ 13,447,279	$ 311,100		$ 13,758,378	$ 13,758,378	$ 2,105,522	$ 551,408		$ 2,656,931	$ 11,101,447
1850	Line Transformers	$ 13,256,636	$ 722,098		$ 13,978,734	$ 13,978,734	$ 1,130,181	$ 346,378		$ 1,476,559	$ 12,502,175
1855	Services (Overhead & Underground)	$ 6,076,631	$ 577,442		$ 6,654,074	$ 6,654,074	$ 583,072	$ 166,936		$ 750,009	$ 5,904,065
1860	Meters	$ 4,838,566	$ 145,913		$ 4,984,479	$ 4,984,479	$ 1,678,254	$ 435,774		$ 2,114,028	$ 2,870,451
1860	Meters (Smart Meters)				$ -	$ 4,984,479				$ -	$ -
1905	Land				$ -	$ -				$ -	$ -
1908	Buildings & Fixtures				$ -	$ -				$ -	$ -
1910	Leasehold Improvements				$ -	$ -				$ -	$ -
1915	Office Furniture & Equipment (10 years)				$ -	$ -				$ -	$ -
1915	Office Furniture & Equipment (5 years)				$ -	$ -				$ -	$ -
1920	Computer Equipment - Hardware				$ -	$ -				$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -	$ -				$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)				$ -	$ -				$ -	$ -
1930	Transportation Equipment				$ -	$ -				$ -	$ -
1935	Stores Equipment				$ -	$ -				$ -	$ -
1940	Tools, Shop & Garage Equipment				$ -	$ -				$ -	$ -
1945	Measurement & Testing Equipment				$ -	$ -				$ -	$ -
1950	Power Operated Equipment				$ -	$ -				$ -	$ -
1955	Communications Equipment				$ -	$ -				$ -	$ -
1955	Communication Equipment (Smart Meters)				$ -	$ -				$ -	$ -
1960	Miscellaneous Equipment				$ -	$ -				$ -	$ -
1970	Load Management Controls Customer Premises				$ -	$ -				$ -	$ -
1975	Load Management Controls Utility Premises				$ -	$ -				$ -	$ -
1980	System Supervisor Equipment	$ 1,600,673	$ 66,076		$ 1,666,749	$ 1,666,749	$ 952,647	$ 242,873		$ 1,195,521	$ 471,228
1985	Miscellaneous Fixed Assets				$ -	$ -				$ -	$ -
1990	Other Tangible Property				$ -	$ -				$ -	$ -
1995	Contributions & Grants	-$ 11,161,739	$ -		-$ 11,161,739	-$ 14,446,706	-$ 1,313,146	-$ 328,286		-$ 1,641,432	-$ 9,520,307
2440	Deferred Revenue[5]	-$ 3,087,531	-$ 431,033		-$ 3,518,564	$ -	-$ 151,021	-$ 82,576		-$ 233,597	-$ 3,284,967
2005	Property Under Finance Lease[7]				$ -	$ -				$ -	$ -
	Sub-Total	**$ 106,264,142**	**$ 5,144,679**	**-$ 32,744**	**$ 111,376,076**	**$ 113,238,339**	**$ 13,880,189**	**$ 3,781,554**	**$ -**	**$ 17,661,743**	**$ 93,714,333**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -					$ -	$ -
	Total PP&E	**$ 106,264,142**	**$ 5,144,679**	**-$ 32,744**	**$ 111,376,076**		**$ 13,880,189**	**$ 3,781,554**	**$ -**	**$ 17,661,743**	**$ 93,714,333**
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
	Total							**$ 3,781,554**			

Less: *Fully Allocated Depreciation*

	Transportation	Transportation	
	Stores Equipment	Stores Equipment	
	Deferred Revenue	Deferred Revenue	-$ 82,576
		Net Depreciation	**$ 3,864,131**

Accounting Standard	MIFRS
Year	**2019**

		Cost					Accumulated Depreciation				
OEB Account [3]	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**Closing Balance**	**RRR DATA**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**Closing Balance**	**Net Book Value**
1706	Land Rights	$ 602,307			$ 602,307		$ -			$ -	$ 602,307
1725	Poles and Fixtures	$ 1,604,339			$ 1,604,339		$ 195,651	$ 39,130		$ 234,781	$ 1,369,558
1730	Overhead Conductors & Devices	$ 63,894			$ 63,894		$ 9,983	$ 1,997		$ 11,980	$ 51,914
1735	Underground Conduit	$ 870,020			$ 870,020		$ 124,289	$ 24,858		$ 149,146	$ 720,874
1740	Underground Conductors & Devices	$ 215,252			$ 215,252		$ 48,921	$ 9,784		$ 58,705	$ 156,547
1609	Capital Contributions Paid	$ -			$ -	$ -	$ -			$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -	$ -			$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ 189,356	$ -			$ -	$ -
1805	Land	$ 56,415			$ 56,415	$ 56,415	$ -			$ -	$ 56,415
1806	Land Rights	$ 189,356	$ 14,311		$ 203,667		$ -			$ -	$ 203,667
1808	Buildings	$ 25,035,547	$ 177,803		$ 25,213,351	$ 25,035,547	$ 3,400,451	$ 686,763		$ 4,087,214	$ 21,126,136
1810	Leasehold Improvements	$ -			$ -	$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 7,954,869	$ 233,949		$ 8,188,818	$ 7,954,869	$ 1,287,417	$ 293,325		$ 1,580,742	$ 6,608,076
1820	Distribution Station Equipment <50 kV	$ 10,849,096	$ 226,273		$ 11,075,369	$ 10,849,096	$ 2,024,565	$ 433,859		$ 2,458,424	$ 8,616,944
1825	Storage Battery Equipment	$ 13,722			$ 13,722	$ 13,722	$ 3,267	$ 653		$ 3,920	$ 9,801
1830	Poles, Towers & Fixtures	$ 19,552,048	$ 2,058,945		$ 21,610,992	$ 19,552,048	$ 1,722,005	$ 462,643		$ 2,184,648	$ 19,426,344
1835	Overhead Conductors & Devices	$ 13,939,351	$ 646,542		$ 14,585,893	$ 13,939,351	$ 1,390,742	$ 330,441		$ 1,721,182	$ 12,864,711
1840	Underground Conduit	$ 4,067,747	$ 494,913		$ 4,562,660	$ 4,067,747	$ 1,136,434	$ 247,553		$ 1,383,987	$ 3,178,674
1845	Underground Conductors & Devices	$ 13,758,378	$ 314,478		$ 14,072,856	$ 13,758,378	$ 2,656,931	$ 559,228		$ 3,216,159	$ 10,856,697
1850	Line Transformers	$ 13,978,734	$ 898,402		$ 14,877,136	$ 13,978,734	$ 1,476,559	$ 367,055		$ 1,843,614	$ 13,033,522
1855	Services (Overhead & Underground)	$ 6,654,074	$ 536,808		$ 7,190,881	$ 6,654,074	$ 750,009	$ 190,040		$ 940,049	$ 6,250,832
1860	Meters	$ 4,984,479	$ 76,616		$ 5,061,095	$ 4,984,479	$ 2,114,028	$ 443,191		$ 2,557,219	$ 2,503,876
1860	Meters (Smart Meters)	$ -			$ -	$ 4,984,479	$ -			$ -	$ -
1905	Land	$ -			$ -	$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ -			$ -	$ -	$ -			$ -	$ -
1910	Leasehold Improvements	$ -			$ -	$ -	$ -			$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -	$ -			$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ -			$ -	$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1935	Stores Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1945	Measurement & Testing Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1950	Power Operated Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ 1,666,749	$ 156,497		$ 1,823,246	$ 1,666,749	$ 1,195,521	$ 248,438		$ 1,443,958	$ 379,288
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -	$ -			$ -	$ -
1995	Contributions & Grants	-$ 11,161,739			-$ 11,161,739	$ -	-$ 1,641,432	-$ 328,286		-$ 1,969,719	-$ 9,192,021
2440	Deferred Revenue[5]	-$ 3,518,564	-$ 1,111,843		-$ 4,630,407	$ -	-$ 233,597	-$ 101,862		-$ 335,459	-$ 4,294,948
2005	Property Under Finance Lease[7]				$ -	$ -	0			$ -	$ -
	Sub-Total	**$ 111,376,076**	**$ 4,723,694**	**$ -**	**$ 116,099,770**	**$ 127,685,045**	**$ 17,661,743**	**$ 3,908,810**	**$ -**	**$ 21,570,553**	**$ 94,529,217**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -					$ -	$ -
	Total PP&E	**$ 111,376,076**	**$ 4,723,694**	**$ -**	**$ 116,099,770**		**$ 17,661,743**	**$ 3,908,810**	**$ -**	**$ 21,570,553**	**$ 94,529,217**
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
	Total							**$ 3,908,810**			

		Less: *Fully Allocated Depreciation*	
	Transportation	Transportation	
	Stores Equipment	Stores Equipment	
	Deferred Revenue	Deferred Revenue	-$ 101,862
		Net Depreciation	**$ 4,010,672**

Accounting Standard	MIFRS
Year	**2020**

OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Cost: RRR DATA	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Closing Balance	Net Book Value
1706	Land Rights	$ 602,307			$ 602,307		$ -			$ -	$ 602,307
1725	Poles and Fixtures	$ 1,604,339			$ 1,604,339		$ 234,781	$ 39,130		$ 273,912	$ 1,330,428
1730	Overhead Conductors & Devices	$ 63,894			$ 63,894		$ 11,980	$ 1,997		$ 13,977	$ 49,917
1735	Underground Conduit	$ 870,020			$ 870,020		$ 149,146	$ 24,858		$ 174,004	$ 696,016
1740	Underground Conductors & Devices	$ 215,252			$ 215,252		$ 58,705	$ 9,784		$ 68,489	$ 146,763
1609	Capital Contributions Paid	$ -			$ -	$ -	$ -			$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -	$ -			$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ 189,356	$ -			$ -	$ -
1805	Land	$ 56,415			$ 56,415	$ 56,415	$ -			$ -	$ 56,415
1806	Land Rights	$ 203,667	$ 14,268		$ 217,935		$ -			$ -	$ 217,935
1808	Buildings	$ 25,213,351	$ 125,719		$ 25,339,070	$ 25,035,547	$ 4,087,214	$ 692,833		$ 4,780,048	$ 20,559,022
1810	Leasehold Improvements	$ -			$ -	$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 8,188,818	$ 184,850		$ 8,373,668	$ 7,954,869	$ 1,580,742	$ 298,560		$ 1,879,302	$ 6,494,366
1820	Distribution Station Equipment <50 kV	$ 11,075,369	$ 531,294		$ 11,606,662	$ 10,849,096	$ 2,458,424	$ 443,329		$ 2,901,753	$ 8,704,909
1825	Storage Battery Equipment	$ 13,722			$ 13,722	$ 13,722	$ 3,920	$ 653		$ 4,574	$ 9,148
1830	Poles, Towers & Fixtures	$ 21,610,992	$ 1,797,499		$ 23,408,492	$ 19,552,048	$ 2,184,648	$ 505,492		$ 2,690,141	$ 20,718,351
1835	Overhead Conductors & Devices	$ 14,585,893	$ 783,153		$ 15,369,046	$ 13,939,351	$ 1,721,182	$ 342,355		$ 2,063,537	$ 13,305,509
1840	Underground Conduit	$ 4,562,660	$ 62,255		$ 4,624,916	$ 4,067,747	$ 1,383,987	$ 253,124		$ 1,637,111	$ 2,987,805
1845	Underground Conductors & Devices	$ 14,072,856	$ 554,440		$ 14,627,297	$ 13,758,378	$ 3,216,159	$ 570,090		$ 3,786,249	$ 10,841,048
1850	Line Transformers	$ 14,877,136	$ 953,608		$ 15,830,744	$ 13,978,734	$ 1,843,614	$ 388,011		$ 2,231,625	$ 13,599,120
1855	Services (Overhead & Underground)	$ 7,190,881	$ 392,402		$ 7,583,283	$ 6,654,074	$ 940,049	$ 197,068		$ 1,137,117	$ 6,446,167
1860	Meters	$ 5,061,095	$ 476,303		$ 5,537,398	$ 4,984,479	$ 2,557,219	$ 461,622		$ 3,018,841	$ 2,518,557
1860	Meters (Smart Meters)	$ -			$ -	$ 4,984,479	$ -			$ -	$ -
1905	Land	$ -			$ -	$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ -			$ -	$ -	$ -			$ -	$ -
1910	Leasehold Improvements	$ -			$ -	$ -	$ -			$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -	$ -			$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ -			$ -	$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1935	Stores Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1945	Measurement & Testing Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1950	Power Operated Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ 1,823,246	$ 9,935		$ 1,833,182	$ 1,666,749	$ 1,443,958	$ 252,599		$ 1,696,557	$ 136,625
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -	$ -			$ -	$ -
1995	Contributions & Grants	-$ 11,161,739			-$ 11,161,739	$ -	-$ 1,969,719	-$ 328,286		-$ 2,298,005	-$ 8,863,734
2440	Deferred Revenue[5]	-$ 4,630,407	-$ 658,166		-$ 5,288,573	$ -	-$ 335,459	-$ 123,987		-$ 459,446	-$ 4,829,126
2005	Property Under Finance Lease[7]	0			$ -	$ -	0			$ -	$ -
	Sub-Total	**$ 116,099,770**	**$ 5,227,561**	**$ -**	**$ 121,327,331**	**$ 127,685,045**	**$ 21,570,553**	**$ 4,029,231**	**$ -**	**$ 25,599,783**	**$ 95,727,548**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
	Less Other Non Rate-Regulated Utility Assets *(input as negative)*				$ -					$ -	$ -
	Total PP&E	**$ 116,099,770**	**$ 5,227,561**	**$ -**	**$ 121,327,331**		**$ 21,570,553**	**$ 4,029,231**	**$ -**	**$ 25,599,783**	**$ 95,727,548**
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
	Total							**$ 4,029,231**			

Less: *Fully Allocated Depreciation*

	Transportation	Transportation	
	Stores Equipment	Stores Equipment	
	Deferred Revenue	Deferred Revenue	-$ 123,987
		Net Depreciation	**$ 4,153,218**

Accounting Standard MIFRS
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OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: Closing Balance	Cost: RRR DATA	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: Closing Balance	Net Book Value
1706	Land Rights	$ 602,307			$ 602,307		$ -			$ -	$ 602,307
1725	Poles and Fixtures	$ 1,604,339			$ 1,604,339		$ 273,912	$ 39,130		$ 313,042	$ 1,291,298
1730	Overhead Conductors & Devices	$ 63,894			$ 63,894		$ 13,977	$ 1,997		$ 15,974	$ 47,921
1735	Underground Conduit	$ 870,020			$ 870,020		$ 174,004	$ 24,858		$ 198,862	$ 671,159
1740	Underground Conductors & Devices	$ 215,252			$ 215,252		$ 68,489	$ 9,784		$ 78,274	$ 136,979
1609	Capital Contributions Paid	$ -			$ -	$ -	$ -			$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ -			$ -	$ -	$ -			$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ 189,356	$ -			$ -	$ -
1805	Land	$ 56,415			$ 56,415	$ 56,415	$ -			$ -	$ 56,415
1806	Land Rights	$ 217,935	$ 157,463		$ 375,398		$ -			$ -	$ 375,398
1808	Buildings	$ 25,339,070	$ 584,705		$ 25,923,775	$ 25,035,547	$ 4,780,048	$ 706,421		$ 5,486,469	$ 20,437,306
1810	Leasehold Improvements	$ -			$ -	$ -	$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 8,373,668	$ 70,828		$ 8,444,495	$ 7,954,869	$ 1,879,302	$ 301,756		$ 2,181,057	$ 6,263,438
1820	Distribution Station Equipment <50 kV	$ 11,606,662	$ 575,333		$ 12,181,995	$ 10,849,096	$ 2,901,753	$ 457,162		$ 3,358,915	$ 8,823,081
1825	Storage Battery Equipment	$ 13,722			$ 13,722	$ 13,722	$ 4,574	$ 653		$ 5,227	$ 8,494
1830	Poles, Towers & Fixtures	$ 23,408,492	$ 1,574,663		$ 24,983,155	$ 19,552,048	$ 2,690,141	$ 542,961		$ 3,233,102	$ 21,750,053
1835	Overhead Conductors & Devices	$ 15,369,046	$ 507,099		$ 15,876,144	$ 13,939,351	$ 2,063,537	$ 353,107		$ 2,416,644	$ 13,459,500
1840	Underground Conduit	$ 4,624,916	$ 183,281		$ 4,808,197	$ 4,067,747	$ 1,637,111	$ 255,580		$ 1,892,691	$ 2,915,506
1845	Underground Conductors & Devices	$ 14,627,297	$ 563,813		$ 15,191,109	$ 13,758,378	$ 3,786,249	$ 584,068		$ 4,370,317	$ 10,820,793
1850	Line Transformers	$ 15,830,744	$ 772,929		$ 16,603,673	$ 13,978,734	$ 2,231,625	$ 406,873		$ 2,638,498	$ 13,965,175
1855	Services (Overhead & Underground)	$ 7,583,283	$ 592,995		$ 8,176,278	$ 6,654,074	$ 1,137,117	$ 209,385		$ 1,346,502	$ 6,829,776
1860	Meters	$ 5,537,398	$ 216,522		$ 5,753,920	$ 4,984,479	$ 3,018,841	$ 484,716		$ 3,503,557	$ 2,250,364
1860	Meters (Smart Meters)	$ -			$ -	$ 4,984,479	$ -			$ -	$ -
1905	Land	$ -			$ -	$ -	$ -			$ -	$ -
1908	Buildings & Fixtures	$ -			$ -	$ -	$ -			$ -	$ -
1910	Leasehold Improvements	$ -			$ -	$ -	$ -			$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ -			$ -	$ -	$ -			$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -	$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ -			$ -	$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -			$ -	$ -	$ -			$ -	$ -
1930	Transportation Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1935	Stores Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1945	Measurement & Testing Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1950	Power Operated Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1955	Communications Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -	$ -			$ -	$ -
1960	Miscellaneous Equipment	$ -			$ -	$ -	$ -			$ -	$ -
1970	Load Management Controls Customer Premises	$ -			$ -	$ -	$ -			$ -	$ -
1975	Load Management Controls Utility Premises	$ -			$ -	$ -	$ -			$ -	$ -
1980	System Supervisor Equipment	$ 1,833,182	$ -		$ 1,833,182	$ 1,666,749	$ 1,696,557	-$ 207,938		$ 1,488,619	$ 344,563
1985	Miscellaneous Fixed Assets	$ -			$ -	$ -	$ -			$ -	$ -
1990	Other Tangible Property	$ -			$ -	$ -	$ -			$ -	$ -
1995	Contributions & Grants	-$ 11,161,739			-$ 11,161,739	$ -	-$ 2,298,005	-$ 328,286		-$ 2,626,292	-$ 8,535,448
2440	Deferred Revenue[5]	-$ 5,288,573	-$ 641,214		-$ 5,929,786	$ -	-$ 459,446	-$ 140,229		-$ 599,676	-$ 5,330,111
2005	Property Under Finance Lease[7]	0			$ -	$ -	0			$ -	$ -
	Sub-Total	**$ 121,327,331**	**$ 5,158,416**	**$ -**	**$ 126,485,747**	**$ 127,685,045**	**$ 25,599,783**	**$ 3,701,996**	**$ -**	**$ 29,301,780**	**$ 97,183,968**
	Less Socialized Renewable Energy Generation Investments (input as negative)				$ -					$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -					$ -	$ -
	Total PP&E	**$ 121,327,331**	**$ 5,158,416**	**$ -**	**$ 126,485,747**		**$ 25,599,783**	**$ 3,701,996**	**$ -**	**$ 29,301,780**	**$ 97,183,968**
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]										
	Total							**$ 3,701,996**			

Less: *Fully Allocated Depreciation*

	Transportation	Transportation	
	Stores Equipment	Stores Equipment	
	Deferred Revenue	Deferred Revenue	-$ 140,229
		Net Depreciation	**$ 3,842,226**

		Accounting Standard	MIFRS												
		Year	**2022**												

		Cost							**Accumulated Depreciation**						
OEB Account [3]	**Description [3]**	**Opening Balance [8]**	**Additions [4]**	**Disposals [6]**	**ICM Sub 16**	**ICM SSG**	**Closing Balance**	**RRR DATA**	**Opening Balance [8]**	**Additions**	**Disposals [6]**	**ICM Sub 16**	**ICM SSG**	**Closing Balance**	**Net Book Value**
1706	Land Rights	$ 602,307					$ 602,307		$ -					$ -	$ 602,307
1725	Poles and Fixtures	$ 1,604,339					$ 1,604,339		$ 313,042	$ 39,130				$ 352,172	$ 1,252,167
1730	Overhead Conductors & Devices	$ 63,894					$ 63,894		$ 15,974	$ 1,997				$ 17,970	$ 45,924
1735	Underground Conduit	$ 870,020					$ 870,020		$ 198,862	$ 24,858				$ 223,720	$ 646,301
1740	Underground Conductors & Devices	$ 215,252					$ 215,252		$ 78,274	$ 9,784				$ 88,058	$ 127,194
1609	Capital Contributions Paid	$ -					$ -	$ -	$ -					$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ -					$ -	$ -	$ -					$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -					$ -	$ 189,356	$ -					$ -	$ -
1805	Land	$ 56,415					$ 56,415	$ 56,415	$ -					$ -	$ 56,415
1806	Land Rights	$ 375,398					$ 375,398		$ -					$ -	$ 375,398
1808	Buildings	$ 25,923,775	$ 35,828				$ 25,959,603	$ 25,035,547	$ 5,486,469	$ 719,297				$ 6,205,766	$ 19,753,837
1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 8,444,495	$ 64,636				$ 8,509,131	$ 7,954,869	$ 2,181,057	$ 303,449				$ 2,484,506	$ 6,024,625
1820	Distribution Station Equipment <50 kV	$ 12,181,995	$ 3,357,721		$ 6,020,120	$ 20,622,622	$ 42,182,458	$ 10,849,096	$ 3,358,915	$ 506,325		$ 225,754	$ 257,783	$ 4,348,777	$ 37,833,681
1825	Storage Battery Equipment	$ 13,722	$ -				$ 13,722	$ 13,722	$ 5,227	$ 653				$ 5,881	$ 7,841
1830	Poles, Towers & Fixtures	$ 24,983,155	$ 2,467,354			$ 1,092,717	$ 28,543,225	$ 19,552,048	$ 3,233,102	$ 587,872			$ 12,141	$ 3,833,115	$ 24,710,110
1835	Overhead Conductors & Devices	$ 15,876,144	$ 551,951			$ 2,118,379	$ 18,546,474	$ 13,939,351	$ 2,416,644	$ 361,932			$ 17,653	$ 2,796,230	$ 15,750,244
1840	Underground Conduit	$ 4,808,197	$ 635,945			$ -	$ 5,444,141	$ 4,067,747	$ 1,892,691	$ 263,772			$ -	$ 2,156,463	$ 3,287,678
1845	Underground Conductors & Devices	$ 15,191,109	$ 113,309			$ 1,023,106	$ 16,327,524	$ 13,758,378	$ 4,370,317	$ 592,532			$ 12,789	$ 4,975,637	$ 11,351,887
1850	Line Transformers	$ 16,603,673	$ 561,961			$ 367,369	$ 17,533,003	$ 13,978,734	$ 2,638,498	$ 423,863			$ 4,592	$ 3,066,953	$ 14,466,050
1855	Services (Overhead & Underground)	$ 8,176,278	$ 503,053				$ 8,679,331	$ 6,654,074	$ 1,346,502	$ 223,086				$ 1,569,587	$ 7,109,743
1860	Meters	$ 5,753,920	$ 173,168				$ 5,927,089	$ 4,984,479	$ 3,503,557	$ 497,706				$ 4,001,263	$ 1,925,826
1860	Meters (Smart Meters)	$ -					$ -	$ 4,984,479	$ -					$ -	$ -
1905	Land	$ -					$ -	$ -	$ -					$ -	$ -
1908	Buildings & Fixtures	$ -					$ -	$ -	$ -					$ -	$ -
1910	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ -					$ -	$ -	$ -					$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -	$ -					$ -	$ -
1920	Computer Equipment - Hardware	$ -					$ -	$ -	$ -					$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -	$ -					$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
1930	Transportation Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1935	Stores Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1940	Tools, Shop & Garage Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1945	Measurement & Testing Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1950	Power Operated Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1955	Communications Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -					$ -	$ -	$ -					$ -	$ -
1960	Miscellaneous Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1970	Load Management Controls Customer Premises	$ -					$ -	$ -	$ -					$ -	$ -
1975	Load Management Controls Utility Premises	$ -					$ -	$ -	$ -					$ -	$ -
1980	System Supervisor Equipment	$ 1,833,182				$ 3,489,154	$ 5,322,336	$ 1,666,749	$ 1,488,619	$ 22,579			$ 87,229	$ 1,598,426	$ 3,723,909
1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
1995	Contributions & Grants	-$ 11,161,739					-$ 11,161,739	$ -	-$ 2,626,292	-$ 328,286				-$ 2,954,578	-$ 8,207,161
2440	Deferred Revenue[5]	-$ 5,929,786	-$ 492,800			-$ 7,355,438	-$ 13,778,024	$ -	-$ 599,676	-$ 154,405			-$ 91,943	-$ 846,023	-$ 12,932,001
2005	Property Under Finance Lease[7]	0					$ -	$ -	0					$ -	$ -
	Sub-Total	**$ 126,485,747**	**$ 7,972,124**	**$ -**	**$ 6,020,120**	**$ 21,357,909**	**$ 161,835,900**	**$ 127,685,045**	**$ 29,301,780**	**$ 4,096,144**	**$ -**	**$ 225,754**	**$ 300,244**	**$ 33,923,922**	**$ 127,911,978**
	Less Socialized Renewable Energy Generation Investments (input as negative)						$ -							$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -							$ -	$ -
	Total PP&E	**$ 126,485,747**	**$ 7,972,124**	**$ -**	**$ 6,020,120**	**$ 21,357,909**	**$ 161,835,900**		**$ 29,301,780**	**$ 4,096,144**	**$ -**	**$ 225,754**	**$ 300,244**	**$ 33,923,922**	**$ 127,911,978**
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
	Total									**$ 4,622,143**					

		Less: *Fully Allocated Depreciation*	
	Transportation	Transportation	
	Stores Equipment	Stores Equipment	
	Deferred Revenue	Deferred Revenue	-$ 246,348
		Net Depreciation	**$ 4,868,490**

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Year 2023

OEB Account [3]	Description [3]	Cost: Opening Balance [8]	Cost: Additions [4]	Cost: Disposals [6]	Cost: ICM Sub 16	Cost: ICM SSG	Cost: Closing Balance	Cost: RRR DATA	Accumulated Depreciation: Opening Balance [8]	Accumulated Depreciation: Additions	Accumulated Depreciation: Disposals [6]	Accumulated Depreciation: ICM Sub 16	Accumulated Depreciation: ICM SSG	Accumulated Depreciation: Closing Balance	Net Book Value
1706	Land Rights	$ 602,307					$ 602,307		$ -					$ -	$ 602,307
1725	Poles and Fixtures	$ 1,604,339					$ 1,604,339		$ 352,172	$ 39,130				$ 391,302	$ 1,213,037
1730	Overhead Conductors & Devices	$ 63,894					$ 63,894		$ 17,970	$ 1,997				$ 19,967	$ 43,927
1735	Underground Conduit	$ 870,020					$ 870,020		$ 223,720	$ 24,858				$ 248,577	$ 621,443
1740	Underground Conductors & Devices	$ 215,252					$ 215,252		$ 88,058	$ 9,784				$ 97,842	$ 117,410
1609	Capital Contributions Paid	$ -					$ -	$ -	$ -					$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ -					$ -	$ -	$ -					$ -	$ -
1612	Land Rights (Formally known as Account 1906)	$ -					$ -	$ 189,356	$ -					$ -	$ -
1805	Land	$ 56,415					$ 56,415	$ 56,415	$ -					$ -	$ 56,415
1806	Land Rights	$ 375,398					$ 375,398		$ -					$ -	$ 375,398
1808	Buildings	$ 25,959,603	$ 577,035				$ 26,536,638	$ 25,035,547	$ 6,205,766	$ 731,555				$ 6,937,321	$ 19,599,317
1810	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 8,509,131	$ 275,973				$ 8,785,104	$ 7,954,869	$ 2,484,506	$ 307,707				$ 2,792,213	$ 5,992,891
1820	Distribution Station Equipment <50 kV	$ 42,182,458	$ 2,780,627				$ 44,963,085	$ 10,849,096	$ 4,348,777	$ 583,054		$ 150,503	$ 515,566	$ 5,597,900	$ 39,365,185
1825	Storage Battery Equipment	$ 13,722	$ -				$ 13,722	$ 13,722	$ 5,881	$ 653				$ 6,534	$ 7,187
1830	Poles, Towers & Fixtures	$ 28,543,225	$ 2,578,690				$ 31,121,915	$ 19,552,048	$ 3,833,115	$ 643,939			$ 24,283	$ 4,501,337	$ 26,620,578
1835	Overhead Conductors & Devices	$ 18,546,474	$ 811,945				$ 19,358,420	$ 13,939,351	$ 2,796,230	$ 373,298			$ 35,306	$ 3,204,834	$ 16,153,586
1840	Underground Conduit	$ 5,444,141	$ 1,091,561				$ 6,535,703	$ 4,067,747	$ 2,156,463	$ 281,047			$ -	$ 2,437,510	$ 4,098,193
1845	Underground Conductors & Devices	$ 16,327,524	$ 174,831				$ 16,502,355	$ 13,758,378	$ 4,975,637	$ 596,134			$ 25,578	$ 5,597,348	$ 10,905,007
1850	Line Transformers	$ 17,533,003	$ 1,302,668				$ 18,835,671	$ 13,978,734	$ 3,066,953	$ 447,171			$ 9,184	$ 3,523,308	$ 15,312,363
1855	Services (Overhead & Underground)	$ 8,679,331	$ 517,876				$ 9,197,207	$ 6,654,074	$ 1,569,587	$ 235,847				$ 1,805,434	$ 7,391,772
1860	Meters	$ 5,927,089	$ 206,980				$ 6,134,068	$ 4,984,479	$ 4,001,263	$ 510,377				$ 4,511,640	$ 1,622,429
1860	Meters (Smart Meters)	$ -					$ -	$ 4,984,479	$ -					$ -	$ -
1905	Land	$ -					$ -	$ -	$ -					$ -	$ -
1908	Buildings & Fixtures	$ -					$ -	$ -	$ -					$ -	$ -
1910	Leasehold Improvements	$ -					$ -	$ -	$ -					$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ -					$ -	$ -	$ -					$ -	$ -
1915	Office Furniture & Equipment (5 years)	$ -					$ -	$ -	$ -					$ -	$ -
1920	Computer Equipment - Hardware	$ -					$ -	$ -	$ -					$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -					$ -	$ -	$ -					$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ -					$ -	$ -	$ -					$ -	$ -
1930	Transportation Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1935	Stores Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1940	Tools, Shop & Garage Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1945	Measurement & Testing Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1950	Power Operated Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1955	Communications Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1955	Communication Equipment (Smart Meters)	$ -					$ -	$ -	$ -					$ -	$ -
1960	Miscellaneous Equipment	$ -					$ -	$ -	$ -					$ -	$ -
1970	Load Management Controls Customer Premises	$ -					$ -	$ -	$ -					$ -	$ -
1975	Load Management Controls Utility Premises	$ -					$ -	$ -	$ -					$ -	$ -
1980	System Supervisor Equipment	$ 5,322,336	$ 387,684				$ 5,710,020	$ 1,666,749	$ 1,598,426	$ 32,271			$ 174,458	$ 1,805,155	$ 3,904,865
1985	Miscellaneous Fixed Assets	$ -					$ -	$ -	$ -					$ -	$ -
1990	Other Tangible Property	$ -					$ -	$ -	$ -					$ -	$ -
1995	Contributions & Grants	-$ 11,161,739					-$ 11,161,739	$ -	-$ 2,954,578	-$ 328,286				-$ 3,282,864	-$ 7,878,875
2440	Deferred Revenue[5]	-$ 13,778,024	-$ 592,500				-$ 14,370,524	$ -	-$ 846,023	-$ 167,971			-$ 183,886	-$ 1,197,880	-$ 13,172,644
2005	Property Under Finance Lease[7]	0					$ -	$ -	0					$ -	$ -
	Sub-Total	**$ 161,835,900**	**$ 10,113,371**	**$ -**	**$ -**	**$ -**	**$ 171,949,271**	**$ 127,685,045**	**$ 33,923,922**	**$ 4,322,565**	**$ -**	**$ 150,503**	**$ 600,488**	**$ 38,997,478**	**$ 132,951,792**
	Less Socialized Renewable Energy Generation Investments **(input as negative)**						$ -							$ -	$ -
	Less Other Non Rate-Regulated Utility Assets (input as negative)						$ -							$ -	$ -
	Total PP&E	**$ 161,835,900**	**$ 10,113,371**	**$ -**	**$ -**	**$ -**	**$ 171,949,271**		**$ 33,923,922**	**$ 4,322,565**	**$ -**	**$ 150,503**	**$ 600,488**	**$ 38,997,478**	**$ 132,951,792**
	Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]														
	Total									**$ 5,073,556**					

	Transportation
	Stores Equipment
	Deferred Revenue

Less: *Fully Allocated Depreciation*

Transportation	
Stores Equipment	
Deferred Revenue	-$ 351,857
Net Depreciation	**$ 5,425,413**

APPENDIX B

Depreciation and

Amortization Expense

Board Appendix 2-C

Account	Description 2018	Book Values						
		Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions
		a	b	c = a-b	d	e	f = d- e	g
1706	Land Rights	$ 602,307		$ 602,307			$ -	$ -
1725	Poles and Fixtures	$ 1,604,339		$ 1,604,339			$ -	$ -
1730	Conductors	$ 63,894		$ 63,894			$ -	$ -
1735	UG Conduit	$ 870,020		$ 870,020			$ -	$ -
1740	UG Conductor	$ 215,252		$ 215,252			$ -	$ -
1611	Computer Software (Formally known as Account 1925)			$ -			$ -	$ -
1612	Land Rights (Formally known as Account 1906)			$ -			$ -	$ -
1805	Land	$ 89,160		$ 89,160			$ -	-$ 32,744
1806	Land Rights	$ 154,128		$ 154,128	$ 24,823		$ 24,823	$ 10,405
1808	Buildings	$ 24,624,967		$ 24,624,967	$ 402,125		$ 402,125	$ 8,455
1810	Leasehold Improvements	$ -		$ -			$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 5,491,722		$ 5,491,722	$ 2,170,884		$ 2,170,884	$ 292,263
1820	Distribution Station Equipment <50 kV	$ 7,812,618		$ 7,812,618	$ 2,698,024		$ 2,698,024	$ 338,454
1825	Storage Battery Equipment	$ 13,722		$ 13,722			$ -	$ -
1830	Poles, Towers & Fixtures	$ 10,446,415		$ 10,446,415	$ 7,361,688		$ 7,361,688	$ 1,743,944
1835	Overhead Conductors & Devices	$ 8,345,730		$ 8,345,730	$ 4,639,749		$ 4,639,749	$ 953,873
1840	Underground Conduit	$ 2,546,031		$ 2,546,031	$ 1,116,028		$ 1,116,028	$ 405,688
1845	Underground Conductors & Devices	$ 11,437,100		$ 11,437,100	$ 2,010,179		$ 2,010,179	$ 311,100
1850	Line Transformers	$ 9,204,093		$ 9,204,093	$ 4,052,543		$ 4,052,543	$ 722,098
1855	Services (Overhead & Underground)	$ 4,460,589		$ 4,460,589	$ 1,616,042		$ 1,616,042	$ 577,442
1860	Meters			$ -			$ -	$ -
1860	Meters (Smart Meters)	$ 4,468,973		$ 4,468,973	$ 369,593		$ 369,593	$ 145,913
1905	Land			$ -			$ -	$ -
1908	Buildings & Fixtures			$ -			$ -	$ -
1910	Leasehold Improvements			$ -			$ -	$ -
1915	Office Furniture & Equipment (10 years)			$ -			$ -	$ -
1915	Office Furniture & Equipment (5 years)			$ -			$ -	$ -
1920	Computer Equipment - Hardware	$ 1,361	$ 1,361	$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -			$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -			$ -	$ -
1930	Transportation Equipment			$ -			$ -	$ -
1935	Stores Equipment			$ -			$ -	$ -
1940	Tools, Shop & Garage Equipment			$ -			$ -	$ -
1945	Measurement & Testing Equipment			$ -			$ -	$ -
1950	Power Operated Equipment			$ -			$ -	$ -
1955	Communications Equipment			$ -			$ -	$ -
1955	Communication Equipment (Smart Meters)			$ -			$ -	$ -
1960	Miscellaneous Equipment			$ -			$ -	$ -
1970	Load Management Controls Customer Premises			$ -			$ -	$ -
1975	Load Management Controls Utility Premises			$ -			$ -	$ -
1980	System Supervisor Equipment	$ 1,381,611		$ 1,381,611	$ 219,062		$ 219,062	$ 66,076
1985	Miscellaneous Fixed Assets			$ -			$ -	$ -
1990	Other Tangible Property			$ -			$ -	$ -
1995	Contributions & Grants	-$ 11,161,740		-$ 11,161,740	$ 1		$ 1	$ -
2440	Deferred Revenue				-$ 3,087,531		-$ 3,087,531	-$ 431,033
2005	Property Under Finance Lease			$ -			$ -	$ -
	Total	**$ 82,672,294**	**$ 1,361**	**$ 82,670,933**	**$ 23,593,210**	**$ -**	**$ 23,593,210**	**$ 5,111,934**

	2018	Service Lives				Depreciation Expense					
Account	Description	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1706	Land Rights		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1725	Poles and Fixtures	41.00	2.44%	45.00	2.22%	$ 39,130	$ -	$ -	$ 39,130	$ 39,130	-$ 0
1730	Conductors	32.00	3.13%	45.00	2.22%	$ 1,997	$ -	$ -	$ 1,997	$ 1,997	-$ 0
1735	UG Conduit	35.00	2.86%	40.00	2.50%	$ 24,858	$ -	$ -	$ 24,858	$ 24,858	-$ 0
1740	UG Conductor	22.00	4.55%	25.00	4.00%	$ 9,784	$ -	$ -	$ 9,784	$ 9,784	$ 0
1611	Computer Software (Formally known as Account 1925)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1806	Land Rights	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	36.60	2.73%	39.60	2.53%	$ 672,848	$ 10,155	$ 107	$ 683,110	$ 683,038	-$ 72
1810	Leasehold Improvements	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	24.00	4.17%	40.00	2.50%	$ 228,822	$ 54,272	$ 3,653	$ 286,747	$ 286,747	$ 0
1820	Distribution Station Equipment <50 kV	22.00	4.55%	40.00	2.50%	$ 355,119	$ 67,451	$ 4,231	$ 426,800	$ 426,800	-$ 0
1825	Storage Battery Equipment	21.00	4.76%	30.00	3.33%	$ 653	$ -	$ -	$ 653	$ 653	-$ 0
1830	Poles, Towers & Fixtures	44.00	2.27%	45.00	2.22%	$ 237,419	$ 163,593	$ 19,377	$ 420,389	$ 420,389	$ 0
1835	Overhead Conductors & Devices	36.00	2.78%	60.00	1.67%	$ 231,826	$ 77,329	$ 7,949	$ 317,104	$ 317,104	$ 0
1840	Underground Conduit	12.00	8.33%	50.00	2.00%	$ 212,169	$ 22,321	$ 4,057	$ 238,547	$ 238,547	-$ 0
1845	Underground Conductors & Devices	23.00	4.35%	40.00	2.50%	$ 497,265	$ 50,254	$ 3,889	$ 551,408	$ 551,408	$ 0
1850	Line Transformers	39.00	2.56%	40.00	2.50%	$ 236,002	$ 101,314	$ 9,026	$ 346,342	$ 346,378	$ 36
1855	Services (Overhead & Underground)	36.00	2.78%	40.00	2.50%	$ 123,905	$ 40,401	$ 7,218	$ 171,524	$ 166,936	-$ 4,588
1860	Meters		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters (Smart Meters)	11.00	9.09%	15.00	6.67%	$ 406,270	$ 24,640	$ 4,864	$ 435,774	$ 435,774	-$ 0
1905	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1935	Stores Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1945	Measurement & Testing Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	6.00	16.67%	20.00	5.00%	$ 230,269	$ 10,953	$ 1,652	$ 242,873	$ 242,873	-$ 0
1985	Miscellaneous Fixed Assets		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	34.00	2.94%	40.00	2.50%	-$ 328,286	$ 0	$ -	-$ 328,286	-$ 328,286	$ 0
2440	Deferred Revenue		0.00%	40.00	2.50%	$ -	-$ 77,188	-$ 5,388	-$ 82,576	-$ 82,576	$ 0
2005	Property Under Finance Lease		0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
	Total					$ 3,180,050	$ 545,494	$ 60,634	$ 3,786,178	$ 3,781,555	-$ 4,623

	2019	Book Values						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions
		a	b	c = a-b	d	e	f = d- e	g
1706	Land Rights	$ 602,307		$ 602,307	$ -		$ -	$ -
1725	Poles and Fixtures	$ 1,604,339		$ 1,604,339	$ -		$ -	$ -
1730	Conductors	$ 63,894		$ 63,894	$ -		$ -	$ -
1735	UG Conduit	$ 870,020		$ 870,020	$ -		$ -	$ -
1740	UG Conductor	$ 215,252		$ 215,252	$ -		$ -	$ -
1611	Computer Software (Formally known as Account 1925)			$ -	$ -		$ -	$ -
1612	Land Rights (Formally known as Account 1906)			$ -	$ -		$ -	$ -
1805	Land	$ 89,160		$ 89,160	-$ 32,744		-$ 32,744	$ -
1806	Land Rights	$ 154,128		$ 154,128	$ 35,228		$ 35,228	$ 14,311
1808	Buildings	$ 24,624,967		$ 24,624,967	$ 410,580		$ 410,580	$ 177,803
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 5,491,722		$ 5,491,722	$ 2,463,147		$ 2,463,147	$ 233,949
1820	Distribution Station Equipment <50 kV	$ 7,812,618		$ 7,812,618	$ 3,036,478		$ 3,036,478	$ 226,273
1825	Storage Battery Equipment	$ 13,722		$ 13,722	$ -		$ -	$ -
1830	Poles, Towers & Fixtures	$ 10,446,415		$ 10,446,415	$ 9,105,633		$ 9,105,633	$ 2,058,945
1835	Overhead Conductors & Devices	$ 8,345,730		$ 8,345,730	$ 5,593,621		$ 5,593,621	$ 646,542
1840	Underground Conduit	$ 2,546,031		$ 2,546,031	$ 1,521,716		$ 1,521,716	$ 494,913
1845	Underground Conductors & Devices	$ 11,437,100		$ 11,437,100	$ 2,321,278		$ 2,321,278	$ 314,478
1850	Line Transformers	$ 9,204,093		$ 9,204,093	$ 4,774,641		$ 4,774,641	$ 898,402
1855	Services (Overhead & Underground)	$ 4,460,589		$ 4,460,589	$ 2,193,485		$ 2,193,485	$ 536,808
1860	Meters			$ -	$ -		$ -	$ -
1860	Meters (Smart Meters)	$ 4,468,973		$ 4,468,973	$ 515,506		$ 515,506	$ 76,616
1905	Land			$ -	$ -		$ -	$ -
1908	Buildings & Fixtures			$ -	$ -		$ -	$ -
1910	Leasehold Improvements			$ -	$ -		$ -	$ -
1915	Office Furniture & Equipment (10 years)			$ -	$ -		$ -	$ -
1915	Office Furniture & Equipment (5 years)			$ -	$ -		$ -	$ -
1920	Computer Equipment - Hardware	$ 1,361	$ 1,361	$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -	$ -		$ -	$ -
1930	Transportation Equipment			$ -	$ -		$ -	$ -
1935	Stores Equipment			$ -	$ -		$ -	$ -
1940	Tools, Shop & Garage Equipment			$ -	$ -		$ -	$ -
1945	Measurement & Testing Equipment			$ -	$ -		$ -	$ -
1950	Power Operated Equipment			$ -	$ -		$ -	$ -
1955	Communications Equipment			$ -	$ -		$ -	$ -
1955	Communication Equipment (Smart Meters)			$ -	$ -		$ -	$ -
1960	Miscellaneous Equipment			$ -	$ -		$ -	$ -
1970	Load Management Controls Customer Premises			$ -	$ -		$ -	$ -
1975	Load Management Controls Utility Premises			$ -	$ -		$ -	$ -
1980	System Supervisor Equipment	$ 1,381,611		$ 1,381,611	$ 285,138		$ 285,138	$ 156,497
1985	Miscellaneous Fixed Assets			$ -	$ -		$ -	$ -
1990	Other Tangible Property			$ -	$ -		$ -	$ -
1995	Contributions & Grants	-$ 11,161,740		-$ 11,161,740	$ 1		$ 1	$ -
2440	Deferred Revenue				-$ 3,518,564		-$ 3,518,564	-$ 1,111,843
2005	Property Under Finance Lease			$ -	$ -		$ -	$ -
	Total	**$ 82,672,294**	**$ 1,361**	**$ 82,670,933**	**$ 28,705,145**	**$ -**	**$ 28,705,145**	**$ 4,723,694**

	2019	Service Lives				Depreciation Expense					
Account	Description	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1706	Land Rights		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1725	Poles and Fixtures	41.00	2.44%	45.00	2.22%	$ 39,130	$ -	$ -	$ 39,130	$ 39,130	-$ 0
1730	Conductors	32.00	3.13%	45.00	2.22%	$ 1,997	$ -	$ -	$ 1,997	$ 1,997	-$ 0
1735	UG Conduit	35.00	2.86%	40.00	2.50%	$ 24,858	$ -	$ -	$ 24,858	$ 24,858	-$ 0
1740	UG Conductor	22.00	4.55%	25.00	4.00%	$ 9,784	$ -	$ -	$ 9,784	$ 9,784	$ 0
1611	Computer Software (Formally known as Account 1925)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1806	Land Rights	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	36.60	2.73%	39.44	2.54%	$ 672,795	$ 10,411	$ 3,556	$ 686,762	$ 686,763	$ 1
1810	Leasehold Improvements	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	24.00	4.17%	40.00	2.50%	$ 228,822	$ 61,579	$ 2,924	$ 293,325	$ 293,325	$ 0
1820	Distribution Station Equipment <50 kV	22.00	4.55%	40.00	2.50%	$ 355,119	$ 75,912	$ 2,828	$ 433,859	$ 433,859	-$ 0
1825	Storage Battery Equipment	21.00	4.76%	30.00	3.33%	$ 653	$ -	$ -	$ 653	$ 653	-$ 0
1830	Poles, Towers & Fixtures	44.00	2.27%	45.00	2.22%	$ 237,419	$ 202,347	$ 22,877	$ 462,643	$ 462,643	-$ 0
1835	Overhead Conductors & Devices	36.00	2.78%	60.00	1.67%	$ 231,826	$ 93,227	$ 5,388	$ 330,441	$ 330,441	$ 0
1840	Underground Conduit	12.00	8.33%	50.00	2.00%	$ 212,169	$ 30,434	$ 4,949	$ 247,553	$ 247,553	-$ 0
1845	Underground Conductors & Devices	23.00	4.35%	40.00	2.50%	$ 497,265	$ 58,032	$ 3,931	$ 559,228	$ 559,228	$ 0
1850	Line Transformers	39.00	2.56%	40.00	2.50%	$ 236,002	$ 119,366	$ 11,230	$ 366,598	$ 367,055	$ 457
1855	Services (Overhead & Underground)	36.00	2.78%	40.00	2.50%	$ 123,905	$ 54,837	$ 6,710	$ 185,452	$ 190,040	$ 4,588
1860	Meters		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1860	Meters (Smart Meters)	11.00	9.09%	15.00	6.67%	$ 406,270	$ 34,367	$ 2,554	$ 443,191	$ 443,191	-$ 0
1905	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1935	Stores Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1945	Measurement & Testing Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	6.00	16.67%	20.00	5.00%	$ 230,269	$ 14,257	$ 3,912	$ 248,438	$ 248,438	-$ 0
1985	Miscellaneous Fixed Assets		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	34.00	2.94%	40.00	2.50%	-$ 328,286	$ 0	$ -	-$ 328,286	-$ 328,286	$ 0
2440	Deferred Revenue		0.00%	40.00	2.50%	$ -	-$ 87,964	-$ 13,898	-$ 101,862	-$ 101,862	$ 0
2005	Property Under Finance Lease		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
	Total					$ 3,179,997	$ 666,805	$ 56,962	$ 3,903,764	$ 3,908,810	$ 5,045

	2020	Book Values						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions
		a	b	c = a-b	d	e	f = d- e	g
1706	Land Rights	$ 602,307		$ 602,307	$ -		$ -	$ -
1725	Poles and Fixtures	$ 1,604,339		$ 1,604,339	$ -		$ -	$ -
1730	Conductors	$ 63,894		$ 63,894	$ -		$ -	$ -
1735	UG Conduit	$ 870,020		$ 870,020	$ -		$ -	$ -
1740	UG Conductor	$ 215,252		$ 215,252	$ -		$ -	$ -
1611	Computer Software (Formally known as Account 1925)			$ -	$ -		$ -	$ -
1612	Land Rights (Formally known as Account 1906)			$ -	$ -		$ -	$ -
1805	Land	$ 89,160		$ 89,160	-$ 32,744		-$ 32,744	$ -
1806	Land Rights	$ 154,128		$ 154,128	$ 49,539		$ 49,539	$ 14,268
1808	Buildings	$ 24,624,967		$ 24,624,967	$ 588,384		$ 588,384	$ 125,719
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 5,491,722		$ 5,491,722	$ 2,697,096		$ 2,697,096	$ 184,850
1820	Distribution Station Equipment <50 kV	$ 7,812,618		$ 7,812,618	$ 3,262,751		$ 3,262,751	$ 531,294
1825	Storage Battery Equipment	$ 13,722		$ 13,722	$ -		$ -	$ -
1830	Poles, Towers & Fixtures	$ 10,446,415		$ 10,446,415	$ 11,164,577		$ 11,164,577	$ 1,797,499
1835	Overhead Conductors & Devices	$ 8,345,730		$ 8,345,730	$ 6,240,163		$ 6,240,163	$ 783,153
1840	Underground Conduit	$ 2,546,031		$ 2,546,031	$ 2,016,629		$ 2,016,629	$ 62,255
1845	Underground Conductors & Devices	$ 11,437,100		$ 11,437,100	$ 2,635,756		$ 2,635,756	$ 554,440
1850	Line Transformers	$ 9,204,093		$ 9,204,093	$ 5,673,043		$ 5,673,043	$ 953,608
1855	Services (Overhead & Underground)	$ 4,460,589		$ 4,460,589	$ 2,730,292		$ 2,730,292	$ 392,402
1860	Meters			$ -	$ -		$ -	
1860	Meters (Smart Meters)	$ 4,468,973		$ 4,468,973	$ 592,122		$ 592,122	$ 476,303
1905	Land			$ -	$ -		$ -	$ -
1908	Buildings & Fixtures			$ -	$ -		$ -	$ -
1910	Leasehold Improvements			$ -	$ -		$ -	$ -
1915	Office Furniture & Equipment (10 years)			$ -	$ -		$ -	$ -
1915	Office Furniture & Equipment (5 years)			$ -	$ -		$ -	$ -
1920	Computer Equipment - Hardware	$ 1,361	$ 1,361	$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -	$ -		$ -	$ -
1930	Transportation Equipment			$ -	$ -		$ -	$ -
1935	Stores Equipment			$ -	$ -		$ -	$ -
1940	Tools, Shop & Garage Equipment			$ -	$ -		$ -	$ -
1945	Measurement & Testing Equipment			$ -	$ -		$ -	$ -
1950	Power Operated Equipment			$ -	$ -		$ -	$ -
1955	Communications Equipment			$ -	$ -		$ -	$ -
1955	Communication Equipment (Smart Meters)			$ -	$ -		$ -	$ -
1960	Miscellaneous Equipment			$ -	$ -		$ -	$ -
1970	Load Management Controls Customer Premises			$ -	$ -		$ -	$ -
1975	Load Management Controls Utility Premises			$ -	$ -		$ -	$ -
1980	System Supervisor Equipment	$ 1,381,611	$ 1,381,611	$ -	$ 441,635		$ 441,635	$ 9,935
1985	Miscellaneous Fixed Assets			$ -	$ -		$ -	$ -
1990	Other Tangible Property			$ -	$ -		$ -	$ -
1995	Contributions & Grants	-$ 11,161,740		-$ 11,161,740	$ 1		$ 1	$ -
2440	Deferred Revenue				-$ 4,630,407		-$ 4,630,407	-$ 658,166
2005	Property Under Finance Lease			$ -	$ -		$ -	$ -
	Total	**$ 82,672,294**	**$ 1,382,972**	**$ 81,289,322**	**$ 33,428,839**	**$ -**	**$ 33,428,839**	**$ 5,227,561**

	2020	Service Lives				Depreciation Expense					
Account	Description	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1706	Land Rights		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1725	Poles and Fixtures	41.00	2.44%	45.00	2.22%	$ 39,130	$ -	$ -	$ 39,130	$ 39,130	-$ 0
1730	Conductors	32.00	3.13%	45.00	2.22%	$ 1,997	$ -	$ -	$ 1,997	$ 1,997	-$ 0
1735	UG Conduit	35.00	2.86%	40.00	2.50%	$ 24,858	$ -	$ -	$ 24,858	$ 24,858	-$ 0
1740	UG Conductor	22.00	4.55%	25.00	4.00%	$ 9,784	$ -	$ -	$ 9,784	$ 9,784	$ 0
1611	Computer Software (Formally known as Account 1925)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1806	Land Rights	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	36.60	2.73%	33.58	2.98%	$ 672,795	$ 17,523	$ 2,514	$ 692,833	$ 692,833	$ 1
1810	Leasehold Improvements	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	24.00	4.17%	40.00	2.50%	$ 228,822	$ 67,427	$ 2,311	$ 298,560	$ 298,560	$ 0
1820	Distribution Station Equipment <50 kV	22.00	4.55%	40.00	2.50%	$ 355,119	$ 81,569	$ 6,641	$ 443,329	$ 443,329	-$ 0
1825	Storage Battery Equipment	21.00	4.76%	30.00	3.33%	$ 653	$ -	$ -	$ 653	$ 653	-$ 0
1830	Poles, Towers & Fixtures	44.00	2.27%	45.00	2.22%	$ 237,419	$ 248,102	$ 19,972	$ 505,492	$ 505,492	$ 0
1835	Overhead Conductors & Devices	36.00	2.78%	60.00	1.67%	$ 231,826	$ 104,003	$ 6,526	$ 342,355	$ 342,355	$ 0
1840	Underground Conduit	12.00	8.33%	50.00	2.00%	$ 212,169	$ 40,333	$ 623	$ 253,124	$ 253,124	-$ 0
1845	Underground Conductors & Devices	23.00	4.35%	40.00	2.50%	$ 497,265	$ 65,894	$ 6,931	$ 570,090	$ 570,090	$ 0
1850	Line Transformers	39.00	2.56%	40.00	2.50%	$ 236,002	$ 141,826	$ 11,920	$ 389,749	$ 388,011	-$ 1,738
1855	Services (Overhead & Underground)	36.00	2.78%	40.00	2.50%	$ 123,905	$ 68,257	$ 4,905	$ 197,068	$ 197,068	$ 0
1860	Meters		0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	11.00	9.09%	15.00	6.67%	$ 406,270	$ 39,475	$ 15,877	$ 461,622	$ 461,622	-$ 0
1905	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1935	Stores Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1945	Measurement & Testing Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	6.00	16.67%	20.00	5.00%	$ -	$ 22,082	$ 248	$ 22,330	$ 252,599	$ 230,268
1985	Miscellaneous Fixed Assets		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	34.00	2.94%	40.00	2.50%	-$ 328,286	$ 0	$ -	-$ 328,286	-$ 328,286	$ 0
2440	Deferred Revenue		0.00%	40.00	2.50%	$ -	-$ 115,760	-$ 8,227	-$ 123,987	-$ 123,987	$ 0
2005	Property Under Finance Lease		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
	Total					**$ 2,949,728**	**$ 780,730**	**$ 70,241**	**$ 3,800,699**	**$ 4,029,231**	**$ 228,531**

	2021	Book Values						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions
		a	b	c = a-b	d	e	f = d- e	g
1706	Land Rights	$ 602,307		$ 602,307	$ -		$ -	$ -
1725	Poles and Fixtures	$ 1,604,339		$ 1,604,339	$ -		$ -	$ -
1730	Conductors	$ 63,894		$ 63,894	$ -		$ -	$ -
1735	UG Conduit	$ 870,020		$ 870,020	$ -		$ -	$ -
1740	UG Conductor	$ 215,252		$ 215,252	$ -		$ -	$ -
1611	Computer Software (Formally known as Account 1925)			$ -	$ -		$ -	$ -
1612	Land Rights (Formally known as Account 1906)			$ -	$ -		$ -	$ -
1805	Land	$ 89,160		$ 89,160	-$ 32,744		-$ 32,744	$ -
1806	Land Rights	$ 154,128		$ 154,128	$ 63,807		$ 63,807	$ 157,463
1808	Buildings	$ 24,624,967		$ 24,624,967	$ 714,103		$ 714,103	$ 584,705
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 5,491,722		$ 5,491,722	$ 2,881,946		$ 2,881,946	$ 70,828
1820	Distribution Station Equipment <50 kV	$ 7,812,618		$ 7,812,618	$ 3,794,044		$ 3,794,044	$ 575,333
1825	Storage Battery Equipment	$ 13,722		$ 13,722	$ -		$ -	$ -
1830	Poles, Towers & Fixtures	$ 10,446,415		$ 10,446,415	$ 12,962,077		$ 12,962,077	$ 1,574,663
1835	Overhead Conductors & Devices	$ 8,345,730		$ 8,345,730	$ 7,023,316		$ 7,023,316	$ 507,099
1840	Underground Conduit	$ 2,546,031		$ 2,546,031	$ 2,078,885		$ 2,078,885	$ 183,281
1845	Underground Conductors & Devices	$ 11,437,100		$ 11,437,100	$ 3,190,197		$ 3,190,197	$ 563,813
1850	Line Transformers	$ 9,204,093		$ 9,204,093	$ 6,626,651		$ 6,626,651	$ 772,929
1855	Services (Overhead & Underground)	$ 4,460,589		$ 4,460,589	$ 3,122,694		$ 3,122,694	$ 592,995
1860	Meters			$ -	$ -		$ -	$ 216,522
1860	Meters (Smart Meters)	$ 4,468,973		$ 4,468,973	$ 1,068,425		$ 1,068,425	$ 216,522
1905	Land			$ -	$ -		$ -	$ -
1908	Buildings & Fixtures			$ -	$ -		$ -	$ -
1910	Leasehold Improvements			$ -	$ -		$ -	$ -
1915	Office Furniture & Equipment (10 years)			$ -	$ -		$ -	$ -
1915	Office Furniture & Equipment (5 years)			$ -	$ -		$ -	$ -
1920	Computer Equipment - Hardware	$ 1,361	$ 1,361	$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -	$ -		$ -	$ -
1930	Transportation Equipment			$ -	$ -		$ -	$ -
1935	Stores Equipment			$ -	$ -		$ -	$ -
1940	Tools, Shop & Garage Equipment			$ -	$ -		$ -	$ -
1945	Measurement & Testing Equipment			$ -	$ -		$ -	$ -
1950	Power Operated Equipment			$ -	$ -		$ -	$ -
1955	Communications Equipment			$ -	$ -		$ -	$ -
1955	Communication Equipment (Smart Meters)			$ -	$ -		$ -	$ -
1960	Miscellaneous Equipment			$ -	$ -		$ -	$ -
1970	Load Management Controls Customer Premises			$ -	$ -		$ -	$ -
1975	Load Management Controls Utility Premises			$ -	$ -		$ -	$ -
1980	System Supervisor Equipment	$ 1,381,611	$ 1,381,611	$ -	$ 451,571		$ 451,571	$ -
1985	Miscellaneous Fixed Assets			$ -	$ -		$ -	$ -
1990	Other Tangible Property			$ -	$ -		$ -	$ -
1995	Contributions & Grants	-$ 11,161,740		-$ 11,161,740	$ 1		$ 1	$ -
2440	Deferred Revenue				-$ 5,288,573		-$ 5,288,573	-$ 641,214
2005	Property Under Finance Lease			$ -	$ -		$ -	$ -
	Total	**$ 82,672,294**	**$ 1,382,972**	**$ 81,289,322**	**$ 38,656,400**	**$ -**	**$ 38,656,400**	**$ 5,374,938**

Account	2021 Description	Service Lives Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1706	Land Rights		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1725	Poles and Fixtures	41.00	2.44%	45.00	2.22%	$ 39,130	$ -	$ -	$ 39,130	$ 39,130	-$ 0
1730	Conductors	32.00	3.13%	45.00	2.22%	$ 1,997	$ -	$ -	$ 1,997	$ 1,997	-$ 0
1735	UG Conduit	35.00	2.86%	40.00	2.50%	$ 24,858	$ -	$ -	$ 24,858	$ 24,858	-$ 0
1740	UG Conductor	22.00	4.55%	25.00	4.00%	$ 9,784	$ -	$ -	$ 9,784	$ 9,784	$ 0
1611	Computer Software (Formally known as Account 1925)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1806	Land Rights	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	36.63	2.73%	31.66	3.16%	$ 672,175	$ 22,552	$ 11,694	$ 706,421	$ 706,421	$ 0
1810	Leasehold Improvements	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	24.00	4.17%	40.00	2.50%	$ 228,822	$ 72,049	$ 885	$ 301,756	$ 301,756	-$ 0
1820	Distribution Station Equipment <50 kV	22.00	4.55%	40.00	2.50%	$ 355,119	$ 94,851	$ 7,192	$ 457,162	$ 457,162	-$ 0
1825	Storage Battery Equipment	21.00	4.76%	30.00	3.33%	$ 653	$ -	$ -	$ 653	$ 653	-$ 0
1830	Poles, Towers & Fixtures	44.00	2.27%	45.00	2.22%	$ 237,419	$ 288,046	$ 17,496	$ 542,961	$ 542,961	-$ 0
1835	Overhead Conductors & Devices	36.00	2.78%	60.00	1.67%	$ 231,826	$ 117,055	$ 4,226	$ 353,107	$ 353,107	-$ 0
1840	Underground Conduit	12.00	8.33%	50.00	2.00%	$ 212,169	$ 41,578	$ 1,833	$ 255,580	$ 255,580	$ 0
1845	Underground Conductors & Devices	23.00	4.35%	40.00	2.50%	$ 497,265	$ 79,755	$ 7,048	$ 584,068	$ 584,068	$ 0
1850	Line Transformers	39.00	2.56%	40.00	2.50%	$ 236,002	$ 165,666	$ 9,662	$ 411,330	$ 406,873	-$ 4,457
1855	Services (Overhead & Underground)	36.00	2.78%	40.00	2.50%	$ 123,905	$ 78,067	$ 7,412	$ 209,385	$ 209,385	-$ 0
1860	Meters		0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	11.00	9.09%	15.00	6.67%	$ 406,270	$ 71,228	$ 7,217	$ 484,716	$ 484,716	-$ 0
1905	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1935	Stores Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1945	Measurement & Testing Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	6.00	16.67%	20.00	5.00%	$ -	$ 22,579	$ -	$ 22,579	-$ 207,938	-$ 230,517
1985	Miscellaneous Fixed Assets		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	34.00	2.94%	40.00	2.50%	-$ 328,286	$ 0	$ -	-$ 328,286	-$ 328,286	$ 0
2440	Deferred Revenue		0.00%	40.00	2.50%	$ -	-$ 132,214	-$ 8,015	-$ 140,229	-$ 140,229	$ 0
2005	Property Under Finance Lease		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
	Total					$ 2,949,109	$ 921,212	$ 66,650	$ 3,936,970	$ 3,701,996	-$ 234,974

	2022	Book Values						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions
		a	b	c = a-b	d	e	f = d- e	g
1706	Land Rights	$ 602,307		$ 602,307	$ -		$ -	$ -
1725	Poles and Fixtures	$ 1,604,339		$ 1,604,339	$ -		$ -	$ -
1730	Conductors	$ 63,894		$ 63,894	$ -		$ -	$ -
1735	UG Conduit	$ 870,020		$ 870,020	$ -		$ -	$ -
1740	UG Conductor	$ 215,252		$ 215,252	$ -		$ -	$ -
1611	Computer Software (Formally known as Account 1925)			$ -	$ -		$ -	$ -
1612	Land Rights (Formally known as Account 1906)			$ -	$ -		$ -	$ -
1805	Land	$ 89,160		$ 89,160	-$ 32,744		-$ 32,744	$ -
1806	Land Rights	$ 154,128		$ 154,128	$ 221,270		$ 221,270	$ -
1808	Buildings	$ 24,624,967	$ 621	$ 24,624,346	$ 1,298,808		$ 1,298,808	$ 35,828
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 5,491,722		$ 5,491,722	$ 2,952,773		$ 2,952,773	$ 64,636
1820	Distribution Station Equipment <50 kV	$ 7,812,618		$ 7,812,618	$ 4,369,377		$ 4,369,377	$ 30,000,462
1825	Storage Battery Equipment	$ 13,722		$ 13,722	$ -		$ -	$ -
1830	Poles, Towers & Fixtures	$ 10,446,415		$ 10,446,415	$ 14,536,740		$ 14,536,740	$ 3,560,071
1835	Overhead Conductors & Devices	$ 8,345,730		$ 8,345,730	$ 7,530,414		$ 7,530,414	$ 2,670,330
1840	Underground Conduit	$ 2,546,031		$ 2,546,031	$ 2,262,166		$ 2,262,166	$ 635,945
1845	Underground Conductors & Devices	$ 11,437,100		$ 11,437,100	$ 3,754,009		$ 3,754,009	$ 1,136,415
1850	Line Transformers	$ 9,204,093		$ 9,204,093	$ 7,399,580		$ 7,399,580	$ 929,330
1855	Services (Overhead & Underground)	$ 4,460,589		$ 4,460,589	$ 3,715,689		$ 3,715,689	$ 503,053
1860	Meters			$ -	$ 216,522		$ 216,522	
1860	Meters (Smart Meters)	$ 4,468,973		$ 4,468,973	$ 1,284,947		$ 1,284,947	$ 173,168
1905	Land			$ -	$ -		$ -	$ -
1908	Buildings & Fixtures			$ -	$ -		$ -	$ -
1910	Leasehold Improvements			$ -	$ -		$ -	$ -
1915	Office Furniture & Equipment (10 years)			$ -	$ -		$ -	$ -
1915	Office Furniture & Equipment (5 years)			$ -	$ -		$ -	$ -
1920	Computer Equipment - Hardware	$ 1,361	$ 1,361	$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -	$ -		$ -	$ -
1930	Transportation Equipment			$ -	$ -		$ -	$ -
1935	Stores Equipment			$ -	$ -		$ -	$ -
1940	Tools, Shop & Garage Equipment			$ -	$ -		$ -	$ -
1945	Measurement & Testing Equipment			$ -	$ -		$ -	$ -
1950	Power Operated Equipment			$ -	$ -		$ -	$ -
1955	Communications Equipment			$ -	$ -		$ -	$ -
1955	Communication Equipment (Smart Meters)			$ -	$ -		$ -	$ -
1960	Miscellaneous Equipment			$ -	$ -		$ -	$ -
1970	Load Management Controls Customer Premises			$ -	$ -		$ -	$ -
1975	Load Management Controls Utility Premises			$ -	$ -		$ -	$ -
1980	System Supervisor Equipment	$ 1,381,611	$ 1,381,611	$ -	$ 451,571		$ 451,571	$ 3,489,154
1985	Miscellaneous Fixed Assets			$ -	$ -		$ -	$ -
1990	Other Tangible Property			$ -	$ -		$ -	$ -
1995	Contributions & Grants	-$ 11,161,740		-$ 11,161,740	$ 1		$ 1	$ -
2440	Deferred Revenue			$ -	-$ 5,929,786		-$ 5,929,786	-$ 7,848,238
2005	Property Under Finance Lease			$ -	$ -		$ -	$ -
	Total	**$ 82,672,294**	**$ 1,383,593**	**$ 81,288,701**	**$ 44,031,338**	**$ -**	**$ 44,031,338**	**$ 35,350,153**

	2022	Service Lives				Depreciation Expense					
Account	Description	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1706	Land Rights		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1725	Poles and Fixtures	41.00	2.44%	45.00	2.22%	$ 39,130	$ -	$ -	$ 39,130	$ 39,130	-$ 0
1730	Conductors	32.00	3.13%	45.00	2.22%	$ 1,997	$ -	$ -	$ 1,997	$ 1,997	-$ 0
1735	UG Conduit	35.00	2.86%	40.00	2.50%	$ 24,858	$ -	$ -	$ 24,858	$ 24,858	-$ 0
1740	UG Conductor	22.00	4.55%	25.00	4.00%	$ 9,784	$ -	$ -	$ 9,784	$ 9,784	$ 0
1611	Computer Software (Formally known as Account 1925)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1806	Land Rights	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	36.61	2.73%	28.27	3.54%	$ 672,641	$ 45,940	$ 717	$ 719,297	$ 719,297	$ 0
1810	Leasehold Improvements	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	24.00	4.17%	40.00	2.50%	$ 228,822	$ 73,819	$ 808	$ 303,449	$ 303,449	$ 0
1820	Distribution Station Equipment <50 kV	22.00	4.55%	40.00	2.50%	$ 355,119	$ 109,234	$ 375,006	$ 839,359	$ 989,862	$ 150,503
1825	Storage Battery Equipment	21.00	4.76%	30.00	3.33%	$ 653	$ -	$ -	$ 653	$ 653	-$ 0
1830	Poles, Towers & Fixtures	44.00	2.27%	45.00	2.22%	$ 237,419	$ 323,039	$ 39,556	$ 600,014	$ 600,014	-$ 0
1835	Overhead Conductors & Devices	36.00	2.78%	60.00	1.67%	$ 231,826	$ 125,507	$ 22,253	$ 379,585	$ 379,585	$ 0
1840	Underground Conduit	12.00	8.33%	50.00	2.00%	$ 212,169	$ 45,243	$ 6,359	$ 263,772	$ 263,772	$ 0
1845	Underground Conductors & Devices	23.00	4.35%	40.00	2.50%	$ 497,265	$ 93,850	$ 14,205	$ 605,321	$ 605,321	$ 0
1850	Line Transformers	39.00	2.56%	40.00	2.50%	$ 236,002	$ 184,990	$ 11,617	$ 432,609	$ 428,455	-$ 4,153
1855	Services (Overhead & Underground)	36.00	2.78%	40.00	2.50%	$ 123,905	$ 92,892	$ 6,288	$ 223,086	$ 223,086	$ 0
1860	Meters		0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	11.00	9.09%	15.00	6.67%	$ 406,270	$ 85,663	$ 5,772	$ 497,706	$ 497,706	-$ 0
1905	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1935	Stores Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1945	Measurement & Testing Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	6.00	16.67%	20.00	5.00%	$ -	$ 22,579	$ 87,229	$ 109,807	$ 109,807	$ 0
1985	Miscellaneous Fixed Assets		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	34.00	2.94%	40.00	2.50%	-$ 328,286	$ 0	$ -	-$ 328,286	-$ 328,286	$ 0
2440	Deferred Revenue		0.00%	40.00	2.50%	$ -	-$ 148,245	-$ 98,103	-$ 246,348	-$ 246,348	-$ 0
2005	Property Under Finance Lease		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
	Total					$ 2,949,574	$ 1,054,512	$ 471,707	$ 4,475,793	$ 4,622,142	$ 146,349

	2023	Book Values						
Account	Description	Opening Net Book Value of Existing Assets as at Date of Policy Change (Jan. 1) [1]	Less Fully Depreciated [7]	Net Amount of Existing Assets Before Policy Change to be Depreciated	Opening Gross Book Value of Assets Acquired After Policy Change [2]	Less Fully Depreciated [8]	Net Amount of Assets Acquired After Policy Change to be Depreciated	Current Year Additions
		a	b	c = a-b	d	e	f = d- e	g
1706	Land Rights	$ 602,307		$ 602,307	$ -		$ -	$ -
1725	Poles and Fixtures	$ 1,604,339		$ 1,604,339	$ -		$ -	$ -
1730	Conductors	$ 63,894		$ 63,894	$ -		$ -	$ -
1735	UG Conduit	$ 870,020		$ 870,020	$ -		$ -	$ -
1740	UG Conductor	$ 215,252		$ 215,252	$ -		$ -	$ -
1611	Computer Software (Formally known as Account 1925)			$ -	$ -		$ -	$ -
1612	Land Rights (Formally known as Account 1906)			$ -	$ -		$ -	$ -
1805	Land	$ 89,160		$ 89,160	-$ 32,744		-$ 32,744	$ -
1806	Land Rights	$ 154,128		$ 154,128	$ 221,270		$ 221,270	$ -
1808	Buildings	$ 24,624,967	$ 621	$ 24,624,346	$ 1,334,636		$ 1,334,636	$ 577,035
1810	Leasehold Improvements	$ -		$ -	$ -		$ -	$ -
1815	Transformer Station Equipment >50 kV	$ 5,491,722		$ 5,491,722	$ 3,017,409		$ 3,017,409	$ 275,973
1820	Distribution Station Equipment <50 kV	$ 7,812,618		$ 7,812,618	$ 34,369,840		$ 34,369,840	$ 2,780,627
1825	Storage Battery Equipment	$ 13,722		$ 13,722	$ -		$ -	$ -
1830	Poles, Towers & Fixtures	$ 10,446,415		$ 10,446,415	$ 18,096,810		$ 18,096,810	$ 2,578,690
1835	Overhead Conductors & Devices	$ 8,345,730		$ 8,345,730	$ 10,200,744		$ 10,200,744	$ 811,945
1840	Underground Conduit	$ 2,546,031		$ 2,546,031	$ 2,898,110		$ 2,898,110	$ 1,091,561
1845	Underground Conductors & Devices	$ 11,437,100		$ 11,437,100	$ 4,890,424		$ 4,890,424	$ 174,831
1850	Line Transformers	$ 9,204,093		$ 9,204,093	$ 8,328,910		$ 8,328,910	$ 1,302,668
1855	Services (Overhead & Underground)	$ 4,460,589		$ 4,460,589	$ 4,218,742		$ 4,218,742	$ 517,876
1860	Meters			$ -	$ 216,522		$ 216,522	$ 206,980
1860	Meters (Smart Meters)	$ 4,468,973		$ 4,468,973	$ 1,458,116		$ 1,458,116	$ 206,980
1905	Land			$ -	$ -		$ -	$ -
1908	Buildings & Fixtures			$ -	$ -		$ -	$ -
1910	Leasehold Improvements			$ -	$ -		$ -	$ -
1915	Office Furniture & Equipment (10 years)			$ -	$ -		$ -	$ -
1915	Office Furniture & Equipment (5 years)			$ -	$ -		$ -	$ -
1920	Computer Equipment - Hardware	$ 1,361	$ 1,361	$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)			$ -	$ -		$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)			$ -	$ -		$ -	$ -
1930	Transportation Equipment			$ -	$ -		$ -	$ -
1935	Stores Equipment			$ -	$ -		$ -	$ -
1940	Tools, Shop & Garage Equipment			$ -	$ -		$ -	$ -
1945	Measurement & Testing Equipment			$ -	$ -		$ -	$ -
1950	Power Operated Equipment			$ -	$ -		$ -	$ -
1955	Communications Equipment			$ -	$ -		$ -	$ -
1955	Communication Equipment (Smart Meters)			$ -	$ -		$ -	$ -
1960	Miscellaneous Equipment			$ -	$ -		$ -	$ -
1970	Load Management Controls Customer Premises			$ -	$ -		$ -	$ -
1975	Load Management Controls Utility Premises			$ -	$ -		$ -	$ -
1980	System Supervisor Equipment	$ 1,381,611	$ 1,381,611	$ -	$ 3,940,725		$ 3,940,725	$ 387,684
1985	Miscellaneous Fixed Assets			$ -	$ -		$ -	$ -
1990	Other Tangible Property			$ -	$ -		$ -	$ -
1995	Contributions & Grants	-$ 11,161,740		-$ 11,161,740	$ 1		$ 1	$ -
2440	Deferred Revenue				-$ 13,778,024		-$ 13,778,024	-$ 592,500
2005	Property Under Finance Lease			$ -	$ -		$ -	$ -
	Total	**$ 82,672,294**	**$ 1,383,593**	**$ 81,288,701**	**$ 79,381,491**	**$ -**	**$ 79,381,491**	**$ 10,320,351**

	2023	Service Lives				Depreciation Expense					
Account	Description	Average Remaining Life of Assets Existing Before Policy Change [3]	Depreciation Rate Assets Acquired After Policy Change	Life of Assets Acquired After Policy Change [4]	Depreciation Rate on New Additions	Depreciation Expense on Assets Existing Before Policy Change	Depreciation Expense on Assets Acquired After Policy Change	Depreciation Expense on Current Year Additions [5]	Total Current Year Depreciation Expense	Depreciation Expense per Appendix 2-BA Fixed Assets, Column J	Variance [6]
		h	i = 1/h	j	k = 1/j	l = c/h	m = f/j	n = g*0.5/j	o = l+m+n	p	q = p-o
1706	Land Rights		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1725	Poles and Fixtures	41.00	2.44%	45.00	2.22%	$ 39,130	$ -	$ -	$ 39,130	$ 39,130	-$ 0
1730	Conductors	32.00	3.13%	45.00	2.22%	$ 1,997	$ -	$ -	$ 1,997	$ 1,997	-$ 0
1735	UG Conduit	35.00	2.86%	40.00	2.50%	$ 24,858	$ -	$ -	$ 24,858	$ 24,858	-$ 0
1740	UG Conductor	22.00	4.55%	25.00	4.00%	$ 9,784	$ -	$ -	$ 9,784	$ 9,784	$ 0
1611	Computer Software (Formally known as Account 1925)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1612	Land Rights (Formally known as Account 1906)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1805	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1806	Land Rights	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1808	Buildings	36.61	2.73%	28.17	3.55%	$ 672,641	$ 47,373	$ 11,541	$ 731,555	$ 731,555	-$ 0
1810	Leasehold Improvements	-	0.00%	-	0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	24.00	4.17%	40.00	2.50%	$ 228,822	$ 75,435	$ 3,450	$ 307,707	$ 307,707	$ 0
1820	Distribution Station Equipment <50 kV	22.00	4.55%	40.00	2.50%	$ 355,119	$ 859,246	$ 34,758	$ 1,249,123	$ 1,249,123	-$ 0
1825	Storage Battery Equipment	21.00	4.76%	30.00	3.33%	$ 653	$ -	$ -	$ 653	$ 653	-$ 0
1830	Poles, Towers & Fixtures	44.00	2.27%	45.00	2.22%	$ 237,419	$ 402,151	$ 28,652	$ 668,222	$ 668,222	-$ 0
1835	Overhead Conductors & Devices	36.00	2.78%	60.00	1.67%	$ 231,826	$ 170,012	$ 6,766	$ 408,604	$ 408,604	$ 0
1840	Underground Conduit	12.00	8.33%	50.00	2.00%	$ 212,169	$ 57,962	$ 10,916	$ 281,047	$ 281,047	$ 0
1845	Underground Conductors & Devices	23.00	4.35%	40.00	2.50%	$ 497,265	$ 122,261	$ 2,185	$ 621,711	$ 621,711	$ 0
1850	Line Transformers	39.00	2.56%	40.00	2.50%	$ 236,002	$ 208,223	$ 16,283	$ 460,508	$ 456,355	-$ 4,153
1855	Services (Overhead & Underground)	36.00	2.78%	40.00	2.50%	$ 123,905	$ 105,469	$ 6,473	$ 235,847	$ 235,847	$ 0
1860	Meters		0.00%		0.00%	$ -	$ -	$ -	$ -		$ -
1860	Meters (Smart Meters)	11.00	9.09%	15.00	6.67%	$ 406,270	$ 97,208	$ 6,899	$ 510,377	$ 510,377	-$ 0
1905	Land		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1908	Buildings & Fixtures		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1910	Leasehold Improvements		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1915	Office Furniture & Equipment (5 years)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equipment - Hardware		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 22/04)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1930	Transportation Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1935	Stores Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1940	Tools, Shop & Garage Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1945	Measurement & Testing Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1950	Power Operated Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communications Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1955	Communication Equipment (Smart Meters)		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1960	Miscellaneous Equipment		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1970	Load Management Controls Customer Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1975	Load Management Controls Utility Premises		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1980	System Supervisor Equipment	6.00	16.67%	20.00	5.00%	$ -	$ 197,036	$ 9,692	$ 206,728	$ 206,728	$ 0
1985	Miscellaneous Fixed Assets		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1990	Other Tangible Property		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
1995	Contributions & Grants	34.00	2.94%	40.00	2.50%	-$ 328,286	$ 0	$ -	-$ 328,286	-$ 328,286	$ 0
2440	Deferred Revenue		0.00%	40.00	2.50%	$ -	-$ 344,451	-$ 7,406	-$ 351,857	-$ 351,857	-$ 0
2005	Property Under Finance Lease		0.00%		0.00%	$ -	$ -	$ -	$ -	$ -	$ -
	Total					$ 2,949,574	$ 1,997,926	$ 130,209	$ 5,077,709	$ 5,073,556	-$ 4,153

APPENDIX C

PUC Distribution Inc.

Distribution System

Plan (“DSP”)

PUC’s DSP has been uploaded as a separate file.

PUC Distribution Inc.

Distribution System Plan

2023 Cost of Service Application

Historical Period:

2018 – 2022

Forecast Period:

2023 – 2027

August 31, 2022

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ACRONYMS

Acronym	Meaning
ACA	Asset Condition Assessment
AFT	Affordability Fund Trust
AM	Asset Management
AMI	Advanced Metering Infrastructure
AMP	Asset Management Process
ASTM	American Society for Testing and Materials
CAIDI	Customer Average Interruption Duration Index
CAPEX	Capital Expenditure
CDM	Conservation Demand Management
CHI	Customer Hours Interrupted
CI	Customers Interrupted
CIA	Connection Impact Assessment
CMI	Customer Minutes of Interruption
COP	Cost of Power
COS	Cost of Service
DA	Distribution Automation
DAI	Data Availability Indicator
DART	Development Assistance Review Team
DER	Distributed Energy Resources
DGA	Dissolved Gas Analyses
DS	Distribution Station
DSC	Distribution System Code
DSP	Distribution System Plan
EOL	End-of-Life
EMS	Energy Management System
ESA	Electrical Safety Authority
ESG	Environmental, Social, and Governance
ESPI	Energy Service Provider Interface
FLIR	Fault Location, Isolation and Restoration
FTTH	Fibre to the Home
GIS	Geographical Information System
GS	General Service
HI	Health Index
HONI	Hydro One Networks Inc.
HOSSM	Hydro One Sault Ste. Marie
HV	High Voltage
HVAC	Heating, Ventilation, and Air Conditioning
ICM	Incremental Capital Module
IEEE	Institute of Electrical and Electronics Engineers
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
IT/OT	Information Technology and Operational Technology systems
KPI	Key Performance Indicator
LDC	Local Distribution Company

Acronym	Meaning
LOS	Loss of Supply
LV	Low Voltage
MED	Major Event Days
METSCO	METSCO Energy Solutions Inc.
MIST	Metering Inside the Settlement Timeframe
MUS	Mobile Unit substation
NA	Needs Assessment
NAESB	North American Energy Standards Board
NERC	North American Electric Reliability Corporation
NMS	Network Management System
NRCan	Natural Resources Canada
O&M	Operations and Maintenance
OEB	Ontario Energy Board
OGCC	Ontario Grid Control Centre
OH	Overhead
OLG	Ontario Lottery and Gaming Corporation
OMS	Outage Management System
PUC	PUC Distribution Inc.
REG	Renewable Energy Generation
RFP	Request for Proposal
RIP	Regional Infrastructure Plan
RRF	Renewed Regulatory Framework
ROE	Return on Equity
ROW	Right of Way
RRP	Regional Planning Process
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
SQR	Service Quality Requirements
SSG	Sault Smart Grid
TDR	Time Domain Reflectometry
TS	Transformer Station
UG	Underground
UFLS	Under-Frequency Load Shedding
VVO	Voltage/VAR Optimization

5.2 DISTRIBUTION SYSTEM PLAN

Distributors are encouraged to organize the required information using the section and subsection headings indicated from here onwards. Distributors are also encouraged to structure the application so that all DSP appendices and supporting materials are included after the main DSP body text, to facilitate review.

The DSP's duration is a minimum of ten years in total, comprising of an historical period and a forecast period. The historical period is the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. For distributors that have not filed a DSP within the past five years, the historical period is from the test year of a distributor's last cost or service application to the bridge year. The forecast period is the last five years of the DSP duration, consisting of five forecast years, beginning with the test year.

PUC Distribution Inc. (PUC) 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 April 18, 2022 (Filing Requirements) as part of its 2023 Cost of Service Application (the Application).

The DSP is a stand-alone document that is filed in support of PUC'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 2018 to 2022, with 2022 being the bridge year, and a forecast period of 2023 to 2027, with 2023 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 PUC is $135,000 and detailed descriptions of specific projects and 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 Filing Requirements.

5.2.1 Distribution System Plan Overview

The distributor must provide a high-level overview of the information filed in the DSP, which should include capital investment highlights and changes since the last DSP. Utilities are encouraged not to repeat details contained in the DSP, but rather provide a broad overview. A distributor should list out the objectives it plans to achieve through this DSP. This DSP will be used to inform and potentially support any requests for incremental capital module (ICM) funding during the 5-year DSP forecast period.

5.2.1.1 Description of the Utility Company

5.2.1.1.1 Service Area and Customers

PUC is licenced to distribute electricity in its service territory which includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. As shown in Figure 5.2-1, PUC's service territory covers a service area of approximately 342 square kilometers.

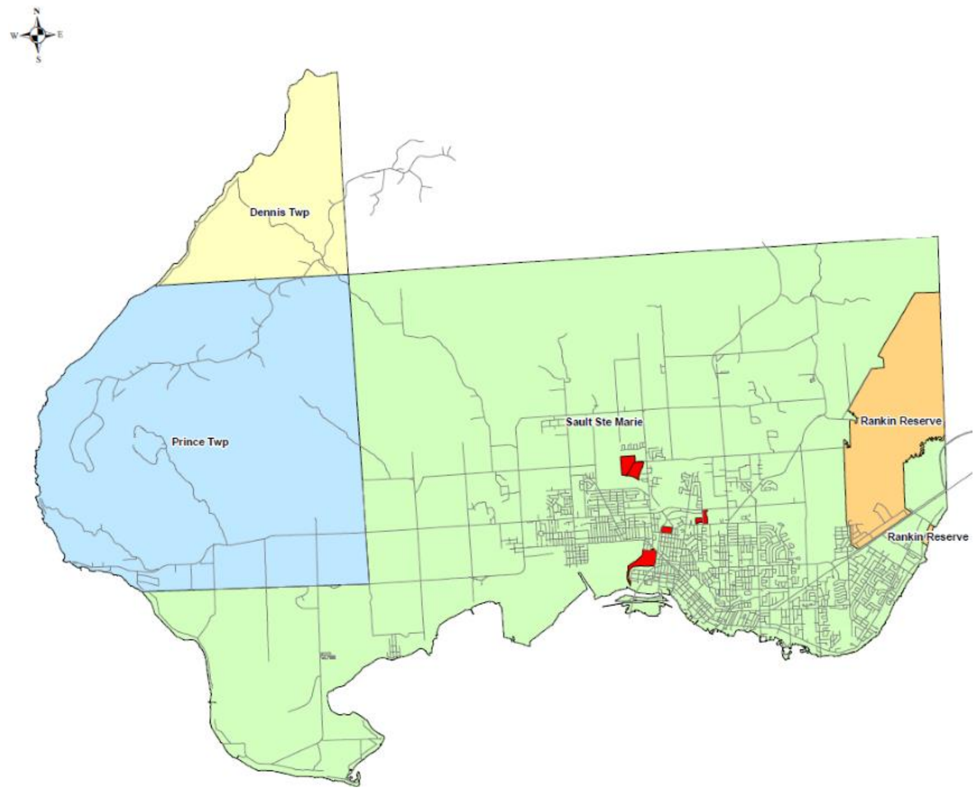


Figure 5.2-1: Map of Distribution Service Territory[1]

PUC's service area is made up of approximately 284 square kilometres of rural area and 58 square kilometres of urban area, with a combined population of approximately 75,300. In 2021, PUC's service territory included approximately 30,134 residential customers and 3,731 general service customers for a total of approximately 33,865 total customers.

5.2.1.1.2 Mission, Vision, Values, and Goals

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

<u>Mission</u>

PUC's mission is to be a community leader providing safe and reliable utility services.

<u>Vision</u>

[1] Note: the areas shown in red are excluded from PUC's service territory. These areas are served by Algoma Power.

PUC's vision is to be recognized as a progressive electric distribution company committed to improving communities through curiosity and innovation.

Values

PUC's core values are safety, integrity, customer-centric, innovative, and accountable.

Corporate Strategic Goals

PUC's Five-Year Strategic Plan provides clarity, direction, and focus connecting the company's vision for the future to its core strategies and strategic objectives. Customers, Employees, and Shareholders are three areas of strategic focus at the centre of the Five-Year Strategic Plan.

Table 5.2-1: Five-Year Strategic Plan – Areas of Strategic Focus

Area of Strategic Focus	Strategic Long-Term Goals	Strategy to Achieve Success
Customers	Achieve and Maintain an Exceptional Customer Satisfaction Rating	Improve Service Quality Management (Responsive, Entrepreneurial, High Quality) Advance Customer Focus (Customer Satisfaction, Communication)
Employees	Be recognized as one of Canada's top 100 employers A culture of Safety Excellence	Implement Leading Organizational Transformation (Employee Engagement, Operational Excellence, Talent Management) Continuous Improvement of Safety Culture and Performance through our Integration Safety Management System.
Shareholder	Achieve 100% Increase in Sustainable Dividend Revenue to Shareholder Achieve Infrastructure Sustainability Increase Enterprise Value	Develop Business Opportunities Ensure Sustainability of PUC, PUC Services, and PUC Commission (Asset Management, DSP/COS, Financial Plan) Continuous Productivity/Business Process Improvement

The strategic initiatives included in this plan describe the outcomes that PUC aims to achieve and sets the benchmarks for success. PUC's strategic initiatives are related to:

1. Smart Grid,
2. Brand Strategy & Community Relations,
3. Improve Employee Relations, and
4. Expand Services Behind the Meter.

These areas of strategic focus and initiatives are in line with the Corporate Mission, Vision, and Values statements.

5.2.1.2 The Sault Smart Grid Project

The Sault Smart Grid Project (SSG Project) is a locally supported community wide smart grid which will cover PUC's entire service territory. The SSG Project is an innovative project that is expected to transform PUC's distribution system through the integration of Voltage/VAR Optimization, Distribution Automation and Advanced Metering Infrastructure. The SSG Project will deliver direct benefits to customers through reduction in energy consumption and monthly bills, reliability improvements, and improved planning and data reporting systems, and will also deliver significant, direct GHG emissions reductions.

The SSG Project was approved (with conditions) by the OEB on April 29, 2021 as part of the amended Incremental Capital Module (ICM) application filed by PUC for new rates effective May 1, 2022 (EB-2020-0249/EB-2018-0219),[2] and PUC secured significant funding from Natural Resources Canada (NRCan) under the NRCan Smart Grid Program to help fund the project. The bulk of the SSG Project execution is being completed in 2022 so the project can be used and useful by the end of 2022. The final portion of the SSG Project related to the testing and optimization of the project to maximize project benefits is set to occur in the first quarter of 2023.

Additional project details along with an explanation of how PUC is meeting the OEB's conditions of approval, can be found in Section 5.3.6 and throughout this DSP.

5.2.1.3 Capital Investment Highlights

The distributor must provide a high-level overview of the information filed in the DSP, which should include capital investment highlights.

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

Table 5.2-2: Historical Actual and Forecast Capital Expenditures and System O&M ($ '000)

Category	Historical				Bridge Year	Forecast				
	2018	2019	2020	2021	2022[1]	2023	2024	2025	2026	2027
System Access (Gross)	1,890	2,475	2,364	2,154	1,836	2,339	2,672	2,792	2,494	2,357
System Renewal (Gross)[2]	3,599	3,172	3,397	8,918	6,629	4,599	4,240	3,442	3,548	2,567
System Service (Gross)[3]	73	-	-	154	28,713	3,190	127	841	750	5,859
General Plant (Gross)	14	188	124	593	-	577	813	1,033	432	633
Gross Capital Expenses	5,576	5,835	5,884	11,819	37,178	10,705	7,853	8,109	7,224	11,416
Contributed Capital	(431)	(1,112)	(658)	(586)	(7,848)	(593)	(616)	(642)	(612)	(624)
Net Capital Expenses after Contributions	**5,145**	**4,723**	**5,226**	**11,234**	**29,330**	**10,113**	**7,236**	**7,467**	**6,612**	**10,792**
System O&M	6,010	6,302	6,434	6,407	6,680	7,280	7,644	8,026	8,428	8,849

[1] 0 months of actual expenditures included in 2022

[2] OEB Decision and Order. EB-2020-0249/EB-2018-0219 PUC Distribution Inc. April 29, 2021.

[2] The 2021 system renewal amount includes $6.02M of actual spend towards PUC's Substation 16 ICM (EB-2019-0170).
[3] The system service spend of $28.713M in 2022 and $3.190M in 2023 relates to the SSG Project.

5.2.1.3.1 System Access

System access investments are modifications (including asset relocation) to the distribution system PUC is obligated to perform to provide a customer (including a generator customer) or group of customers with access to electricity services via PUC's distribution system. The proposed investments under this category over the forecast period include costs associated with connection of residential and general service customers, metering, subdivision work, city projects, and joint use attachments. For the most part, overall proposed investments in areas of system access follow suit with those of the previous DSP period.

5.2.1.3.2 System Renewal

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of PUC's distribution system to provide customers with electricity services. PUC's system renewal efforts put continued emphasis on established initiatives and programs currently in progress across PUC's stations and linear assets. Planned expenditures over the forecast period address general assets including deteriorated poles, primary distribution cables, and underground infrastructure as recommended in the asset condition assessment (ACA).

Additionally, accelerated programs are in place with two key projects. First, the proposed completion of the long standing 4.16 kV to 12.47 kV Voltage Conversion program in this DSP period will eliminate the last of many complex multi-circuit distribution lines and the need to stock multiple types of equipment. This will allow the retirement of the end-of-life 4.16 kV Substations 4 and 5. Second, PUC will continue to work on its Restricted Conductor Program which aims to eliminate and replace smaller diameter overhead conductor. These conductors are prone to premature failure and require either outages or labour-intensive work methods to operate and maintain safely.

System renewal investments also include station renewal initiatives as it dovetails with both the ACA recommendations and the goals of PUC's SSG Project. The integration of the SSG Project with the DSP is discussed further in Section 5.2.1.4 below.

5.2.1.3.3 System Service

System service investments are modifications to PUC's distribution system to ensure the distribution system continues to meet PUC operational objectives while addressing anticipated future customer electricity service requirements. Over the forecast period, PUC is proposing a new station build to address constraints in PUC's ability to connect current and future anticipated loads in the western side of the service territory. The capacity issues in the westerly portion of PUC's service territory are discussed further in Section 5.2.1.4 below.

Additionally, with an aim to enhance system service, improve system efficiency and maintain power quality, PUC has pursued its SSG Project in parallel through a separate ICM Application. The SSG Project is currently under construction and is expected to be used and useful by the end of 2022. In Q1 2023 the project team will be completing the tuning and optimization to maximize benefits of improved reliability and reduced energy consumption through the implemented Distribution Automation and Voltage/VAR Optimization solutions.

5.2.1.3.4 General Plant

General plant investments are modifications, replacements, or additions to PUC's assets that are not part of the distribution system; including land and buildings; tools and equipment; rolling stock; and electronic devices and software used to support day-to-day business and operations activities.

General plant investments proposed in the forecast period have increased materially in comparison to the historical period due to two main factors. First, building infrastructure renewal needs at PUC's single work centre located at 500 Second Line in Sault Ste. Marie are growing as the building begins to age and a number of smaller capital initiatives are required to ensure the safe and reliable continuation of PUC's operations. Second, in the area of Information Technology and Operational Technology systems (IT/OT), a fairly significant capital project is proposed to migrate PUC's geographical information system (GIS) to a newly supported Utility Network (UN) platform as the existing system is 25 years old, is approaching end of useful life and will no longer be supported by the vendor in the next three years as they move exclusively to a UN platform.

5.2.1.3.5 Contributed Capital

Contributed capital refers to the capital contributions received from third parties such as customers, developers, municipalities, and/or governments, towards capital projects. Although most capital contributions received tend to be for system access projects, contributions can sometimes be available for system renewal, system service or general plant projects as well.

Capital contributions over the forecast period are informed by both ongoing engagements with third parties and historical trends (excluding large one-time project contributions such as the NRCan contribution towards the SSG Project in 2022).

5.2.1.4 Key Changes since Last DSP Filing

The distributor must provide a high-level overview of the information filed in the DSP, which should include changes since the last DSP.

Several key changes and challenges presented themselves in the historical 2018-2022 DSP period, some of which are expected to impact plans over the 2023-2027 period. These are discussed further below:

- **Sault Smart Grid Project Integration with DSP Plans** - The exact timing of the submission and approval by OEB of the ICM application for the SSG Project was unknown at the time of preparation for the previous DSP filing. As a result, any potential synergies between renewal of assets through the SSG Project and renewal through routine planned capital spending in the DSP remained an unknown. In 2021, after approval of the SSG Project was granted, PUC executed contingency plans that adjusted the priority of renewal activities to better align with SSG Project. As such, the addition of a new distribution station (Substation 22), which was originally planned for 2020-2022 in the last DSP was deferred and substituted with the renewal of six transformers and primary switchgear at three of PUC's existing distribution stations (Subs 2, 11 and 20) that were identified as having warranted asset renewal needs. This resulted in overall renewal cost savings due to the synergies leveraged through achieving both aged asset renewal with reduced future requirements for stations investment and the NRCan funding eligibility benefits of the SSG Project (the NRCan grant will cover approximately 25% of the project value). Additional information on how the SSG Project fits within PUC's overall capital investment priorities can be found in Section 5.3.6.

- **COVID-19 Pandemic** - The COVID-19 Pandemic presented ongoing challenges in delivering the DSP over the 2018-2022 period. Whether this will persist into the 2023-2027 period is yet to be seen, however, it is possible that difficulties with labour mobility to execute work due to social distancing and lockdown requirements, and supply chain and equipment deliveries delays may persist over the forecast period. Careful formal planning well in advance for each project with COVID-19 as an explicit element in those plans led to successes for PUC in 2020-2021 and will continue to be PUC's approach until such time that it is no longer a material risk.

- **Localized Capacity Constrains in West End of Service Territory** - In 2020 and 2021, PUC saw a continued upward trend in requests for potential connection of several large and medium sized commercial customers near the western edge of its service territory, close to the City's airport. The upward trend in requests in this area was not historically seen by PUC. A cannabis growing facility and an airport hotel are amongst the applicants that PUC has been in recent discussions with, along with the city planners and local developers. Because of its proximity to the edge of the distribution system, the circuits in the area are primarily single phase, but the interested customers require three phase circuits. In addition, these existing circuits are generally at or above their designed loading limits, as is explained further in Section 5.3.2.2.1. To accommodate this localized demand, PUC has proposed a new station build during the forecast period of this DSP. However, this new station presents a challenge as it will divert some necessary funds away from asset renewal needs identified in the ACA. Balancing these capacity and system renewal needs has been carefully considered by PUC. For example, PUC is proposing to defer the renewal of critical switching assets at its two transformer stations as identified in the ACA. These costs have been pushed out to the next cost of service (COS) period to help accommodate the new station build while also allowing PUC to undertake careful planning on how best to address these high-cost renewals, in the context of full station rebuilds.

As can be seen in PUC's financial summaries, variance analysis, and in the proposed plan going forward, PUC has made necessary adjustments to keep costs within the planned financial limits while achieving outcomes consistent with both OEB mandated and PUC long-term planning goals and objectives.

5.2.1.5 DSP Objectives

A distributor should list out the objectives it plans to achieve through this DSP.

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

- An overview of PUC's asset management objectives and goals;
- A review of PUC's operational performance in the five-year historical period;
- A preview of PUC's planned expenditures for the forecast period aimed at improving its asset-related performance to achieve the four performance outcomes established by the OEB; and
- A detailed justification of PUC's planned capital expenditures in the Test Year.

This DSP covers a planning horizon of five years starting in the 2023 Test Year. Employing this long-term approach requires PUC to consider future customer needs and any required changes to its distribution system in advance. This approach enhances PUC's ability to plan ahead and respond to evolving customer needs in a timely manner, while managing and leveling the impacts of expenditures on consumer rates to maintain affordability of its service. The DSP recognizes PUC's responsibilities and commitments to provide customers with reliable service by ensuring that its asset management activities focus on the performance outcomes 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 government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. **Financial Performance**: financial viability is maintained; and savings from operational effectiveness are sustainable.

5.2.2 Coordinated Planning with Third Parties

A distributor must demonstrate that it has met the OEB's expectations in relation to coordinating infrastructure planning with customers, (e.g., large customers, subdivisions developers, and municipalities), the transmitter, (e.g., Regional Infrastructure Planning), other distributors, the Independent Electricity System Operator (IESO) (e.g., Integrated Regional Resource Planning) or other third parties where appropriate. A distributor should explain whether the consultation(s) affected the distributor's DSP as filed and if so, a brief explanation as to how.

For consultations that affect the DSP, a distributor should provide an overview of the consultation, relevant material used in the consultation, and where a final deliverable is available, attach a copy of the final deliverable (e.g., Integrated Regional Resource Planning, Regional Infrastructure Planning, Renewable Energy Generation Plan, Municipal Plans, and Connection & Cost Recovery Agreements)

A description of any consultation(s) should include: The purpose of the consultation, whether the distributor initiated the consultation or was invited to participate in it, and the other participants in the consultation process (e.g., customers, transmitter, IESO).

A description of any consultation(s) should include: The purpose of the consultation, whether the distributor initiated the consultation or was invited to participate in it, and the other participants in the consultation process (e.g., customers, transmitter, IESO).

Further, a distributor is required to identify if there are any inconsistencies between its DSP and any current Regional Plan. If there are any inconsistencies, the distributor shall explain the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan.

Before preparing this DSP, PUC consulted with all stakeholders affected by the DSP, with the objective of accurately assessing their needs and to confirm the adequacy of existing capacity of the distribution system; so that the investments could be focused into areas of the greatest need. The results of coordinated planning with third parties are documented in this section, by addressing the following questions for each consultation:

- the purpose of the consultation;
- whether the distributor initiated the consultation or was invited to participate in it;
- the other participants in the consultation process;
- the nature and prospective timing of the final deliverables, that are expected to result from or otherwise be informed by the consultation;
- a brief description of the consultation; and
- an indication of whether the consultation has or is expected to affect the distributor's DSP as filed and if so, a brief explanation as to how.

The stakeholders consulted by PUC during preparation of the DSP include customers, municipal governments, developers and utilities, the IESO and telecommunication companies.

5.2.2.1 Customer Engagement

Purpose of Consultation

PUC conducts customer consultations to share information with customers, to gather customers' opinions on its services and to ensure that the customers' needs and preferences are taken into consideration during the development of long-term plans. PUC has conducted both formal and informal community engagement activities with its customers over the last five five years.

Initiation and Participation

All consultations with customers were initiated by PUC, either through its own staff or through consultants with expertise in polling and gathering public input. The participants for the consultations included residential and general service customers.

Nature and Timing of Final Deliverables

Surveys were used to educate, inform, and solicit input from customers regarding PUC's current and future plans. PUC engaged its customers through eight surveys since its last cost of service filing; two UtilityPULSE Customer Satisfaction surveys in 2019 and 2021, four Customer Pulse surveys in 2020, and two cost of service-related surveys in 2021 and 2022. The UtilityPULSE surveys were conducted in September of 2019 and 2021 respectively as telephone interviews, whereas the Customer Pulse online surveys were distributed to customers four times throughout 2020. Phase 1 of the cost of service survey took place in September/October 2021, and Phase 2 was completed in June 2022. The final deliverables from these consultations are included in Appendix N of Exhibit 1.

Brief Description of Customer Engagements

PUC believes that customer engagement is the backbone of its community-driven operations. PUC recognizes that providing opportunities for customers to share their feedback will not only strengthen its relationship with customers, but also improve the overall customer experience.

As a local distribution company (LDC), PUC understands that its role in planning for the future of the electrical distribution system involves more than just measuring equipment service life. It requires including customers in the planning process to ensure that they have considered their needs and preferences when it comes to developing long-term plans. To that end, PUC is committed to growing and expanding on the success of its existing community service and customer engagement initiatives.

PUC has completed formal and informal community engagement activities with its customers over the last five years, with the most recent engagement corresponding to the cost of service related customer surveys undertaken in September/October 2021 and June 2022. These engagement opportunities identified a number of customer needs and preferences, along with room for improvements to be made. Key learnings that emerged through the following engagements included:

UtilityPULSE Customer Satisfaction surveys:

- Reliability and investment in the grid to reduce outages, reducing environmental impacts, and equipment maintenance and upgrades were of importance to customers in the 2019 survey whereas digitization, improved communication methods, and lower prices were of importance to customers in 2021.
    - PUC received a Credibility and Trust rating of 87% and an Overall Satisfaction rating of 94% in 2019.

Customer Pulse surveys:

- Customers wanted PUC to focus on energy saving initiatives for them, with 97.39% customers agreeing that energy savings is important to them. Similarly, customers also wanted PUC to focus on reducing its carbon footprint.

- Customers wanted to improve their communication experience with PUC, especially about outages. 72.12% customers stated that they would pay $0.50 to $2.00 on bills to improve reliability, efficiency, and communications.

Cost of Service-related surveys:

- As with the previous DSP period, customers overwhelmingly remained focus on seeing both rates and service levels being maintained. There is some interest in seeing expanded support for renewables and REG, however this was limited in the feedback received.
- In a recent customer survey completed by PUC, feedback indicated that:
    - 90.44% of customers were either satisfied or very satisfied with PUC as their electrical services provider.
    - The two top priorities of customers consisted of delivering reasonably priced electricity services (59.31%) and ensuring safe and reliable electricity services (32.84%).
    - Customers identified that investing in the electricity grid to reduce the frequency and duration of power outages (34.80%) and investing in infrastructure that will lower carbon footprint (33.95%) are two of the most important strategic priorities.

Consultations Impact on this DSP

Customer feedback has been integrated into the preparation of this DSP. Based on customers' need for better communications, digitization, energy savings, and improved reliability, PUC took active steps to address these issues and improve its customer experience. To begin with, PUC developed a mobile app called MyPUC App in 2021 to help customers manage their usage and accounts, receive up-to-date information on power and/or water disruptions, and enable two-way communication with PUC. Since the app launch, PUC has noticed a reduction in customer calls during outages. In addition, to improve its communications experience for customers, PUC has upgraded its website and engages with customers on multiple social media platforms such as Twitter, Facebook, LinkedIn etc. through Social Sprout. PUC will continue to engage with customers through these platforms over the forecast period.

Similarly, to push its digitization strategy forward, PUC aims to go paperless by 2024. PUC has already removed paper paystubs, decreased daily printing, encouraged customers to opt-in for pre-authorized online payments, and increased online payments to the vendors. PUC's mobile app has also helped promote e-billing to customers. PUC also recognizes that cyber security should be focused on with increased digitization and has made significant investment in cyber security infrastructure and personnel.

To improve reliability and efficiency of the grid, PUC has made investments through the SSG Project that will upgrade equipment, reduce the number of outages and response time to outages, and improve energy consumption. PUC has also purchased electric vehicles to reduce its carbon footprint.

Lastly, while a vast majority of PUC customers are satisfied and pleased with the power supply reliability, many customers are also sensitive to an increase in retail rates. Customer sensitivity to the retail rate increases has been taken into consideration in this DSP, by accepting some risk of asset failures in service, by deferring several projects in the asset renewal category, and only including a relatively small number of projects in the current investment plan, which present the highest risk of asset failures during the next five years.

5.2.2.2 Municipal Government, Developers and Utility Consultations

Purpose of Consultation

PUC interacts with the City of Sault Ste. Marie administration 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. PUC staff attend formal meetings annually with the City and other municipal stakeholders such as developers and local utilities (water, gas, oil), to review budgets and work plans for the coming year and the next five years. Other ad-hoc coordination sessions occur on an as needed basis with the City and development stakeholders to look for synergies on specific projects and initiatives such as subdivision, commercial, and institutional developments.

Initiation and Participation

The annual coordination meetings are generally initiated by the City's administration and PUC along with other utilities participating in them. For large developments in the city, PUC is invited to Development Assistance Review Team (DART) meetings on a regular basis early in the planning stage. The meetings include active participation from commercial, institutional, and residential developers active in the community. These meetings also provide an excellent opportunity for open dialogue between important stakeholders to learn about and discuss their current and upcoming plans. Additionally, PUC is included and invited to comment on all committee of adjustments, rezoning, severance, and building applications, allowing PUC to identify requirements early in the development stage. Other important stakeholders in these meetings include general service customers and other utilities including gas and telecommunications.

Nature and Timing of Final Deliverables

The final deliverables from these consultations are in the form of development information such as plans and associated schedules, which are received during the meetings.

Brief Description of the Consultation

Participating in these consultations allows PUC to learn about and understand upcoming projects in the community, which then leads PUC to plan and size its infrastructure appropriately to support the projects. Although detailed information about the upcoming projects is not always available five years in advance, these consultations do provide qualitative indication of the volume of anticipated projects involving new customer connections, subdivision developments, and line relocates.

These meetings also offer some glimpse into potential for future Distributed Energy Resources (DER) or Renewable Energy Generation (REG) projects and smart grid developments. At present there are no discussions indicating any such projects are being proposed.

Consultations Impact on this DSP

The information obtained from the municipality, developers and other utilities has been used as an input to identify investment level requirements in the system access category proposed in this DSP (i.e., subdivisions, city projects, joint use, and general services).

5.2.2.3 Regional Planning Process

The Regional Planning Process (RPP) 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, Hydro One Networks Inc. (HONI) conducts a Need Assessment and develops a Regional Infrastructure Plan that involves representatives from the Independent Electricity System Operator (IESO), and LDCs of the planning region.

PUC is part of the East Lake Superior Region. As illustrated in Figure 5.2-2 below, this region extends from the Township of Dubreuilville in the North to the town of Bruce Mines in south and includes the city of Sault Ste. Marie and the township of Chapleau. This planning region includes the following participants:

- Algoma Power Inc.
- PUC Distribution Inc.
- Chapleau Public Utilities Corporation
- Hydro One Networks Inc. (distribution)
- Hydro One Networks Inc. (transmission)
- Hydro One Sault Ste. Marie (HOSSM) LP (transmission)
- IESO

Figure 5.2-2: East Lake Superior Planning Region[3]

The first regional planning cycle for the region was completed in December 2014 with the publishing of the Needs Assessment (NA) Report, which identified a number of potential needs and

[3] Hydro One Networks Inc. East Lake Superior Regional Planning. https://www.hydroone.com/about/corporate-information/regional-plans/east-lake-superior

recommendations for the near and medium-term timeframes. Further coordinated regional planning did not proceed following the publication of the NA report.

The second regional planning cycle for the East Lake Superior Region was initiated in April 2019 with a NA, which is in accordance with the RPP, which states that the regional planning cycle should be revisited at least every five years. The East Lake Superior Region NA report was published by HONI in June 2019 (attached in Appendix B). This was followed by the Scoping Assessment (SA) in October 2019 (attached in Appendix C), completion of the East Lake Superior Region Integrated Regional Resource Plan (IRRP) in April 2021 (attached in Appendix D), and publication of the final Regional Infrastructure Plan (RIP) in October 2021 (attached in Appendix E). HOSSM and Algoma Power also completed a separate Local Planning report specifically to address the local needs of the Batchawana and Goulais Bay area.

Through the second regional planning cycle, several needs were identified in the East Lake Superior Region including station and transmission capacity needs, restoration needs, and end-of-life needs. Further needs and considerations were also identified in the SA Report relating to embedded generation and expiration of generation contracts in the Sault Ste. Marie sub-system, as well as the potential construction of an industrial ferrochrome production facility in the city of Sault Ste. Marie beginning in 2025. Since the industrial load would directly connect to the high voltage transmission system, it is being studied further as part of the IESO's bulk replanning study.

The 2021 RIP provided the following summary of needs and recommended plans for East Lake Superior Planning region in the near and mid-term (i.e., over the next ten years):

Table 5.2-3: East Lake Superior Planning Region – Needs and Action Plan

No.	Need	Recommended Action Plan	Planned ISD	Budgetary Estimate
1	Eliminate/Minimize manual communication between IESO and OGCC when arming Third Line Instantaneous Load Rejection Scheme	Enable remote arming of Third Line Instantaneous Load Rejection Scheme via ICCP line between IESO's EMS and HONI's NMS	2021	$10K
2	Third line TS: End of life protection	Replace end of life protection per current standard	2022	$0.8M
3	Echo River TS: Transmission Supply Reliability and end of life breaker	Install 'hot' spare transformer and replace end of life breaker	2023/ 2024	$11.5M
4	115kV Sault No.3: end of life structures and conductor	Replace end of life structure and conductor per current standard	2024	$54.4M
5	Batchawana TS: End of life components	Refurbish Batchawana TS with MUS provision	2024	$6.2M
6	Goulais TS: End of life components	Refurbish Goulais TS with MUS provision	2024	$13.4M
7	Patrick St. TS, Algoma No.1 overload	Implement Automatic Load Rejection Scheme at Patrick St. TS	2023	$1.2M
8	Patrick St. TS: End of life 115kV breaker	Replace end of life 115kV breakers 'like for like' per current standard	2024	$3.3M

No.	Need	Recommended Action Plan	Planned ISD	Budgetary Estimate
9	Third Line TS: T2 end of life	Replace end of life T2 'like for like' per current standard	2025	$16.4M
10	Northern Ave TS: end of life component replacement	Replace end of life T1 with smaller MVA unit and protection relays per current standard	2025	$2.5M
11	Anjigami/Hollingsworth TS: Transformer overload	Build new 115/44kV Station - HOSSM to work with API to continue to develop solutions	2024/ 2025	$30M
12	Clergue TS: End of life metal clad switch gear	Replace end of life switch gear 'like for like' per current standard	2026	$5.2M
13	Hollingsworth TS: End of life Protection relay	Replace end of life protection per current standard	2025	$1.1M
14	D.A. Watson TS: End of life metal clad switch gear	Replace end of life switch gear 'like for like' per current standard	2026	$9.2M

The needs and recommended action plan mentioned in Table 5.2-3 do not directly involve PUC, and as a result, there is no impact on the capital investments proposed in this DSP. PUC will continue to actively participate in engagement with all relevant stakeholders for regional planning processes to ensure it continues to respond appropriately to the needs of its customers and industry partners. PUC also notes that there are no inconsistencies between this DSP and the current Regional Plan.

5.2.2.4 Telecommunication Entities

On January 11, 2022, the OEB issued further guidance to the regulation that requires distributors to consult with any telecommunications entity that operates within its service area when preparing a capital plan for submission to the OEB, for the purpose of facilitating the provision of telecommunications services, and include information in its capital plan.

Per the new telecom regulations, the distributor should include the following information in its capital plan:

- *The number of consultations that were conducted and a summary of the manner in which the distributor determined with whom to consult.*
- *A summary of the results of the consultations.*
- *A statement as to whether the results of the consultations are reflected in the capital plan and, if so, a summary as to how.*

Consultations

PUC has an established Joint Use program within its service territory that allows for other pole attachments such as cable, telephone, fibre, etc. The joint use agreements set out the required design standards to ensure the safety of employees and the public.

PUC also informs service providers, including telecommunication companies and gas companies, of its planned capital projects to ensure that respective parties are aware of the plans for budgeting purposes and to allow opportunities to coordinate work between companies to gain efficiencies. PUC typically provides a letter containing a list of major projects along with brief scope descriptions and sketches to service providers on an annual basis. PUC also meets with the service providers on an annual basis as part of a municipally organized coordination meeting to discuss plans and any potential opportunities for coordination. Although PUC formally engages telecommunication companies on an annual basis, informal conversations occur on a regular basis, initiating around system access. The following table summarizes the formal consultations with communications companies that PUC has conducted and been involved in since the last DSP filing:

Table 5.2-4: Summary of Consultations

Date of Consultation	Consultation Overview	Participants
February 12, 2020	PUC distributed a letter discussing PUC's proposed 2020 capital projects. The letter included brief project descriptions and associated sketches.	▪ Bell Canada ▪ Shaw Communications ▪ Ontera ▪ City of Sault Ste. Marie
November 30, 2018	PUC distributed a letter discussing PUC's proposed 2019 capital projects. The letter included brief project descriptions and associated sketches.	▪ Bell Canada ▪ Shaw Communications ▪ Ontera ▪ City of Sault Ste. Marie
December 4, 2017	PUC distributed a letter discussing PUC's proposed 2018 capital projects. The letter included brief project descriptions and associated sketches.	▪ Bell Canada ▪ Shaw Communications ▪ Ontera ▪ City of Sault Ste. Marie

<u>Result of Consultations</u>

The province has mandated for improved broadband access by 2025, which incentivises communication companies to extend their infrastructure to rural areas to better service customers. This initiative will increase Joint Use activity in PUC's service territory, particularly in the westerly Prince Township area. Increased Joint Use costs are expected between 2023 and 2025 to accommodate this initiative.

PUC has also been approached recently to have other wireless attachments on its poles, including cameras, WIFI extenders, and 5G. However, since these discussions are still preliminary and agreements are not yet in place, PUC does not anticipate any costs associated with this work during this DSP period.

Communicating with telecommunication companies on a project-by-project basis provides all parties an opportunity to effectively plan for an economical solution.

<u>Consultation Effects on the DSP</u>

Telecommunication companies have informed PUC that they have not applied for projects within PUC's territory that would have material effect on PUC. Additionally, telecommunication companies have informed PUC that they do not have any finalized plans to expand their systems in PUC's territory that would materially impact PUC.

PUC will continue to regularly communicate with service providers over the forecast period to identify and promote any opportunities for coordination between parties.

5.2.2.5 CDM Engagements

2021 CDM Guidelines: In the case of a CDM activity that is driven by a specific customer and funded by a customer capital contribution, the distributor should provide details on engagement with the customer on options, and the customer's preference (if applicable).

Although PUC continues to consult with its stakeholders including customers, consultants, other distributors and the IESO to effectively promote and deliver conservation and demand management (CDM) programs, PUC does not anticipate any major impact of CDM programs on the DSP. Additional information on PUC's CDM programs is included in Section 5.3.5.

5.2.2.6 Renewable Energy Generation

A distributor is expected to coordinate with the IESO in relation to REG investments and confirm if there are no REG investments in the region.

If there are REG investments proposed in the DSP, a distributor is expected to demonstrate that it has coordinated with the IESO, other distributors, and/or transmitters, as applicable, and that the investments proposed are consistent with a Regional Infrastructure Plan. This coordination is demonstrated by a comment letter provided by the IESO, to be filed with the DSP.

A Renewable Energy Generation (REG) Plan outlining the plan to support connection of renewables and smart grid technologies for the period 2023-2027 was prepared by PUC and submitted to IESO on October 26, 2021. The plan indicates that the PUC grid is currently very well positioned to support forecast REG connections over the next five years with no associated infrastructure investment required during that period. The IESO provided a comment letter on November 4, 2021, upon completion of its review. The plan and response letter are attached in Appendix F and Appendix G.

5.2.2.7 Green Button

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.

PUC has selected an integrated business partner through a competitive request for proposal (RFP) which will assist PUC and third-party vendors in providing positive outcomes to PUC's end user customers. This will help PUC in the drive for certification and implementation of Green Button which ensures the solutions meet not only PUC's specific needs, which include digitization, but also the regulatory requirements by November 1, 2023.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Distribution System Plan

Distributors are expected to summarize objectives for continuous improvement (e.g., reliability improvement, number of replaced assets, and other desired outcomes) the distributor set out to address in its last DSP, and to discuss whether these objectives have been achieved or not. For objectives not achieved, a distributor should explain how it affects the current DSP period and, if applicable, improvements a distributor has implemented to achieve the objectives set out in DSP Section 5.2.1.

In order to continually improve its operating performance, PUC continually measures and monitors its performance. The performance measures employed by PUC in measuring its operating performance have evolved over the years and are currently fully aligned with OEB's "Scorecard – Performance Measures" for electricity distributors, as listed below:

- service quality;
- customer satisfaction;
- safety;
- system reliability;
- asset management;
- cost control;
- connection of renewable generation; and
- financial ratios.

Where applicable, the performance measures included on the scorecard have an established minimum level of performance to be achieved. The scorecard is designed to track and show PUC's performance results over time and helps to benchmark its performance and improvement against other utilities and best practices.

A summary of PUC's historical performance as presented in the OEB Performance Scorecards is presented in Table 5.2-5. Each metric provided in Table 5.2-5 and subsections below influences PUC's DSP to achieve the best performance for its customers. The following sections summarize PUC's operating performance during five years from 2017 to 2021.

Table 5.2-5: DSP Performance Measures

Performance Outcome	Measure	Metric	2017	2018	2019	2020	2021	Target[1]
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	96.67%	99.12%	100.00%	100.00%	97.60%	90.00%
		Scheduled Appointments Met on Time	97.62%	99.48%	98.65%	100.00%	99.92%	90.00%
		Telephone Calls Answered on Time	79.88%	77.70%	72.43%	68.88%	71.13%	65.00%
	Customer Satisfaction	First Contact Resolution	99.74%	99.80%	99.82%	99.76%	99.63%	No target
		Billing Accuracy	99.94%	99.97%	99.98%	99.96%	99.97%	98.00%
		Customer Satisfaction Survey	80.00%	80.00%	92.00%	92.00%	88.00%	No target
Operational Effectiveness	Safety	Level of Public Awareness	85.00%	85.00%	85.00%	85.00%	85.00%	No target
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C
		Number of General Public Incidents	0	1	1	2	0	0
		Rate per 100km of line	0.000	0.135	0.135	0.271	0.000	0.076
	System Reliability	Ave. Number of Times that Power to a Customer is Interrupted	1.21	1.28	1.55	1.74	1.32	1.33
		Ave. Number of Hours that Power to a Customer is Interrupted	1.43	1.27	1.45	2.12	1.81	1.38
	Asset Management	Distribution System Plan Implementation Progress	In Progress	100.00%	79.00%	90.00%	104.00%	No target
	Cost Control	Efficiency Assessment	4	4	3	3	3	No target
		Total Cost per Customer	$673	$690	$697	$673	$696	No target
		Total Cost per km of Line	$30,541	$31,338	$31,775	$30,791	$31,915	No target
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation CIA Completed on Time	100.00%	n/a	100.00%	n/a	n/a	No target
		New Micro-embedded Generation Facilities Connected on Time	n/a	n/a	n/a	n/a	n/a	90%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	1.62	1.33	0.94	0.99	0.80	No target
		Leverage: Total Debt (short-term & long-term) to Equity Ratio	2.04	2.02	2.03	2.07	2.09	No target
		Regulatory ROE – Deemed (included in rates)	8.98%	9.00%	9.00%	9.00%	9.00%	No target
		Regulatory ROE - Achieved	1.78%	4.25%	8.87%	8.75%	7.60%	No target

[1] Targets shown are for year 2021.

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

SAIDI & SAIFI in 2019, 2020 and 2021

PUC did not meet its SAIDI and SAIFI performance targets in 2019, 2020 and 2021 primarily due to outages caused by Defective Equipment, Adverse Weather and Foreign Interference. Specifically,

- In 2021, the SAIFI target was missed as a result of Defective Equipment, Adverse Weather and unknown causes that could not be identified following patrols and where circuits were re-energized. Ongoing efforts to improve reliability, including looking for mitigation approaches for the main outage causes and a focus on effective maintenance activities and replacing aging infrastructure.
- In 2020, two major outage causes encountered were attributed to Defective Equipment and Foreign Interference. Defective Equipment was a result of a cable failure on our 34.5 kV and 12.47 kV systems. Foreign Interference was mainly caused by animal contact and motor vehicle accidents.
- In 2019, the SAIDI and SAIFI targets were missed as a result of Adverse Weather and Defective Equipment. Increased storm events in 2019 above the normal rate that did not meet the MED criteria was a major contributor along with aging infrastructure.

Additional information on PUC's historical reliability performance as well as information on PUC's ongoing and planned efforts to improve reliability over the forecast period are included in Sections 5.2.3.2.2 and 5.2.3.2.3 below.

Number of General Public Incidents in 2018, 2019 and 2020

PUC did not meet its general public incident performance targets in 2018, 2019 and 2020:

- In 2020, PUC has two reportable serious electrical incidents because of storm conditions and equipment failure. There were no injuries associated with the incident, and the staff made the necessary repairs. As such, PUC did not meet its performance metric target of one general public incident.
- In 2019, there was one reportable serious electrical incident. A tree loaded with snow contacted a 7200-volt primary line which caused the conductor to break. PUC staff attended the site, installed work protection, and made the necessary repairs to restore power.
- In 2018 there was one reportable serious general public incident related to the felling of a tree by a member of the public. Protective devices integral to public safety operated as designed. PUC staff interacted directly with the party involved in the incident to discuss the details of the event and provide education related to the dangers of contact with distribution system lines.

PUC remains strongly committed to both the safety of staff and the general public. PUC regularly provides its customers with electrical safety information via its website and bill inserts. Additionally, within this DSP period, there are several ongoing and planned efforts to enhance system safety. These efforts include:

- Planned replacement of unsafe poles
- Planned replacement of 4.16 kV equipment that has surpassed its useful life creating increased safety risks
- Planned reconstruction of deteriorated underground vaults and manholes presenting increased safety hazards

- Planned replacement of transformers with PCB contamination >50 ppm presenting health, environmental and safety risks
- Planned removal of restricted conductor to eliminate brittle, undersized coper conductor prone to failure.

Liquidity

Although there are no targets set for PUC's Liquidity metric (i.e., ratio of Current Assets / Current Liabilities), PUC notes a decreasing trend in liquidity over the last five years. This is somewhat misleading since it is being skewed by certain affiliate transactions. Specifically, the current ratio is affected by how PUC funds its capital expenditures and the timing of financing arrangements. Going forward PUC will look at obtaining financing prior to year-end which will shift more of the current liability owing to affiliates to long term debt and improve the presentation of its current ratio.

5.2.3.2 Service Quality and Reliability

Chapter 7 of the OEB's Distribution System Code outlines the OEB's expectations regarding Service Quality Requirements (SQR) for Electricity Distributors. A distributor is required to provide the reported SQRs for the last five historical years. A distributor should also provide explanations for material changes in service quality and reliability, and whether and how the DSP addresses these issues. The OEB expects any five-year declining trends in reliability for SAIDI and SAIFI to be explained. If a distributor has reliability targets established in a previously filed DSP, as described below, any underperformance should also be explained.

A completed Appendix 2-G, documenting both the Service Quality and Service Reliability indicators, must be filed. A distributor must confirm that data is consistent with the scorecard or must explain any inconsistencies.

A summary of performance for the historical period using the methods and measures (metrics/targets) identified and described above, and how this performance has trended over the period. This summary must include historical period data on

- *All interruptions*
- *All interruptions excluding loss of supply*
- *All interruptions excluding Major Events and loss of supply for the following:*
    - *The distribution system average interruption frequency index (SAIFI)*
    - *System average interruption duration index (SAIDI)*

PUC's service quality and reliability performance are detailed further in the following subsections. Service quality and reliability indicators can also be found in Exhibit 2 Appendix 2-G of this COS Application.

5.2.3.2.1 Service Quality Requirements

PUC measures and monitors service quality in accordance with its core value of being responsive to customer needs to ensure continued improvement and achieve a level customer satisfaction. PUC tracks and reports on Service Quality Requirements (SQR) in accordance with Chapter 7 of the OEB's Distribution System Code (DSC).

Table 5.2-6 presents PUC's SQR performance for the historical period.

Table 5.2-6: Historical Service Quality Metrics

Service Quality Metric	2017	2018	2019	2020	2021	Minimum Standards
Low Voltage Connections	96.67%	99.12%	100.00%	100.00%	97.60%	> 90%
High Voltage Connections	100.00%	100.00%	100.00%	100.00%	100.00%	> 90%
Telephone accessibility	79.88%	77.70%	72.43%	68.88%	71.13%	> 65%
Appointments met	97.62%	98.48%	98.65%	100.00%	99.92%	> 90%
Written response to enquiries	99.28%	98.43%	100.00%	100.00%	100.00%	> 80%
Emergency Urban Response	86.59%	92.16%	100.00%	100.00%	93.75%	> 80%
Emergency Rural Response	n/a	n/a	n/a	n/a	n/a	> 80%
Telephone call abandon rate	3.07%	3.66%	4.65%	3.60%	2.87%	< 10%
Appointment scheduling	91.07%	94.70%	78.45%	98.82%	81.15%	> 90%
Rescheduling a Missed Appointment	100.00%	100.00%	100.00%	100.00%	100.00%	> 100%
Reconnection Performance Standard	99.72%	100.00%	100.00%	100.00%	100.00%	> 85%
New Micro-embedded Generation Facilities Connected	n/a	n/a	n/a	n/a	n/a	> 90%
Billing Accuracy	99.94%	99.97%	99.98%	99.96%	99.97%	> 98%

PUC continuously strives to serve customers with the highest excellence, as is indicated by PUC's historical service quality performance. PUC has met the performance target for each performance metric during each of the past five years, except for Appointment Scheduling metric in 2019 and 2021.

- The Appointment Scheduling metric in 2019 was missed as a result of increased demand from Bell Canada installing fibre optic to roughly 30,000 homes in Sault Ste. Marie. This was a large one-time project that impacted performance in 2019, and PUC's performance returned to more traditional levels following completion of this project.
- The Appointment Scheduling metric in 2021 was missed as a result of a higher than normal number of locates and a staff resource vacancy. Since the number of locates are likely to return to more traditional levels over the forecast period, PUC is not proposing any new investments in response to PUC's performance on this metric. Rather, PUC will continue to balance locate requests with staff availability to maintain a balance between improving this metric and keeping costs low for customers.

5.2.3.2.2 Reliability Requirements

The key metrics that PUC 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 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 PUC 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 PUC (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 performance over the 2013-2017 period, excluding LOS and Major Events. This corresponds to a fixed target of 1.38 for SAIDI and 1.33 for SAIFI. No targets are set for CAIDI.

In addition to meeting the fixed performance baseline targets, SAIDI and SAIFI trending is done by comparing the fixed performance baseline targets against the most recent 5-year rolling average (i.e., average of the most recent 5-year performance, updated annually). This information is reported annually as part of the OEB Scorecards.

PUC’s historical performance for SAIDI, SAIFI and CAIDI are shown in the following tables and figures.

Table 5.2-7: Historical Reliability Performance Metrics – All Cause Codes

Metric	2017	2018	2019	2020	2021	Average
SAIDI	1.96	2.34	8.06	3.09	2.29	3.55
SAIFI	1.61	1.75	2.90	2.32	1.62	2.04
CAIDI	1.22	1.34	2.78	1.33	1.41	1.62

Table 5.2-8: Historical Reliability Performance Metrics – LOS and MED Adjusted

Metric	2017	2018	2019	2020	2021	Average
Loss of Supply Adjusted (Including MEDs, Excluding LOS)						
SAIDI	1.96	2.34	7.98	3.09	2.29	3.53
SAIFI	1.61	1.75	2.77	2.32	1.62	2.01
CAIDI	1.22	1.34	2.88	1.33	1.41	1.64
Major Event Days Adjusted (Including LOS, Excluding MEDs)						
SAIDI	1.96	1.27	1.54	2.12	1.81	1.74
SAIFI	1.61	1.28	1.68	1.74	1.32	1.53
CAIDI	1.21	0.99	0.92	1.22	1.37	1.14
Loss of Supply and Major Event Days Adjusted (Excluding LOS and MEDs)						
SAIDI	1.43	1.27	1.45	2.12	1.81	1.62
SAIFI	1.21	1.28	1.55	1.74	1.32	1.42
CAIDI	1.18	0.99	0.94	1.22	1.37	1.14

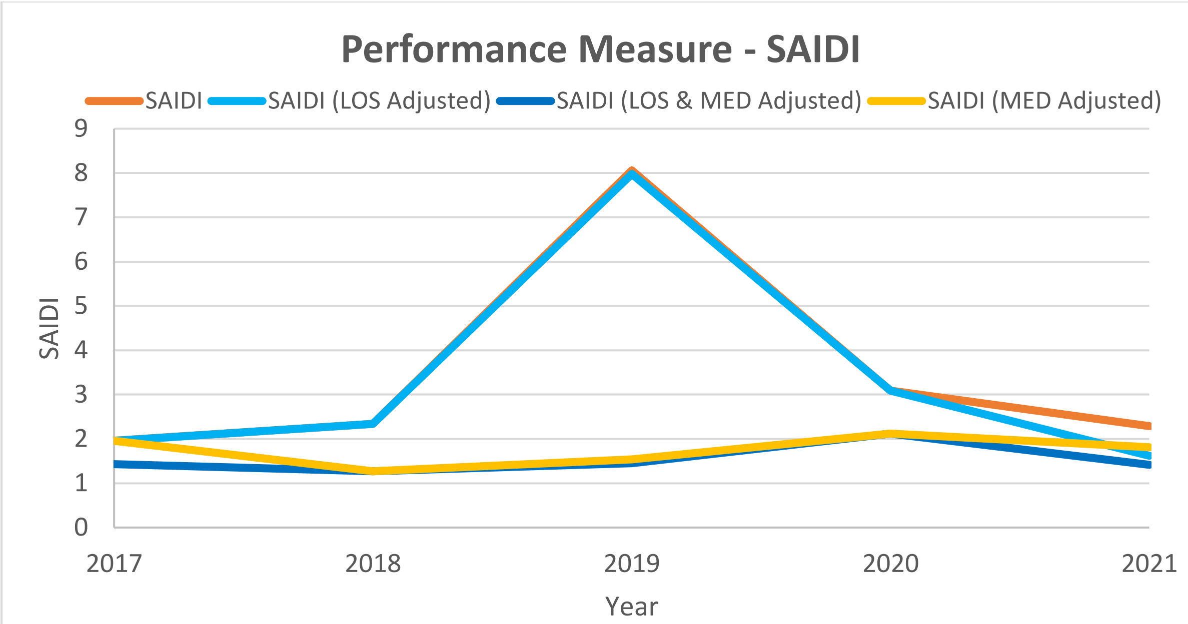


Figure 5.2-1: Performance Measure – SAIDI

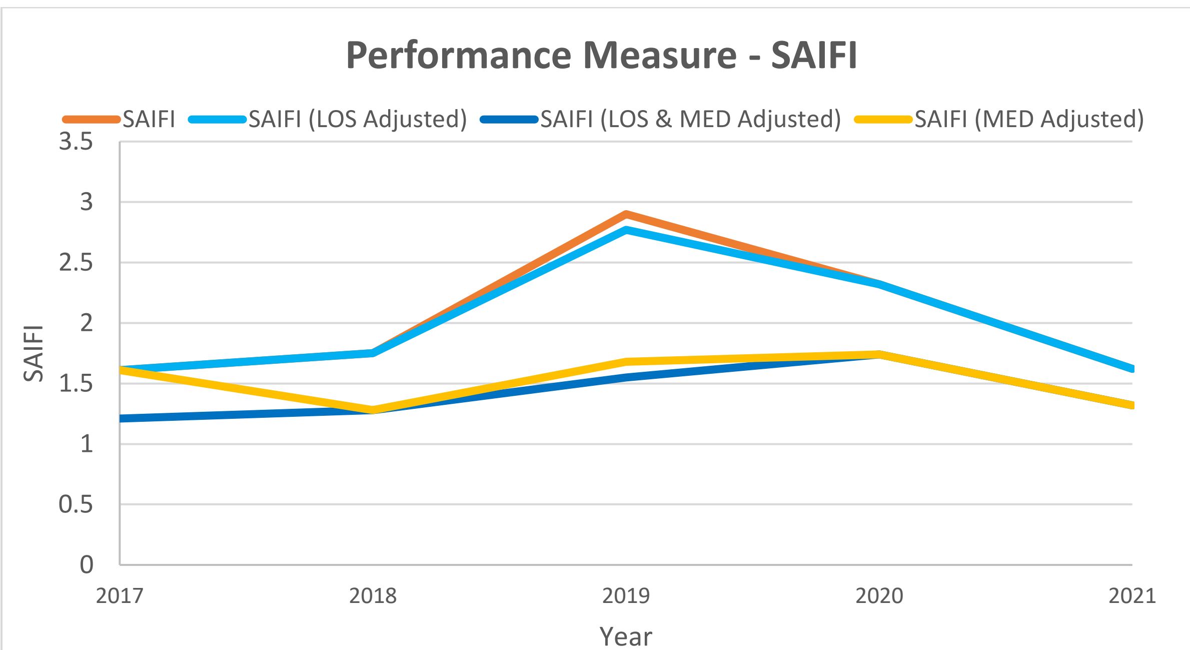


Figure 5.2-2: Performance Measure – SAIFI

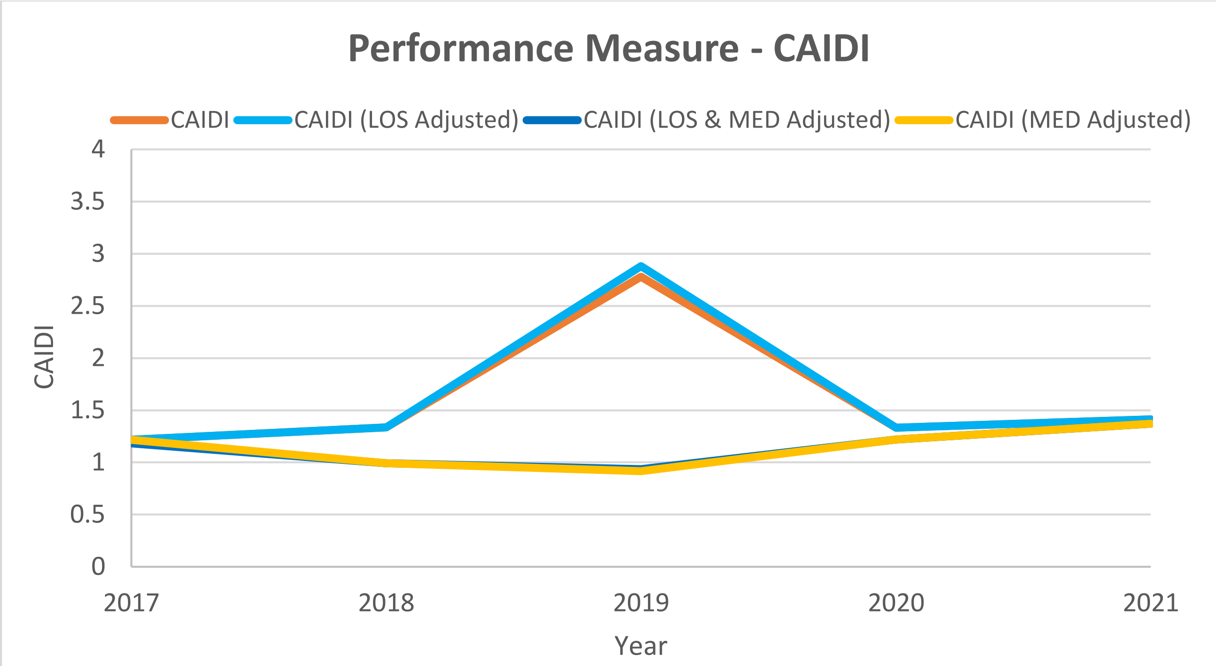


Figure 5. 2-3: Performance Measure – CAIDI

<u>Performance</u>

The significant spike in reliability performance observed in 2019 before adjusting for LOS and MED can be attributed to six MEDs caused by Adverse Weather and Foreign Interference, which are described in detail in Section 5.2.3.2.3 below.

Once adjusted for MED and LOS, a slightly worsening trend in both SAIDI and SAIFI can be observed between 2017 and 2020, which is followed by an improvement in performance in 2021. As noted in Section 5.2.3.1 above, the decrease in reliability performance over these years can be attributed to a combination of Defective Equipment, Adverse Weather and Foreign Interference. Excluding 2019, 2020 and 2021, PUC has historically met its targets for its reliability metrics, once adjusted for LOS and MED.

Going forward, aspects of the SSG Project, including the DA functionality and utilization of the outage management system (OMS) module, are expected to have a positive impact on reliability performance. Additional details are provided in Section 5.2.3.3 below.

5.2.3.2.3 Outage Details for Years 2017-2021

<u>Major Events</u>

The applicant should also provide a summary of Major Events that occurred since the last Cost of Service (COS) filing.

A "Major Event" is an event that is beyond the control of PUC. Because these events occur infrequently and unpredictably, these events are not considered when designing and operating the distribution system. The following tables provide a summary of PUC's Major Event Days (MEDs) over the historical period.

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

Year	# of MEDs	Cause of MEDs
2017	2	Lightning
2018	3	Adverse weather (two major storms) and foreign interference (one motor vehicle accident)
2019	6	Adverse weather and foreign interference
2020	1	Adverse weather
2021	1	Lightning

Table 5.2-10: List of MEDs over the Historical Period

Date	Customer Base Interrupted	Description
June 11, 2017	7,029	A severe thunderstorm warning was issued for Sault Ste. Marie at 1:30 pm. At approximately 5:00 pm, a lightning strike caused a power outage to 7,029 customers for approximately 1 hour.
August 2, 2017	6,135	A severe thunderstorm warning was issued for Sault Ste. Marie. At approximately 3:00 am, a lightning strike caused a power outage to 6,135 customers for approximately 2 hours.
September 21, 2018	6,569	At approximately 7:00 am, severe thunderstorms rolled through the Sault Ste. Marie area causing an adverse weather event that affected 6,569 for approximately 1.5 hours.
October 4, 2018	5,834	At approximately 12:30 am, severe thunderstorms rolled through the Sault Ste. Marie area causing an adverse weather event that affected 5,834 for approximately 5.5 hours.
October 26, 2018	3,296	At around 1:54 am, foreign interference caused a major event affecting 3,296 customers for 1.5 hours.
February 4, 2019	4,554	At approximately 1:54 pm, extreme winter weather came through the Sault Ste. Marie area causing an adverse weather event that affected 4,554 for approximately 3.2 hours.
February 8, 2019	7,302	At approximately 4:11 am, extreme winter weather came through the Sault Ste. Marie area causing an adverse weather event that affected 7,302 for approximately 1.5 hours.
March 15, 2019	4,079	On March 15, 2019, extreme winter weather caused high winds and freezing rain. This triggered an adverse weather major event affecting 4,079 customers for 1.8 hours.
September 5, 2019	1,864	At 4:19 pm, a Boom Truck collided with power lines in the east end of the city causing power to be lost to 1,864 for approximately 3 hours. This was defined as a major event under cause code 9 foreign interference.
November 27, 2019	5,712	At approximately 7:00 am, high winds and gusting snow knocked out power to 5,712 customers for approximately 4 hours.
December 30, 2019	21,913	On December 30, 2019, a major ice and windstorm caused a major event under cause code 6 – adverse weather. 21,913 customers were without power. 90% of those customers power was restored in 45 hours.
September 29, 2020	15,597	At 4:15 pm, Sault Ste Marie experienced heavy rain and moderate winds that contributed to the major event. 15,597 customers were without power for 2.3 hours.
August 29, 2021	10,255	On August 29, 2021, lightning caused a significant outage to 10,255 customers for approximately 2.5 hours.

Outages Experienced by Cause Codes

For each cause of interruption, a distributor should, for the last five historical years, report the following data:

- *Number of interruptions that occurred as a result of the cause of interruption*
- *Number of customer interruptions that occurred as a result of the cause of interruption*
- *Number of customer-hours of interruptions that occurred as a result of the cause of interruption*

Table 5.2-11 presents a summary of outages that have occurred within PUC's service territory under four different categorizations. The table values indicate no definitive trend with respect to outages within PUC's service territory, once excluding MED and LOS outages.

Table 5.2-11: Number of Outages (2017-2021)

Categorization	2017	2018	2019	2020	2021
All interruptions	470	352	566	487	444
All interruptions excluding LOS	470	352	564	487	444
All interruptions excluding MED	468	349	560	486	443
All interruption excluding MED and LOS	468	349	558	486	443

The root cause of power interruptions is monitored and analyzed by PUC. Each power outage that occurs on PUC's distribution system is recorded and an outage cause code is assigned. There are no targets for root cause of power interruptions, but it is monitored for investment planning purposes and to identify specific outage causes that need to be addressed to improve negative trending.

Table 5.2-12 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 impacts customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer fewer outages with longer duration thereby reducing the overall impact on production and business disruption. PUC continues to assess and execute capital and O&M projects to manage the number of outages experienced.

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

Cause Code	2017	2018	2019	2020	2021	Total Outages	Percent Share
0-Unknown/Other	11	29	19	16	123	198	9%
1-Scheduled Outage	195	154	184	157	109	799	35%
2-Loss of Supply	0	0	2	0	0	2	0%
3-Tree Contacts	43	14	20	49	35	161	7%
4-Lightning	4	1	8	0	5	18	1%
5-Defective Equipment	144	74	122	174	89	603	26%
6-Adverse Weather	38	41	164	32	24	299	13%
7-Adverse Environment	1	0	1	1	1	4	0%
8-Human Element	1	4	4	2	1	12	1%
9-Foreign Interference	31	32	36	55	56	210	9%
Total	**468**	**349**	**560**	**486**	**443**	**2,306**	**100%**

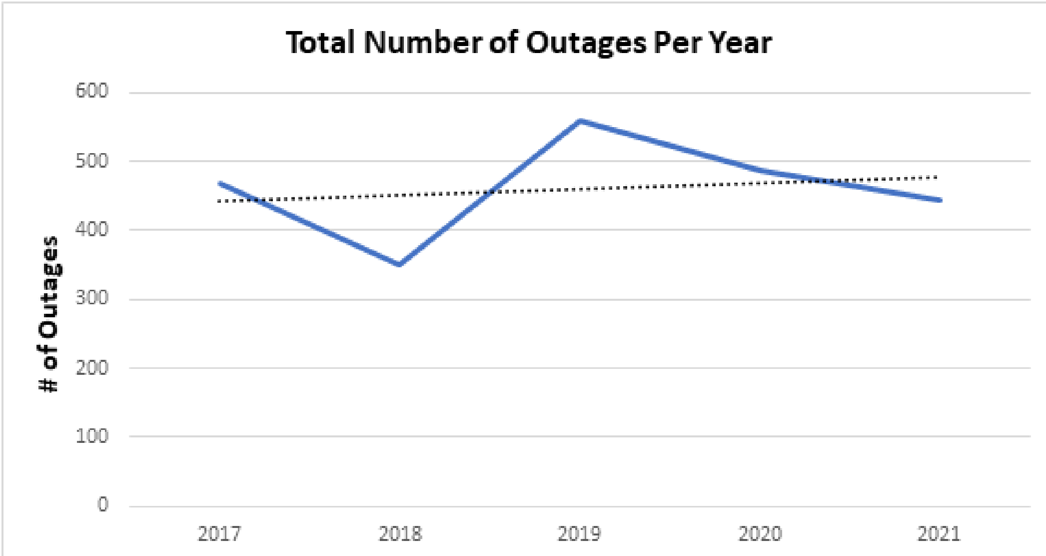


Figure 5.2-3: Total Number of Outages by Year

The total annual number of interruptions over the historical period varies from a low of 349 to a high of 560, with the overall trend increasing in the period. This represents an average of 0.956 to 1.534 interruptions per day.

A summary of the causes of outages within PUC's system is presented in the following graph along with the percentage of overall outage incidents attributable to each cause type.

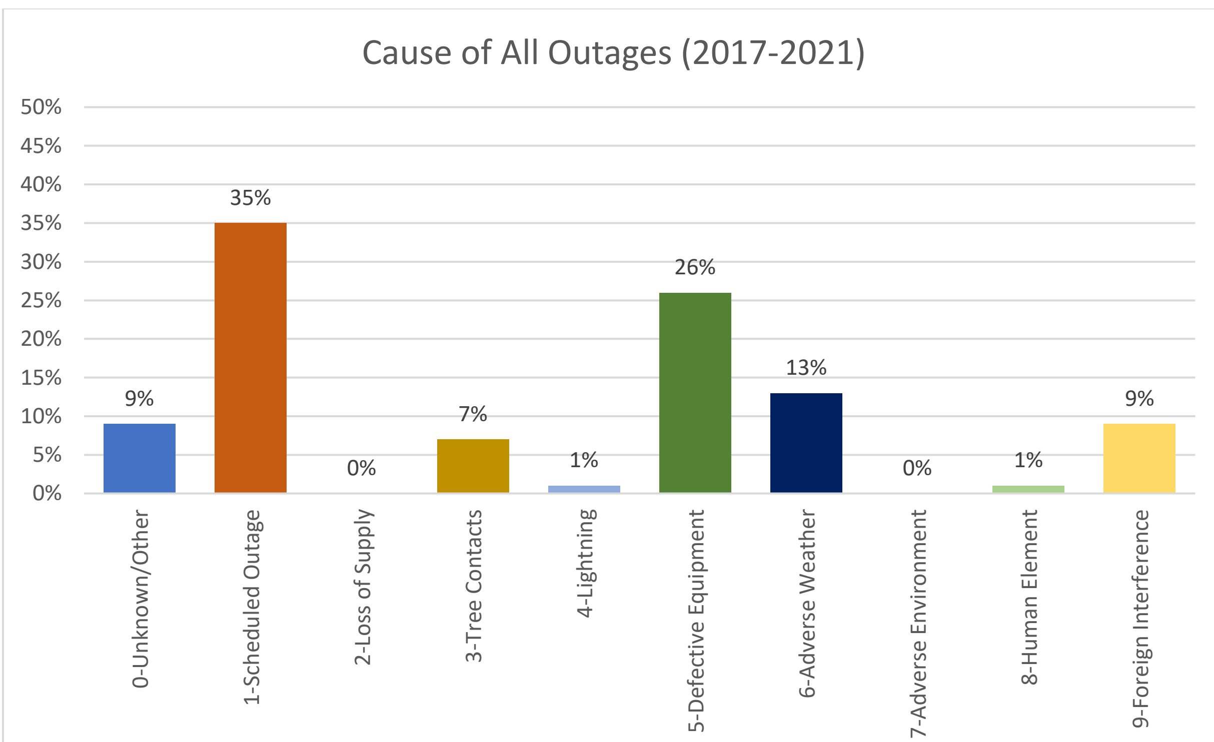


Figure 5.2-4: Percent of Outages by Cause Code

As illustrated in Figure 5.2-4 above, the top three contributors to the quantity of outages experienced over the historical period are Scheduled Outages, Defective Equipment and Adverse Weather.

At 35%, Scheduled Outages represents the largest cause for outages on PUC's distribution system over the last five years. Scheduled Outages are due to the disconnection of service for PUC to complete capital investments or to perform maintenance activities on assets that require them to be disconnected for employee safety. PUC aims to mitigate the impact of these outages through proactive planning and advanced notice to affected customers.

At 26%, Defective Equipment represents the next largest cause for outages on PUC's distribution system. Defective Equipment failures result from equipment failures due to condition deterioration, ageing effects or imminent failures detected from reoccurring maintenance programs. PUC has planned 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. PUC utilizes asset condition data from the recently completed ACA to assist in prioritizing investments in asset classes.

At 13%, Adverse Weather represents the third largest cause for outages. Adverse weather includes outages resulting from rain, ice storms, snow, winds, freezing rain, frost of other extreme weather conditions. These outages are outside of PUC's control, however PUC continues to invest in building more resilient infrastructure according to the more stringent design standards coming into effect as time goes on to help mitigate the impacts of adverse weather on the grid.

PUC closely monitors both the Defective Equipment and Adverse Weather measures to help gauge the appropriate degree of investment required in asset renewal and grid resilience.

<u>Customers Interrupted and Customers Hours Interrupted</u>

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 5.2-13: Customers Interrupted Numbers by Cause Codes – Excluding MEDs

Cause Code	2017	2018	2019	2020	2021	Total CI	Percent Share
0-Unknown/Other	4,162	3,045	1,689	3,636	7,768	20,300	7%
1-Scheduled Outage	1,856	3,838	2,728	2,453	1,872	12,747	5%
2-Loss of Supply	0	0	4,465	0	0	4,465	2%
3-Tree Contacts	9,695	1,355	2,231	9,672	6,218	29,171	11%
4-Lightning	1,277	48	6,815	0	561	8,701	3%
5-Defective Equipment	10,100	13,730	16,739	31,039	14,324	85,932	31%
6-Adverse Weather	5,915	4,561	25,437	10,822	5,255	51,990	19%
7-Adverse Environment	0	0	194	0	7	201	0%
8-Human Element	394	13,923	3,532	2,246	817	20,912	8%
9-Foreign Interference	7,466	2,721	12,002	8,448	7,960	38,597	14%
Total	**40,865**	**43,221**	**75,832**	**68,316**	**44,782**	**273,016**	**100%**

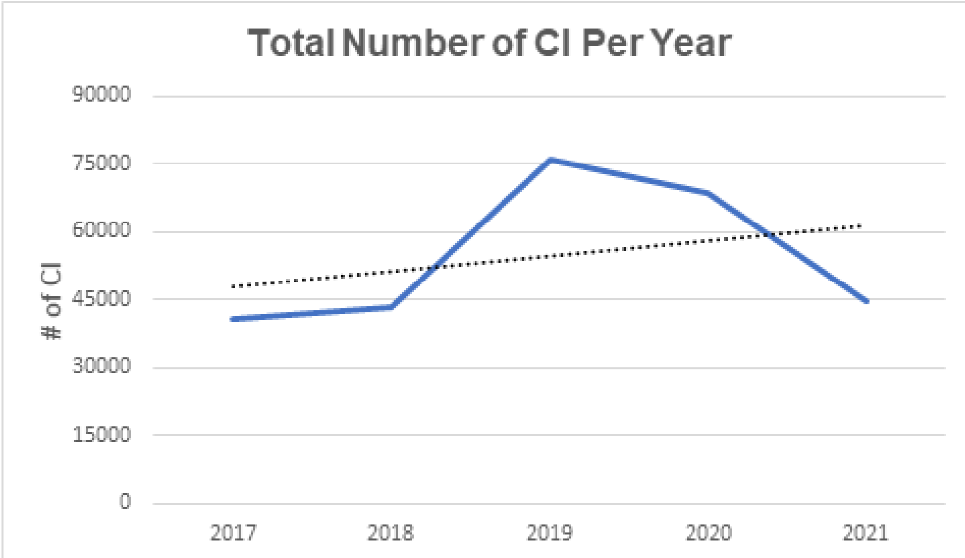


Figure 5.2-5: Total Number of Customers Interrupted by Year

Table 5.2-14: Customer Hours Interrupted Numbers by Cause Codes – Excluding MEDs

Cause Code	2017	2018	2019	2020	2021	Total CHI	Percent Share
0-Unknown/Other	5,593	3,715	2,061	1,315	10,183	22,866	8%
1-Scheduled Outage	2,946	6,311	6,695	4,245	3,311	23,507	8%
2-Loss of Supply	0	0	2,869	0	0	2,869	1%
3-Tree Contacts	12,032	1,561	3,765	10,295	9,196	36,849	13%
4-Lightning	3,733	64	5,891	0	919	10,607	4%
5-Defective Equipment	9,546	19,757	11,658	42,838	19,240	103,039	35%
6-Adverse Weather	6,210	5,628	8,523	13,462	11,189	45,012	15%
7-Adverse Environment	0	0	259	0	40	299	0%
8-Human Element	59	2,974	1,161	376	123	4,693	2%
9-Foreign Interference	7,990	2,892	8,681	14,826	7,286	41,676	14%
Total	**48,109**	**42,902**	**51,563**	**87,357**	**61,487**	**291,418**	**100%**

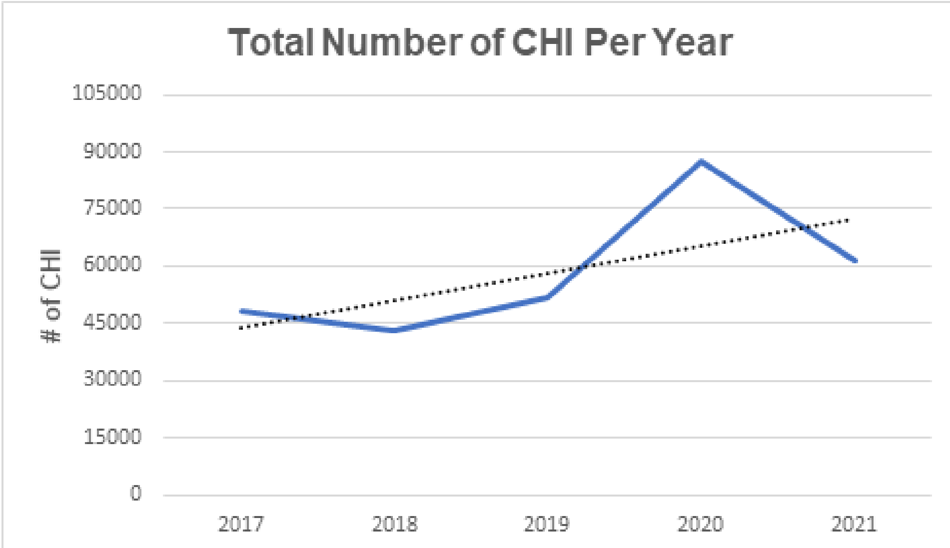


Figure 5.2-6: Total Number of Customers Hours Interrupted by Year

When analyzing CI and CHI, Defective Equipment and Adverse Weather remain within the top contributing causes, as seen in Table 5.2-13 and Table 5.2-14. However, Foreign Interference and Tree Contacts are also large contributors. Foreign Interference, which includes outages caused by animals, vehicles, dig-ins or other foreign objects are beyond the control of PUC however PUC does what it can to minimize these outages (e.g., installing animal guards). Tree contacts are interruptions caused by faults resulting from tree contact with energized circuits. Although tree contacts are generally outside of PUC's control, PUC will continue to implement its vegetation management program in order to mitigate the risk of outages caused by tree contacts.

PUC uses outage data to gauge the system reliability performance and maintain tight control over capital and maintenance spending. Within this DSP period, there are several ongoing and planned efforts to reduce the number of controllable outages and continue meeting the established reliability targets. These efforts include:

- Planned renewal of end-of-life assets such as poles and transformers
- Restricted conductor program to eliminate brittle, undersized coper conductor prone to failure
- Voltage conversion program to replace end of life 4.16 kV system with 12.47 kV
- Replacement of failing underground vaults and cable connections
- Replacement of end-of-life protection relays and station breakers
- Proactive vegetation management using a third-party company
- Ongoing inspection & maintenance of assets to identify and mitigate potential problems

5.2.3.3 SSG Project Benefits on Service Quality and Reliability Performance

On page 47 of PUC's resubmission of its ICM Application for the SSG Project (EB-2018-0170/EB-2020-0249) on October 28, 2020, PUC discussed the benefits the SSG Project will have on the four main performance outcomes of the regulatory scorecard (Customer Focus, Operational Effectiveness; Public Policy Responsiveness and Financial Performance). The following paragraphs describe how customers stand to benefit in each of those categories.

Customer Focus

Based on PUC's numerous customer engagements, customers' feedback has been for PUC to reduce cost, enhance reliability, and improve communication. Through the SSG Project, PUC will address most of the feedback. To begin with, customers will have neutral or reduced bills due to energy savings resulting from this project. Next, technologies such as the Advanced Distribution Management System (ADMS) and DA monitoring will help maintain and improve system reliability. Lastly, the OMS, which helps identify outages and provide immediate information on the system can be used to alert customers about outages and event response, which will improve PUC's customer communication and relationship.

Operational Effectiveness

One of the primary goals of the SSG project is to improve PUC's operational effectiveness with better planning, system monitoring, data management, and reporting. In addition, SSG Project also aims to reduce overall system losses with energy savings and demand reduction. New system modelling tools will allow for long term planning and system load forecast and management, helping manage asset utilization and extend asset life.

In terms of System Reliability metrics, the DA functionality of the SSG Project will help to automatically restore partial circuits which is expected to improve SAIDI and SAIFI going forward. The OMS will also help PUC manage and respond to outages in a timely manner by means of providing better data and information on the outage thereby allowing crews to be dispatched faster. However, the SSG Project impact on reliability is considered more of a positive trending variable than a hard target because the DA as applied at each outage event can be measured to calculate the difference in the new actual customer minutes of interruption as compared to what would have been the result to customers without the DA. That improvement in an annual cumulative value reflects the overall improvement in reliability to the system.

In terms of cost control, customers will receive dollar savings from consumption reductions, lower loss factor, and reduced peak demand (and resulting Retail Transmission Service Rate (RTSR) charges). Additionally, customers will receive all the benefits of the SSG Project while achieving a no net bill increase. However, when it comes to the measurements of cost control in the scorecard, it is important to note that these benefits will not be properly reflected in PUC's total cost per customer, total cost per km of line and ultimately its measure of efficiency. In 2023, PUC will have the Substation 16 ICM application[4], the SSG Project ICM application and its 2023 capital expenditures all part of its rate base. This will increase PUC's total costs to a projected total of $32,892,271, thus increasing the total cost per customer and total cost per km of line to $965 and $44,569, respectively. It is projected that PUC's predicted costs versus actual cost will increase the percentage difference to 14.46% in to 2023. A comparison of PUC's cost control metrics, including PUC's five-year historical performance and projections for 2022 and 2023, are presented in Table 5.2-15 below.

[4] The Substation 16 ICM project was completed in 2021, however the multi-year project cost of $6.02M currently remains in a regulatory account. OEB approval of the total project cost is required before the project can be added into rate base. Additional information can be found in Section 2.2.8 of Exhibit 2.

Table 5.2-15: Cost Control Performance

	2017	2018	2019	2020	2021	2022 Projection	2023 Projection
Total Costs	$22,600,176	$23,190,013	$23,450,122	$22,723,503	$23,585,229	$25,198,794	$32,892,271
Total Costs per Customer	$673	$690	$697	$673	$696	$742	$965
Total Cost per km of Line	$30,541	$31,338	$31,775	$30,791	$31,915	$34,145	$44,569
Predicted vs. Actual Costs Difference	11.24%	8.17%	5.50%	1.10%	1.77%	0.63%	14.46%
3 year moving average	13.8%	11.1%	8.3%	4.9%	2.8%	1.17%	5.62%
Efficiency Grouping	4	4	3	3	3	3	3

It remains to be determined what the exact consumption savings in (kWh) and resulting dollar amount will be for customers in a given year. However, the table below shows a sensitivity analysis of the consumption savings at 2%, 2.70% as shown in PUC's Argument in Chief from March 12, 2021 (EB-2019-0170/EB-2020-0249), and 4%. Applying theses savings to PUC's Total costs in the table above results in a revised total cost per customer, total cost per km of line and an updated predicted versus actual costs presented in Table 5.2-16 below.

Table 5.2-16: Impact of SSG Project on Cost Control Performance – Sensitivity Analysis

	2023 Projection (No savings applied)	2023 Projection (2% savings applied)	2023 Projection (2.7% savings applied)	2023 Projection (4% savings applied)
Savings ($)	$-	$1,465,714	$1,950,831	$2,851,764
Total Costs	$32,270,215	$31,426,557	$30,941,440	$30,040,507
Total Cost per Customer	$967	$922	$908	$881
Total Cost per km of Line	$44,569	$42,583	$41,926	$40,705
Predicted vs. Actual Costs Difference	14.46%	9.90%	8.35%	5.39%

<u>Public Policy Responsiveness</u>

Environmental, Social and Governance (ESG) and other Net-Zero Emissions initiatives across multiple industries has accelerated the desire for renewable and green technology. For example, Canada is currently working towards net-zero electricity by 2035[5], with the Government of Canada focusing on key areas like emerging technologies to reduce emissions within the electricity sector. The ADMS technology will be utilized to operate with increased system performance data and grid intelligence which will enable PUC to better manage and accommodate changing demands and emerging technologies, such as DER and electric vehicle requirements, in a modern grid system.

<u>Financial Performance</u>

[5] Canada launches consultations on a Clean Electricity Standard to achieve a net-zero emissions grid by 2035 - Canada.ca

With improved planning and operational effectiveness due to new modelling tools and technologies, PUC anticipates a positive long-term financial performance.

Initially, the SSG Project will increase PUC's debt-to-equity ratio over the OEB threshold of 60/40. However, given PUC's innovative approach to the project, the NRCan grant helps to improve the debt-to-equity ratio that would otherwise be significantly higher. Over time there is an improvement to the debt-to-equity ratio due to future capital projects from 2024-2027 requiring less borrowing.

The SSG Project will increase PUC's rate base significantly, thus increasing its ROE while still creating yearly savings to customers through VVO. As presented in the customer net benefit Table 5.3-29 below, the project is anticipated to save customers 2.7% in energy consumption, or $234,177 in 2023. These energy savings help customers to manage their bills better, which in turn should have longer-term impacts and savings to PUC through reduced bad debts and administration of the disconnection process.

5.2.3.4 Distributor Specific Reliability Targets

As established in the Report of the OEB: Electricity Distribution System Reliability Measures and Expectations, distributors' SAIDI and SAIFI performance is expected to meet the performance target set out in the Scorecard. A distributor who wishes to establish performance expectations based on something other than historical performance should provide evidence of its capital and operational plan and other factors that justify the reliability performance it plans to deliver. Distributors should also provide a summary of any feedback from their customers regarding the reliability of the distributor's system.

Distributors who wish to use SAIDI and SAIFI performance benchmarks that are different than the historical average must provide evidence to support the reasonableness of such benchmarks.

The fixed performance baseline targets for SAIDI and SAIFI over the historical period were set based on the average performance over the 2013-2017 period, excluding LOS and Major Events. This corresponded to a fixed target of 1.38 for SAIDI and 1.33 for SAIFI.

In addition to meeting the fixed performance baseline targets, SAIDI and SAIFI trending is done by comparing the fixed performance baseline targets against the most recent five-year rolling average (i.e., average of the most recent five-year performance, updated annually). This information is reported annually as part of the OEB Scorecards.

5.3 ASSET MANAGEMENT PROCESS

A distributor must use an asset management process to plan, prioritize, and optimize expenditures. The purpose of the information requirements set out in this section is to provide the OEB and stakeholders with an understanding of the distributor's asset management process, and the links between the process and the expenditure decisions that comprise the distributor's capital investment plan.

This section describes in detail PUC's asset management (AM) process and the direct links between the AM process and the expenditure decisions that comprise the capital investment plan covered by this DSP.

Key elements of the process that drive the composition of PUC's proposed capital investments are highlighted including data inputs, preliminary process steps and outputs, along with PUC's AM philosophy. The relationship between the RRF outcomes, corporate goals, AM Objectives, and the linkage to the selection and prioritization of PUC's planned capital investments is explained which control PUC's financial performance and planning.

The information generally used throughout the DSP is based on available information established at the given moment.

5.3.1 Planning Process

5.3.1.1 Overview

The distributor must provide an overview of its planning process that has informed the preparation of the distributor's five-year capital expenditure plan (a flowchart accompanied by explanatory text may be helpful).

PUC's AM process proactively identifies, manages, and mitigates risks within their electricity distribution system, thereby allowing PUC to achieve a desired level of service for their customer base at the best appropriate cost as accepted by their customers.

Integrated within PUC's AM process are Asset Management Objectives (AM Objectives) that are largely driven by a combination of PUC's corporate mission, vision, values and strategic goals (previously described in Section 5.2.1.1.2), and relevant legislative and regulatory obligations, including the OEB's RRF Performance Outcomes and requirements outlined in the DSC and the OEB Act.

PUC's AM Objectives form the high-level philosophy framework for its capital program. These objectives help to define the content of the programs and the major projects in the capital expenditure plan to be able to sustain PUC's electrical distribution system. The objectives guide PUC 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 qualitatively integrated into PUC's capital investment process to prioritize investments for several years including the bridge and Test Year.

Table 5.3-1: AM Objectives, Measures, Targets, and Relationship to the RRF & Corporate Goals

RRF Outcomes	Strategic Corporate Goals	AM Objectives	AM Objective Measure	AM Objective Target
Operational Effectiveness	Safety	Manage and operate the system in a safe manner and in accordance with good utility practice.	1. Lost/non-lost time 2. ESA Non-Compliance	1. WSIB rate class 10-year benchmarks 2. Zero (Max 1 NI)
	Reliability	Monitor and continue to provide high reliability performance of the distribution system.	1. SAIDI 2. SAIFI	1. SAIDI within range of past 5-year performance 2. SAIFI within range of past 5-year performance
Customer Focus	Customer Focus	Meeting customers' needs and expectations including connecting renewable generation, ensuring quality of power, reliability of continued uninterrupted service, and availability to address concerns.	1. Customer Survey 2. New connections connected within set timescales	1. Customer survey results => previous year results 2. >90%
Financial Performance	Financial Performance	Manage the distribution system through proactively maintaining and or replacing assets in a financially prudent way that maximizes rate payers value.	1. Investment Spending 2. Investment Scheduling	1. Group 3 (within +/-10% of predicted costs) 2. >90% annual projects/ programs completed on time
Public Policy Responsiveness	Public Policy Responsiveness	Ensure environmental risks are managed. Facilitate smart grid development and new renewable connections.	1. Facilitation of smart grid and REG connections	1. 100% compliance when a request is made by a customer

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. 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, investments not made on time when warranted by system needs raise the risk of performance targets not being achieved and contribute to sub-optimal operation. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into 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.

5.3.1.2 Important Changes to Asset Management Process since last DSP Filing

A distributor should provide a summary of any important changes to the distributor's asset management process (e.g., enhanced asset data quality or scope, improved analytic tools, process refinements, etc.) since the last DSP filing.

PUC's AM processes have not had any material changes compared to the previous DSP filings with the OEB. All reporting, processes, practices, and inputs remain largely intact and the same with only small continuous improvement and evolutionary changes occurring since the previous filing.

5.3.1.3 Process

A distributor should provide the processes used to identify, select, prioritize (including reprioritizing investments over the five-year term), and pace the execution of investments over the term of the DSP. A distributor should be able to demonstrate that it has considered the correlation between its capital plan and customers' needs. A distributor should also demonstrate that is has considered the potential risks of proceeding/not proceeding with individual capital expenditures (e.g., the risk/benefit of a reactive service transformer replacement program instead of proactively replacing service transformers).

A distributor should consider, where applicable, assessing the use of non-distribution alternatives, cost-effective implementation of distribution improvements affecting reliability and meeting customer needs at acceptable costs to customers, other innovative technologies, and consideration of distribution rate funded Conservation and Demand Management (CDM) programs.

2021 CDM Guidelines: Distributors are required to make reasonable efforts to incorporate consideration of CDM activities into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure. A distributor's distribution system plan should describe how it has taken CDM into consideration in its planning process.

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

PUC's AM process is shown in Figure 5.3-1. The AM process is established in a way to coordinate activities to ensure the assets are optimally achieving the company's corporate and AM Objectives. PUC's AM process is an iterative process that is regularly updated with the latest set of data and information to ensure that PUC are initiating the capital projects and maintenance at the right time. As well as using this process to develop its original five-year DSP capital plan, PUC also use it annually to update its budget and plan for the following year.

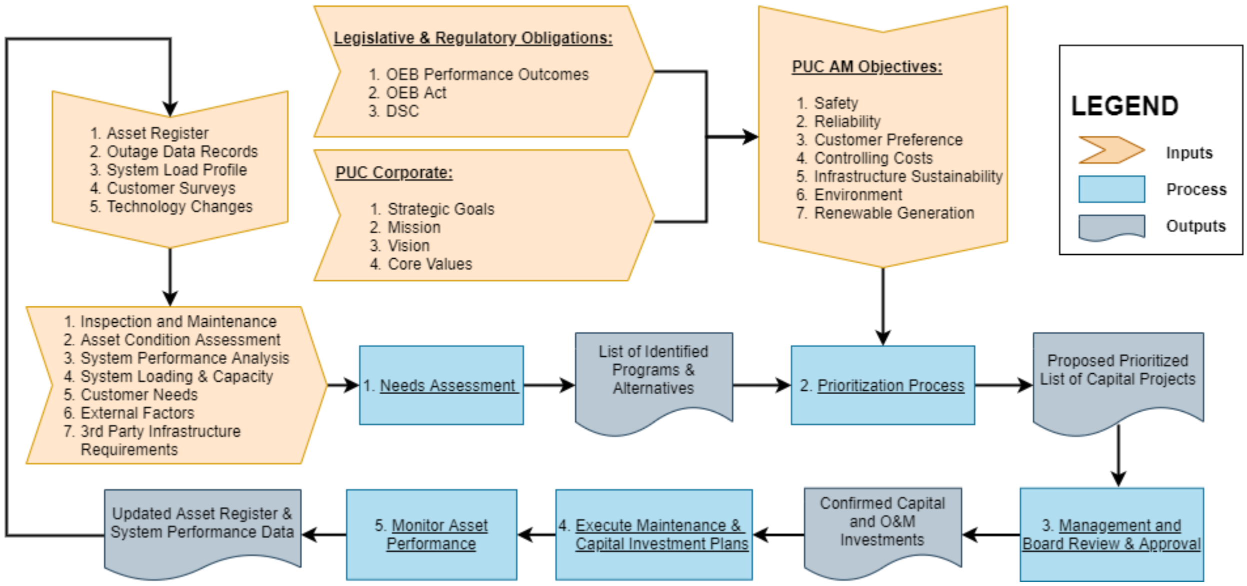


Figure 5.3-1: PUC's AM Process

PUC uses the input data and information to enable it to determine its operating and capital expenditure plans. As illustrated in Figure 5.3-1, this is done in a multistage process with various outputs at each stage.

Step 1 - Needs Assessment

Firstly, using input data such as asset condition assessment, system performance, customer engagement results, a need assessment is performed to identify the needs required under each of the four investment categories:

- **System Access:** System access needs are identified through contact with customers wishing to connect new services, service upgrades, requests from municipal landowners to relocate assets to accommodate road reconstruction, requests from developers to build new subdivisions or requests for services from joint use communication companies. This category also considers investments needed to comply with the OEB directive to equip all general service customers with >50kW and <500kW demand with Metering Inside the Settlement Timeframe (MIST) meters. System access investments are non-discretionary in nature and are budgeted and scheduled to meet the timing needs of the external proponents.
- **System Renewal:** System renewal needs are identified using a combination of asset and system related data including asset condition and demographic information, inspection and maintenance records, outage data and system performance. Customer input is also considered. System renewal investments are discretionary in nature.
- **System Service:** System service needs are identified by analyzing the ability of the distribution grid to supply existing and anticipated load and generation customers. The regional planning process, customer input and technological advancements are also considered. In addition, further needs are identified by reviewing whether investments are required to address system operational objectives (e.g., safety, reliability, power quality etc.). System service investments are discretionary in nature.
- **General Plant:** General plant needs are identified and assessed using a combination of inspections, policies, and expert knowledge. Investments into building repairs are based on identified deficiencies through inspections of building interior and exterior, doors and fixtures, HVAC, parking lots, security system and building mechanical systems. Since PUC leases its

motor vehicle assets rather than owning them, PUC's fleet-related investment needs are relatively small. General plant investments are discretionary in nature.

This step allows PUC to identify high-level projects and programs that PUC could undertake to address the needs required over a five-year period based on the best available information for each year. As part of this, an evaluation of the different options to address the need is also performed. This includes looking at options of full replacement, refurbishments or do nothing, investigating pacing requirements, and resource availability. At this stage, PUC also considers the applicability of CDM to determine whether CDM is a feasible option to meet the identified system need. This allows PUC to streamline the programs it will undertake with a recommended list of programs and alternatives.

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

Step 2 – Prioritization Process

Following the identification of recommended programs and alternatives to address the identified needs, a prioritization process is undertaken. At this stage, further inputs are considered, such as PUC AM Objectives and the OEB RRF Performance Outcomes. This information along with the programs identified are used to identify specific projects within the programs and identify a prioritized list of projects.

Non-discretionary projects are automatically selected, receive highest priority, and are prioritized based on externally driven schedules and needs. Most system access projects fall into this category and may involve multi-year investments to meet proponent needs. For system access needs, project prioritization is based on the expected date when all service requirements are fulfilled by the customer and consideration of the customer's schedule for implementation, as identified through regular contact between parties.

The renewal of assets in a reactive mode (e.g., replacing an asset that has failed in service in order to restore power), and the replacement of assets to comply with regulations (e.g., replacing transformers with PCB >50ppm) also receives highest priority because their implementation is mandated in order for PUC to fulfil its regulatory obligations to supply electricity to all customers connected to the grid.

Discretionary projects are selected and prioritized based on value and risk assessments for each project. Most system renewal, system service, and general plant projects fall into this category. Discretionary projects under these categories are ranked by applying a set of refinement criteria. The refinement criteria and relative rankings used in prioritizing investments is indicated in Table 5.3-2.

Table 5.3-2: Prioritization Criteria & Weights

Criteria	Description	Weight
Public Safety Impact	Safety risks and consequences of equipment failure	40%
Outage Customer Impact	Quantity of customers affected and duration of outage	10%
Customer Value for Dollars Spent	Quantity of customers affected as a function of total project cost	15%
System Service improvements	Projects exhibit value in supporting the OEB System Service category as a secondary driver to System Renewal e.g.: station upgrades will support the	10%

Criteria	Description	Weight
	connection of REG through new protective equipment upgrades	
Project Interdependence	Projects that, if not completed, would negatively impact the ability to complete future planned projects	25%

Each year, PUC reassesses its capital plan and makes adjustment to the prioritization of projects as new information is received. For example, this could include deprioritizing an investment in one category to be able to deliver a more urgent project in another. In addition, PUC considers the pacing of investments within its five-year DSP term. This included considering if an investment needs to be carried out now or if it can be delayed and delivered later in the period. Factors such as resources, asset condition, risk, other associated projects are taken into consideration as part of its pacing and prioritization process. The completed prioritization matrix for PUC's Test Year projects over the materiality threshold is provided in Section 5.4.2.1.

Step 3 – Management and Board Review & Approval

In the next step, PUC's list of prioritized projects is reviewed and approved by the PUC management and Board. As part of this process, any final revisions are made as necessary.

Once PUC Management and Board approve the budget, the budget amounts do not change but rather provide a plan against which actual results may be evaluated. In addition to the capital needs of the distribution system, PUC plans for the required maintenance of its assets considering both performance and safety.

Step 4 – Execute Maintenance & Capital Investment Plans

Once the projects and associated operating and capital spend has been approved, the projects are monitored from initiation to execution. Monitoring includes active project management by the Engineering Department with scope, cost and timelines being continuously monitored for each project. Additionally, at a more macro level, quarterly reporting and review of the overall capital plan is undertaken to ensure variances, scope creep and delays are maintained to minimums.

Step 5 – Monitor Asset Performance

Once the projects are complete the asset are monitored on their performance and updated information is fed back into the asset registry.

5.3.1.4 Data

A distributor should identify, describe, and provide a summary of the data used in the processes above to identify, select, prioritize, and pace the execution of investments over the term of the DSP (e.g., asset condition by major asset type and reliability information).

PUC uses several datasets and inputs to assess the status of its distribution system assets and to assist in determining the capital and operational investments to be made in the system. This ranges from asset condition assessment, customer engagement, and inspection and maintenance results to what its AM Objectives are and how they link to the OEB's performance outcomes and any external factors. Some of the key elements are explained in further detail below.

Asset Register

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

Table 5.3-3: Information Comprising PUC's Asset Register

Asset Register Component	Owner/Location	Asset Information	Data Format
GIS	Engineering	> Pole location and age > Circuit conductor size, voltage, and phase(s) > Overhead switch, transformer, switchgear location and nomenclature	Electronic data
ACA Report	Engineering	> Asset condition assessment	Electronic data (spreadsheets, databases)
Outage History	Stations/Lines	>major equipment (station transformers, switchgear, protection system) >minor equipment, linear assets (distribution transformers, cables, disconnects)	work/enterprise management software, electronic databases
Maintenance Records	Stations/Lines	>major equipment (station transformers, switchgear, protection system) >minor equipment, linear assets (distribution transformers, cables, disconnects)	work/enterprise management software, electronic databases
Inspection Records	Stations/Lines	>major equipment (station transformers, switchgear, protection system) >minor equipment, linear assets (poles, distribution transformers, cables, disconnects, padmount switchgear, vaults)	work/enterprise management software, electronic databases
Asset Utilization Records	Stations	Major asset utilization, circuit loading	SCADA historian
General Plant Records	Engineering	All assets; drawings, plans, specifications, manuals, coordination studies, load studies.	Various electronic and legacy paper formats

Customer Survey Results & Needs

PUC focuses on providing reliable, efficient, and safe electricity to its customers. As part of the investment planning process, PUC conducts customer consultations to gather customers' opinions on its services and to ensure that the customers' needs and preferences are taken into consideration during the development of long-term plans. PUC has conducted both formal and informal community engagement activities with its customers over the last five years. Customer needs also address requirement for new customer connections and/ or modification to existing customer connections. Further information on PUC's customer engagement can be found in Section 5.2.2.1.

Technology Changes

PUC monitors innovation and development within the electrical/utility sector in order to stay up to date with current technology. Technological advances, such as automation, technology awareness, electric vehicle penetration, and battery storage, are considered as part of PUC's planning process, and where benefits of outweigh the costs, advanced technologies may be incorporated during implementation of asset renewal projects, to meet the current and future needs of the customers, to improve operating efficiency and to support the integration of renewables and smart grid technologies.

Inspection & Maintenance

PUC maintains a full schedule of distribution asset inspection and maintenance programs operating on a three-year rotation as required by the OEB's DSC. Inspection, maintenance, and operational data are collected and stored which is used to support PUC'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 allow a continual update of the asset database. The programs allow for assets to be inspected and assessed for any necessary actions that need to be taken promptly in a proactive approach. PUC's inspection and maintenance programs are audited every year as required by Ontario Regulation 22/04. Further information on PUC's maintenance and inspection practices can be found in Section 5.3.3.

Asset Condition Assessment

An ACA was undertaken in 2021 to assess the condition of the system and to have empirical data on which to base the revised project prioritization. The ACA involves the interpretation of condition and performance data of key assets to assess the overall condition of the asset. Essentially, 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 the ACA results can be found in Section 5.3.2.2.2, and the full ACA Report is included in Appendix H.

In addition to the ACA data, PUC intends to continue using the information from its ongoing proactive inspection and maintenance programs to optimize spending, with priorities considered in the scheduling. Under the proposed capital planning model, decisions to repair, refurbish or replace existing assets continues to be based on experienced judgment and knowledge of staff augmented with improved access to electronic records and structured evaluation processes.

Outage Data Records & System Performance Analysis

PUC places a high level of importance on ensuring distribution system reliability meets the expectations of its customers. PUC strives to continually improve its processes for collecting, measuring, analyzing, and utilizing outage information within its AM process to effectively manage distribution system reliability in its service territories.

PUC uses historical outage data records to gauge the system reliability performance and maintain tight control over capital and maintenance spending. Outage causes are tracked and analyzed by outage cause codes. This allows PUC to identify specific trends in causes of outages and allows for this information to feed into its prioritization and evaluation process when developing its capital and maintenance investment plans. The system performance analysis is ultimately used to inform PUC's AM process in developing the O&M programs and capital expenditure plan for each year. Additional information on PUC's reliability performance and outage data records are presented in Sections 5.2.3.2.2 and 5.2.3.2.3.

System Loading & 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. Further information can be found in Section 5.3.2.2.1.

External Drivers

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

- Political – governments have their directions and strategies that PUC needs to be mindful of and to be in alignment with their plans.
- Economic – economic growth and decline within PUC's service area as well as the shift of business operations within residential units.
- Social – changes in the environment that illustrate customer needs and wants.
- Technological – innovation and development within the electrical/utility sector which includes automation, technology awareness, electric vehicle penetration, battery storage and new services.
- Environmental – ecological and environmental aspects that can affect PUC's operations or demand which includes 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.

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

Third Party Infrastructure Requirements

PUC has an obligation, as per the DSC regulation, to address investments in third party infrastructure, which can include city-driven projects, new subdivision developments, joint use investments or customer connections. Any requirements by the city or other third parties to develop or modify the system are considered.

PUC regularly interacts with the City of Sault Ste. Marie and other municipal stakeholders such as developers and local utilities (water, gas, oil), to review budgets and work plans for the coming year and the next five years. Participating in these consultations allows PUC to learn about and understand upcoming projects in the community. Any requirements obtained from the municipality, developers and/or other utilities to develop or modify the system is considered and used as an input to identify investment level requirements in the system access category proposed in this DSP. Additional information on these consultations can be found in Section 5.2.2.2.

Legislative & Regulatory Obligations

PUC's AM process is also informed by several legislative and regulatory obligations including the OEB performance outcomes, the OEB Act and the DSC.

Corporate objectives

PUC is driven by its corporate vision, mission, and values. Together, they provide the basis to deliver on targeted strategic goals and performance objectives. PUC's mission, vision, values, and corporate strategic goals are detailed in Section 5.2.1.1.2.

AM Objectives

PUC's AM Objectives, as outlined previously in Section 5.3.1.1, are another key input into PUC'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 PUC's electrical distribution system. The objectives guide PUC 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 qualitatively integrated into PUC's capital investment process to prioritize investments for several years including the Test Year.

5.3.2 Overview of Assets Managed

Assessment of DSPs requires a comprehensive understanding of all aspects of the assets managed by a distributor. Distributors may vary in terms of the level of detail that it chooses to record for its distribution assets but the expectation is that in assessing the condition of major assets (e.g., station transformers and poles), solely using asset age is not sufficient.

This section presents a description of PUC' service area, a summary of the system configuration, asset condition, and PUC's system utilization relative to planning criteria.

5.3.2.1 Description of Service Area

A distributor should provide an overview of its distribution service area (e.g., system configuration; urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for supporting its capital expenditures over the forecast period.

5.3.2.1.1 Overview of Service Area

PUC's service territory as shown previously in Figure 5.2-1 includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. Its service territory covers a total service area of approximately 342 square kilometers, including a rural service area 284 square kilometres and an urban service area of 58 square kilometres. The combined population served is approximately 75,300.

5.3.2.1.2 Customers Served

PUC's customers are divided into three categories - residential, general service less than 50 kW, and general service greater or equal to 50 kW. The historical breakdown of customers served, as shown in Table 5.3-4, illustrates a slightly increasing trend in PUC's total customer base over the historical period.

Table 5.3-4: Changing Trends in PUC's Customer Base

Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2021	30,134	3,423	308	33,865
2020	30,026	3,355	370	33,751
2019	29,897	3,388	362	33,647
2018	29,837	3,414	362	33,613
2017	29,803	3,414	362	33,579

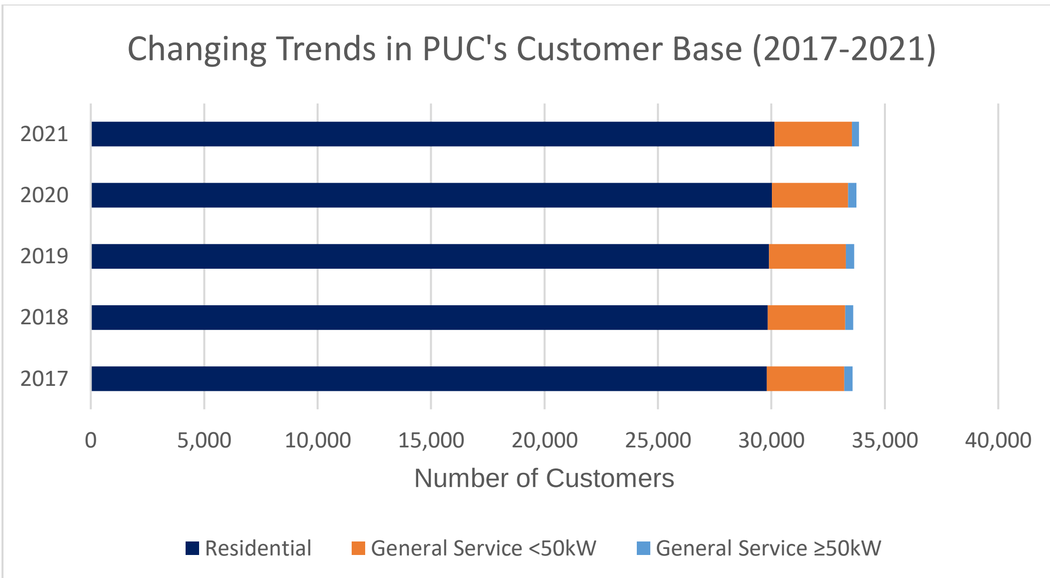


Figure 5.3-2: Change in Customer Base by Category over Historical Period

5.3.2.1.3 System Demand & Efficiency

Table 5.3-5 shows the annual season and average peak demand (kW) for PUC's distribution system.

Table 5.3-5: Peak System Demand Statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2021	111,371	90,881	92,284
2020	112,835	90,164	93,568
2019	132,818	84,220	97,163
2018	128,538	91,500	97,157
2017	125,683	90,753	96,500

Historically, electricity has been used for space heating in this region and therefore load on the electricity distribution grid peaks during the winter. For example, during the period from 2017 to 2021, the average winter peak load was approximately 37% higher than the average summer peak load. Historical shifting of space heating from electricity to natural gas, combined with the multiple energy

CDM initiatives implemented by residential and general service customers and expansion of natural gas distribution network in the region, has resulted in a modest but steady decline in the peak demand on the electrical grid. This trend is expected to continue until such time that incentivization to transition to a low carbon emissions-based economy starts to gain momentum with consumers.

Table 5.3-6 indicates the efficiency of kilowatt hours (kWh) purchased by PUC and delivered. Losses as a percentage of purchased energy has remained under 5% over the historical period except for 2018, and a slight improvement can be observed over the last four historical years (i.e., from 2018 to 2021).

Table 5.3-6: Efficiency of kWh Purchased by PUC

Annual Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2021	604,318,512	628,757,114	4.04%
2020	613,632,199	640,745,749	4.23%
2019	631,945,814	660,423,172	4.51%
2018	633,697,927	666,736,298	5.21%
2017	622,542,513	652,970,471	4.89%

The SSG Project will have a positive impact on efficiency through the Volt/VAR Optimization (VVO) systems. With the reduced energy utilized by customers through the VVO systems, a reduction in energy loss via the delivery of that energy across the distribution system of wires and transformation will also be achieved. Both the reduced customer energy (kWh delivered) and reduced system losses will be reflected in lower purchase power requirements.

5.3.2.1.4 Summary of System Configuration

PUC operates a system made up of 15.5 km of overhead 115 kV transmission, 99 km 34.5 kV subtransmission, and 623 km of distribution lines and cables (12.47 kV and below). PUC also owns and operates assets at 2 Transformer Stations (TS-1 and TS-2) and 14 distribution stations (DS).

Transformer Stations TS-1 and TS-2 step down power received from the transmitter at 115 kV to 34.5 kV. The 34.5 kV feeders supply 12 distribution stations, which step down power from 34.5 kV to 12.5 kV. There are also two additional distribution stations; one of which steps down from 34.5 kV to 4.2 kV, the second steps down from 34.5 kV to both 12.5 kV and 4.2 kV. The remaining two 4.2 kV distribution stations are planned to be retired from service, upon completion of the distribution voltage conversion program, during the next five years. Figure 5.3-3 below shows the geographic locations of transformer stations and distribution stations, within the PUC's service territory.

Figure 5.3-3: Distribution Station Locations

Table 5.3-7 shows the power transformer ratings and number of 34.5 kV feeders at each of the 115/34.5 kV transformer stations.

Table 5.3-7: 115/34.5 kV Substation Ratings

Transformer Station	Capacity	Number of 34.5 kV Feeders
TS-1	4x30 MVA	5
TS-2	4x30 MVA	5

In addition to the outgoing feeders, TS-1 also supplies Substation 19, which is located at the same site as TS-1. Both transformer stations are also equipped with power factor correction shunt capacitors. TS-1 employs shunt capacitors of 20 MVAR rating as well as a recently installed IESO controlled 7MW/+/-7MVAr/7MWh energy storage facility to provide dynamic Volt/VAR control. TS-2 employs shunt capacitors of 40 MVAR rating.

The tables below show the power transformer ratings and number of feeders at each of the distribution stations.

Table 5.3-8: 12 kV Distribution Station Ratings

12 kV Distribution Stations	Capacity	Number of 12.5 kV Feeders
DS-1	2x10 MVA	4
DS-2	2x10 MVA	4
DS-4	1x10 MVA	2
DS-10	2x10/13.3 MVA	4
DS-11	2x10 MVA	4
DS-12	2x10 MVA	4
DS-13	2x10 MVA	4
DS-15	2x10 MVA	4
DS-18	2X7.5 MVA	4

12 kV Distribution Stations	Capacity	Number of 12.5 kV Feeders
DS-19	2x10 MVA	4
DS-20	2x10 MVA	4
DS-21	2x10 MVA	4

Table 5.3-9: 4.2 kV Station Ratings

4.2 kV Distribution Stations	Capacity	Number of 4.2 kV Feeders
DS-4	1x10 MVA	2
DS-5	2x5 MVA	2

Major assets employed on the overhead and underground distribution network are summarized in Table 5.3-10. As indicated, the power supply network employs overhead lines operating at 115 kV, 34.5 kV, 12.5 kV, 7.2 kV, 4.2 kV and 2.4 kV as well as low voltage (LV), i.e., less than 750V, and it employs insulated cable circuits installed in duct and direct buried configurations, operating at 34.5kV, 12.5 kV, 7.2 kV, 4.2 kV and 2.4 kV.

Table 5.3-10: PUC's Distribution Assets (as of May, 2022)

Asset	Quantity	Units
3-Phase 115 kV Overhead lines	15,500	m
3-Phase 34.5 kV Overhead lines	74,245	m
3-Phase 12.5 kV Overhead lines	280,781	m
3-Phase 4.2 kV Overhead lines	14,185	m
1-Phase 7.2 kV Overhead lines	220,502	m
1-Phase 2.4 kV Overhead lines	7,243	m
Number of Poles on OH lines	18,125[1]	#
34.5 kV, 3-ph, UG, Cable circuits	24,524	m
12.5 kV, 3-ph, UG, Cable circuits	49,081	m
7.2 kV, 1-ph, UG, Cable circuits	48,323	m
4.2 kV, 3-ph, UG, Cable circuits	658	m
2.4 kV, 1-ph, UG, Cable circuits	0	m
Number of 1-ph pole mounted transformers	4,785	#
Number of 3-ph pole mounted transformers	29	#
Number of 3-ph pad mounted transformers	527	#
Number of 1-ph pad mounted transformers	415	#
Number of submersible transformers	466	#
Number of pad-mounted switchgear	25	#
Number of K-bar Units	131	#
Number of concrete structures	1,041	#

[1] Quantity of poles includes all poles PUC is attached to including communication owned poles, private poles, etc. Breakdown is as follows PUC Owned = 12,765, Other = 5,360

Table 5.3-11, Table 5.3-12 and Table 5.3-13 provide information on the number of feeders that are installed in overhead (OH) or underground (UG) or mixed OH/UG configurations at PUC's transformer and distribution stations.

Table 5.3-11: Number of 34.5 kV Feeders Installed in OH or UG Configurations

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
TS-1	5	5	0	0
TS-2	5	2	0	3

Table 5.3-12: Number of 12.5 kV Feeders Installed in OH or UG Configurations

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
DS-1	4	1	1	2
DS-2	4	2	1	1
DS-4	2	2	0	0
DS-10	4	4	0	0
DS-11	4	3	0	1
DS-12	4	1	1	2
DS-13	4	3	0	1
DS-15	4	2	1	1
DS-16	4	4	0	0
DS-18	4	1	0	3
DS-19	4	2	0	2
DS-20	4	2	0	2
DS-21	4	0	0	4

Table 5.3-13: Number of 4.2 kV Feeders Installed in OH or UG Configurations

Source Station	Total Number of Feeders	Number of OH Feeders	Number of UG Feeders	Number of Mixed OH/UG Feeders
DS-4	2	1	0	1
DS-5	2	2	0	0

5.3.2.1.5 Climate

The climate is typical of most towns in Northern Ontario and reaches temperature extremes of -40˚C during winter and +40˚C in summer. The normal monthly temperatures vary from -15˚C during winter and +25˚C in summer, with approximately ten days of precipitation in a month. Both overhead and underground distribution systems are employed in PUC's service territory. The presence of a number of different soil types, the Canadian Shield, numerous clays, and muskeg often make excavation activities a challenge, particularly for installation of underground distribution systems. The region is vulnerable to commonly occurring strong wind storms, lake-effect snow and ice loading from Lake Superior, which poses a challenge to overhead lines. PUC's entire service territory is located within the CSA heavy loading area as described in CSA 22.3 No. 1-15 Overhead Systems. Accordingly, the corresponding CSA referenced heavy loading conditions of radial thickness of ice; horizontal wind loading and temperature are accounted for in line designs.

5.3.2.1.6 Economic Growth

Historically, the local economy in PUC's service territory has been dominated by steelmaking. This industry has not experienced growth over the recent past and therefore, there hasn't been a significant contributor to growth in the region's population. This trend is expected to continue during the next five-year period, covered by this DSP.

During recent years, the community has invested a significant amount of effort to diversify the local economy and these diversification efforts have resulted in development and growth of services associated with call centers and data hosting and warehousing. There has been significant effort to grow the tourism industry, supported by a major Casino as a draw in the downtown. The corporate head office of Ontario Lottery and Gaming Corporation (OLG) is also located in Sault Ste. Marie and Sault Ste. Marie has become a regional hub to provide services for the surrounding rural communities. Availability of reliable electricity supply at affordable prices is an essential ingredient, needed for the region's diversification efforts to succeed.

According to Statistics Canada census data, the City of Sault Ste. Marie's has experienced about a 1.8% decline in population between 2016 and 2021. The pace of economic growth is not expected to change during the next five-year period, covered by the DSP.

5.3.2.2 Asset Information

A distributor should provide asset information (e.g., asset capacity and utilization; asset condition; asset risks; and asset demographics), by major asset type, that may help explain the specific need of the capital expenditures and demonstrate that a distributor has considered all economical alternatives.

5.3.2.2.1 Asset Capacity & Utilization

The chart in Figure 5.3-4 shows the historic peak load during each month over the past five years supplied from the PUC's supply network. As shown, the electrical load served by the supply system peaks during the winter season, typically in the month of January. The peak load served from the system during summer months, is typically about 30% less than the winter peak load. This prevailing seasonal loading pattern is desirable for avoiding equipment overloads, because loading capacity of the power equipment is higher during the winter months due to lower ambient temperature, when peak load occurs.

The figure also indicates a negative time trend in peak electrical demand on the distribution network. The peak load served from the system has experienced a decrease at the rate of approximately 1.2%, annually, due to a number of reasons, including the multiple CDM initiatives implemented by residential and general service customers, expansion of natural gas distribution network in the region and shifting of heating loads from electric heat to gas heating, and relatively slow growth in overall number of customers. Data in this figure was compiled in June 2022.

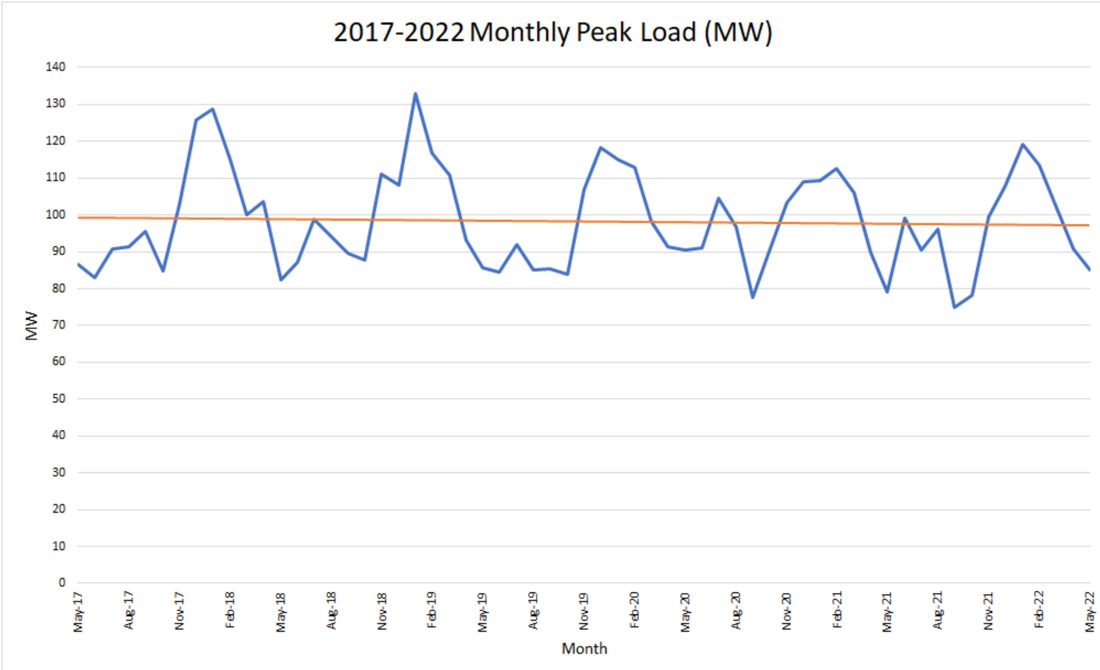


Figure 5.3-4: PUC Service Territory – Past Eleven Year System Loading

Figure 5.3-5 shows the forecasted peak electrical demand for the service area, based on which regional demand forecasts and planning have been completed and as indicated the peak demand served from the distribution network is expected to continue with a moderate decline from the current levels. Data in this figure was compiled in June 2022.

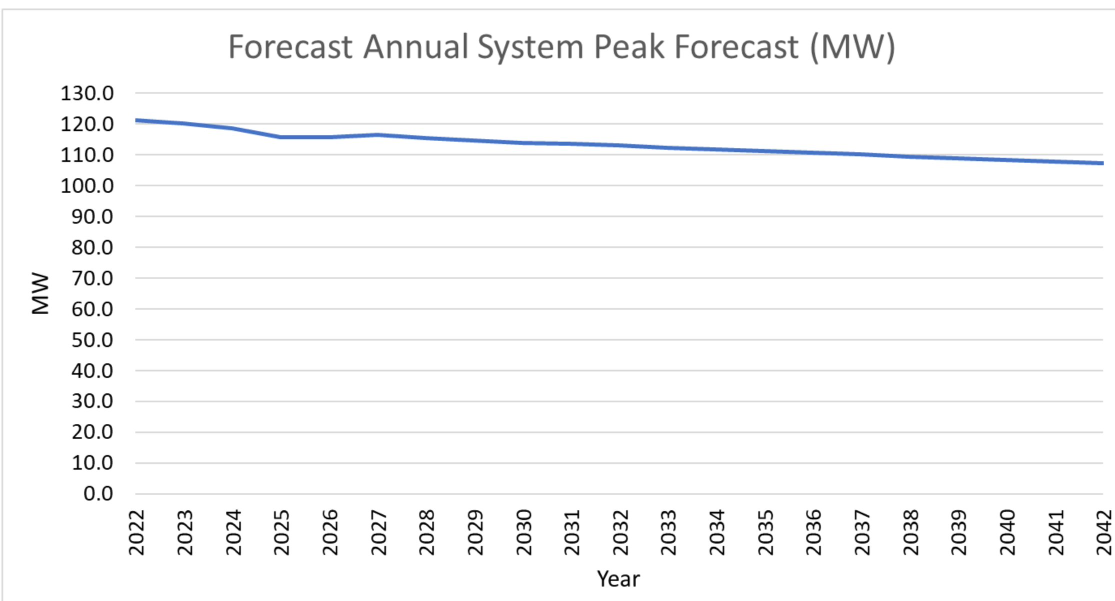


Figure 5.3-5: PUC Service Territory – Peak Demand Forecast

Figure 5.3-6 and Figure 5.3-7 indicate the peak load during the past five years for each of the power transformers. Most of the peaks are a result of picking up load from neighbouring station outages, but the transformers were still required to perform at the below levels as part of PUC's station contingency philosophy. Data in these figures were compiled in June 2022.

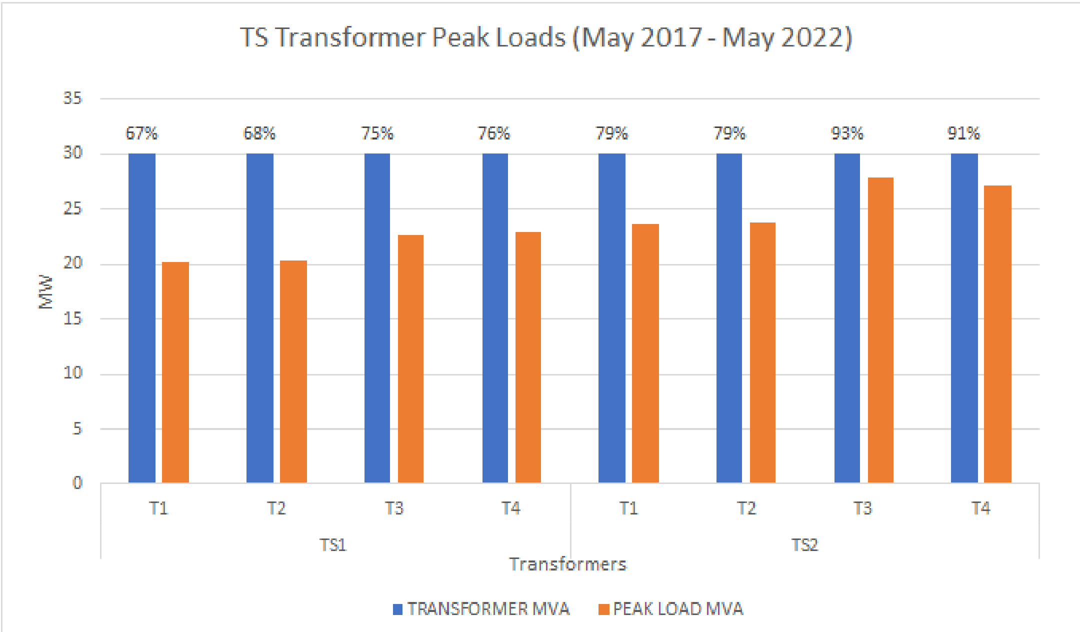


Figure 5.3-6: 34.5kV Substation Ratings and Loading Level

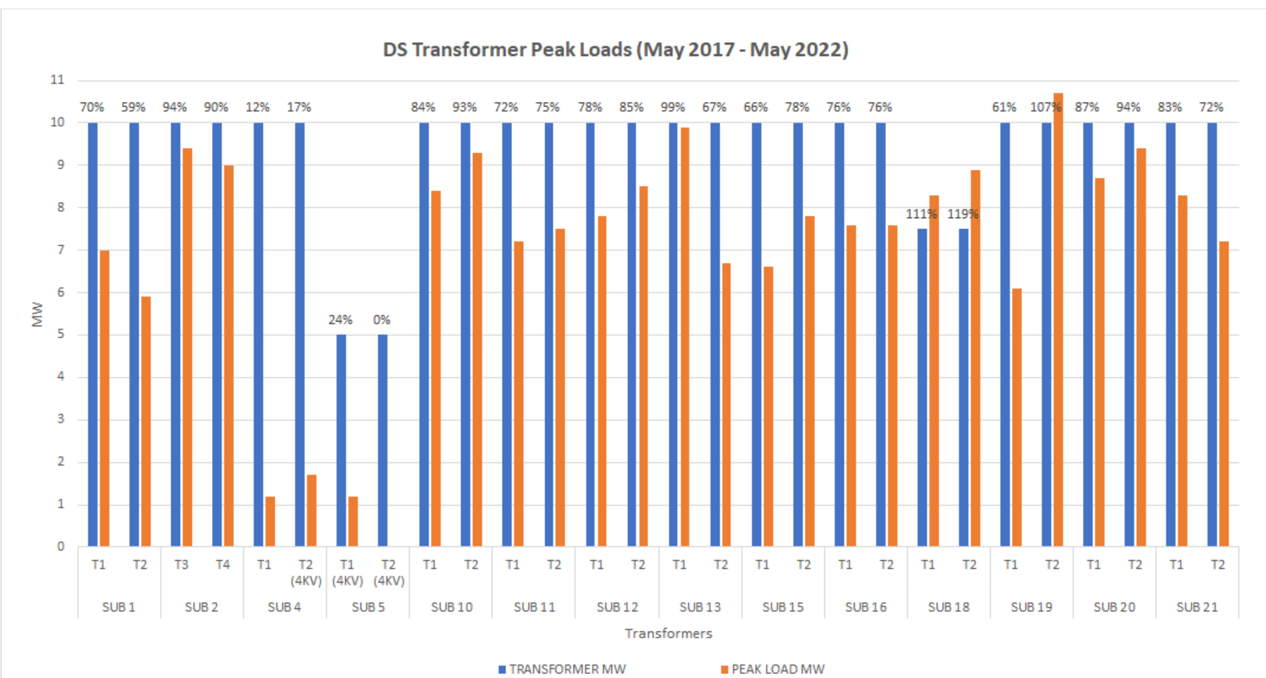


Figure 5.3-7: 12.5kV Substation Ratings and Loading Level

Over the last five years, the power transformers at Substation 18 have consistently experienced peaks over their ratings, and on average operate at about 70% of their ratings. This is demonstrated in Figure 5.3-8 below, which illustrates the monthly peak loads of both Substation 18 power transformers relative to their rating. As a result of this, Substation 18 does not have enough contingency to pick up load from neighbouring stations. This concern will be addressed with the new distribution station (Substation 22) proposed to be built within this DSP period. Additional information on the new distribution station can be found in Section 5.2.1.4.

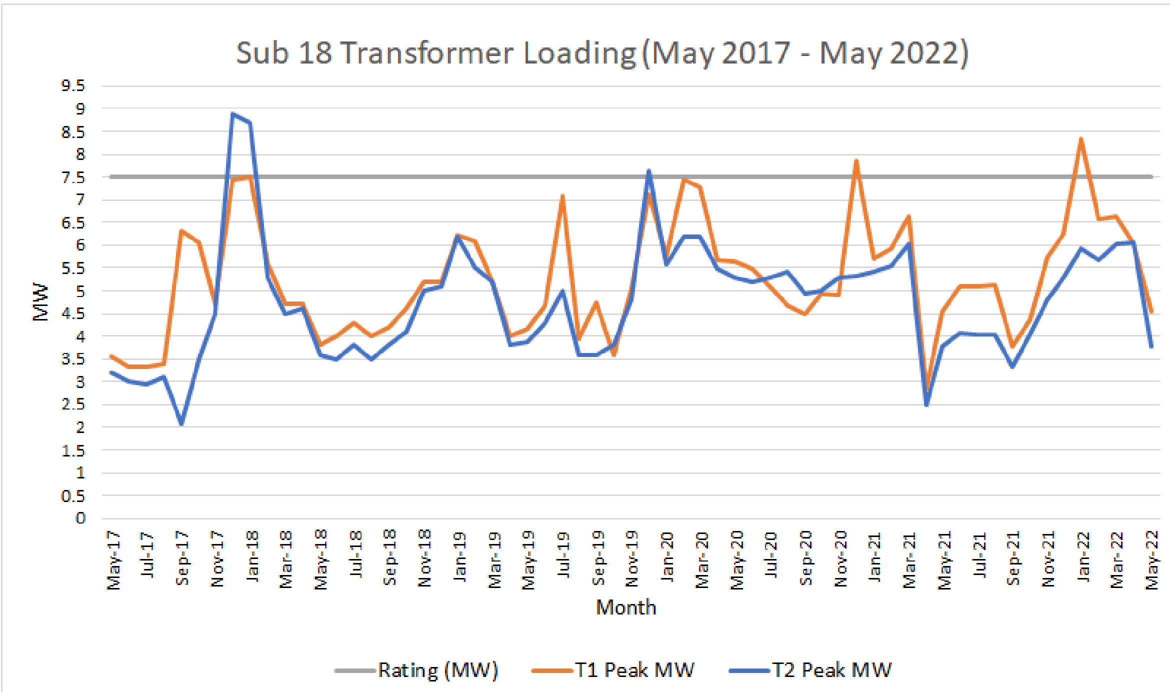


Figure 5.3-8: Five Year Sub 18 Transformer Peak Monthly Loads

5.3.2.2.2 Asset Condition & Demographics

The Asset Condition Assessment (ACA) study was carried out by METSCO for PUC to establish the health and condition of distribution and substation assets in-service. The ACA is based on data compiled to the end of September 2021. Figure 5.3-9 to Figure 5.3-11 below present the summary results of the ACA for PUC's distribution assets and substation assets. The HI is not calculated for any distribution asset with a Data Availability Indicator (DAI) less than 70% (i.e., less than 70% of the condition parameters – by weight – are available for that asset) or less than 65% for station assets. The HI results for assets with a known HI were divided into ten-year bands and extrapolated to the unknown set within those bands. The age demographics and condition breakdown for each asset class is detailed further below. The complete ACA study can be found in Appendix H of the DSP.

As referenced in Section 5.3.1.3, PUC utilizes the outputs of the ACA as a key input into it capital planning process. Where PUC has calculated valid HIs with the required data availability, it uses this information to inform which assets to potentially replace and/or repair. Where data availability is below the DAI threshold and PUC has identified the asset(s) may need attention, PUC performs further assessments, gathering further data before deciding if the asset(s) should be replaced and/or repaired.

As described further in Section 5.4.1.2.2, PUC has focussed its investment in areas where there is strong ACA data available, and where there is not, additional expenditure is focused on additional future testing, tracking and studies.

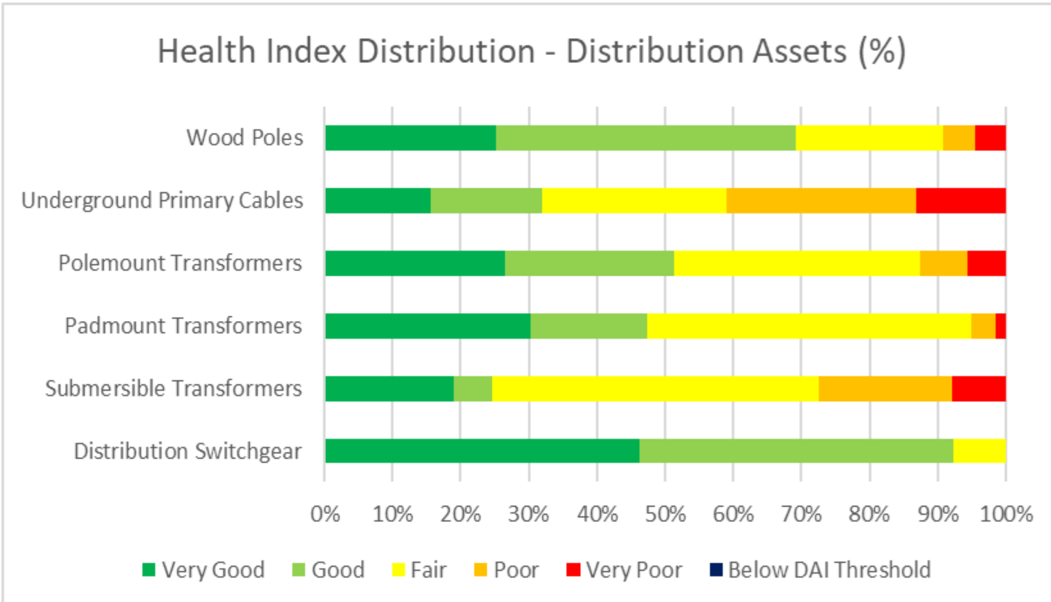


Figure 5.3-9: Distribution Assets Health Index Results

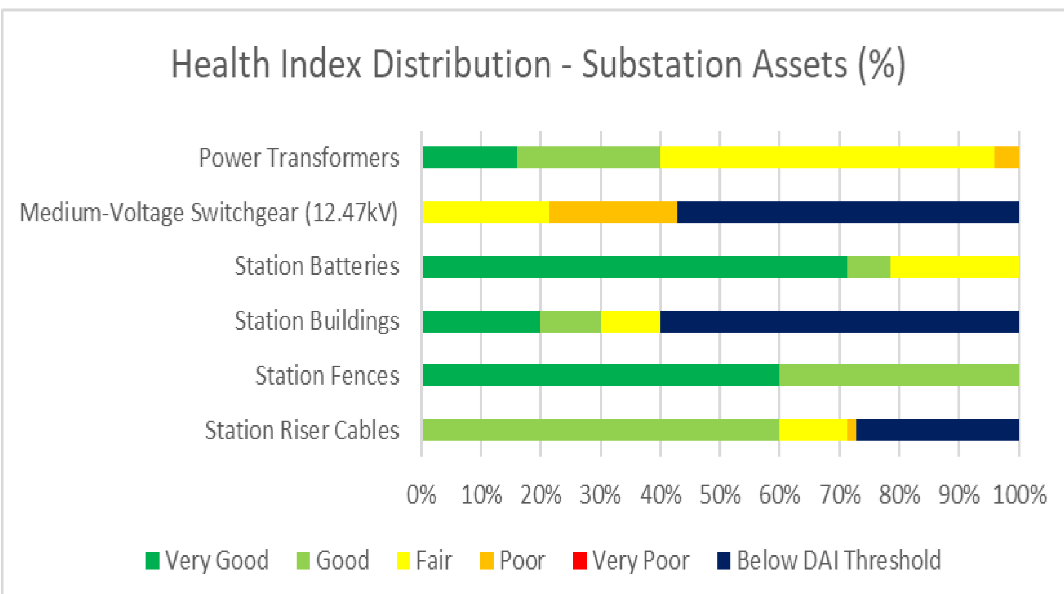


Figure 5.3-10: Substation Assets Health Index Results

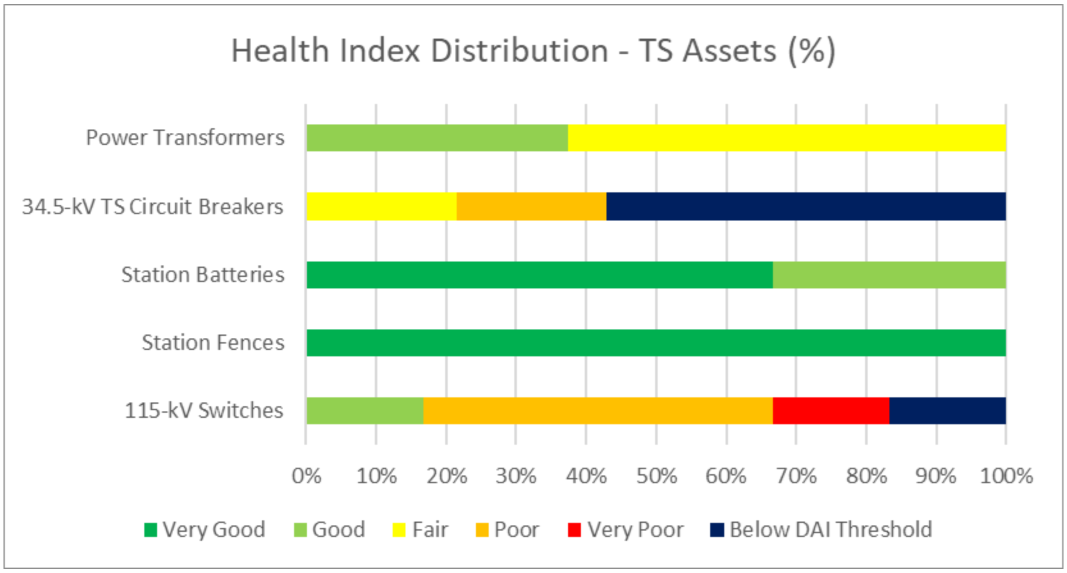


Figure 5.3-11: TS Station Assets Health Index Results

5.3.2.2.2.1 Condition of Distribution Assets

Wood Poles

Wood poles are an integral part of any distribution system. They are the support structures for overhead distribution system. PUC owns 12,548 wood poles within its service territory. Installation date is known for nearly 98% of the total in-service population. Figure 5.3-12 presents the age distribution for in-service wood poles.

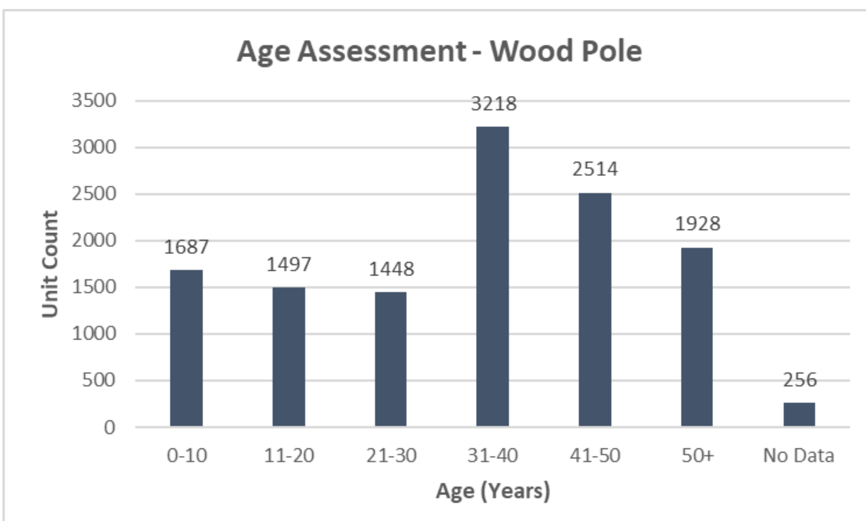


Figure 5.3-12: Wood Poles Age Demographics

A valid HI was calculated for 96% of the wood poles. To complete the full analysis, the HI for the remaining 4% of poles has been extrapolated based on the HI distribution with a valid HI score within each ten-year age group. The HI Distribution is presented in Figure 5.3-13 and most of the poles are in Very Good or Good condition with less than 12% of the total population being in Poor or Very Poor condition.

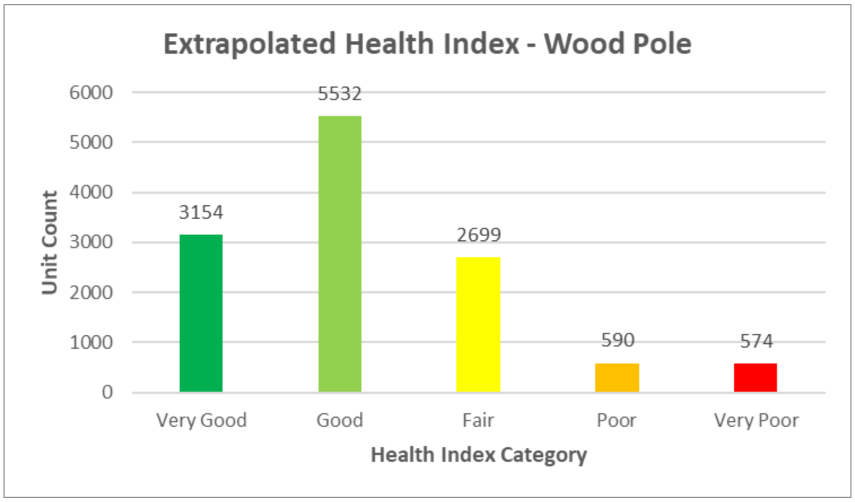


Figure 5.3-13: HI Results- Extrapolated Wood Pole

<u>Overhead Primary Conductors</u>

Overhead distribution conductors transmit electricity from generators to TS, from TS to substations, and from substations to customer premises and are supported by poles. Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for the tensile strength of the conductor and to determine the remaining life of the asset is the use of service age.

PUC owns 615 km of overhead distribution primary conductor with its service area. PUC's overhead distribution conductors operate at various voltage levels; 4.16kV, 12.47kV, 34.5kV and 115kV. An age assessment was evaluated for the overhead conductor population, Figure 5.3-14, Figure 5.3-15 and Figure 5.3-16 below represent the overhead lines age distribution.

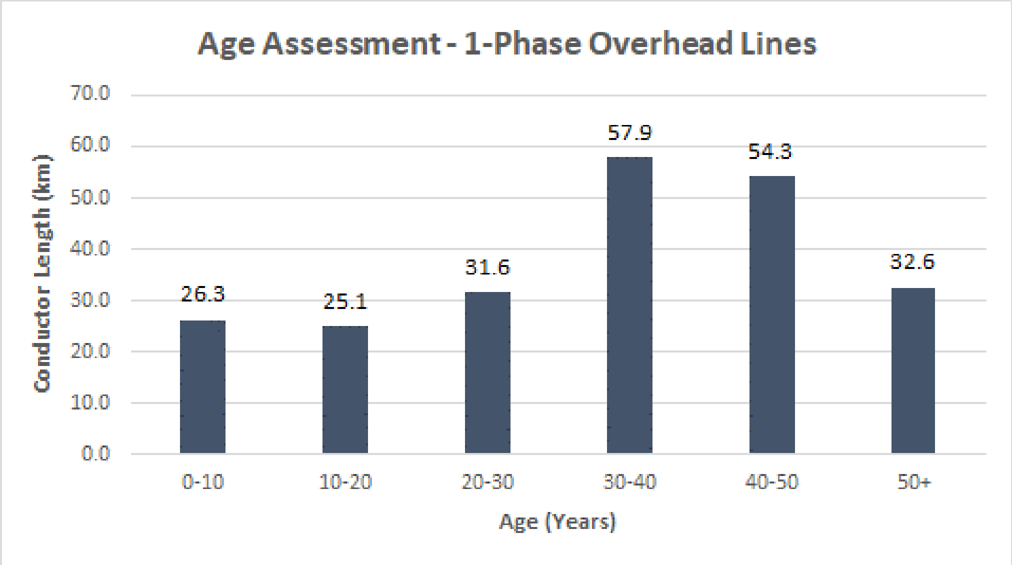


Figure 5.3-14: 1-Phase Overhead Line Age Demographics

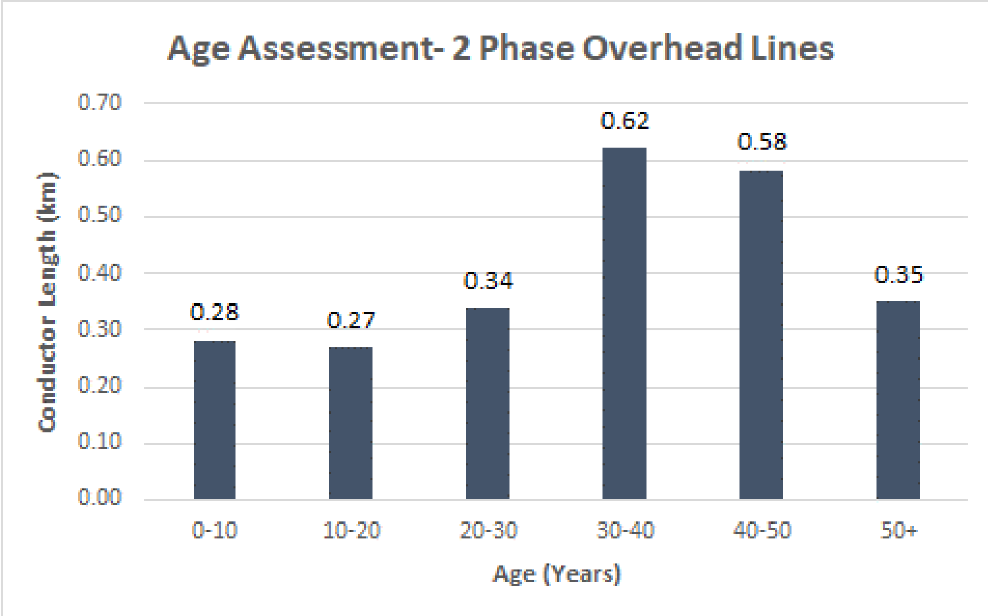


Figure 5.3-15: 2-Phase Overhead Lines Age Demographics

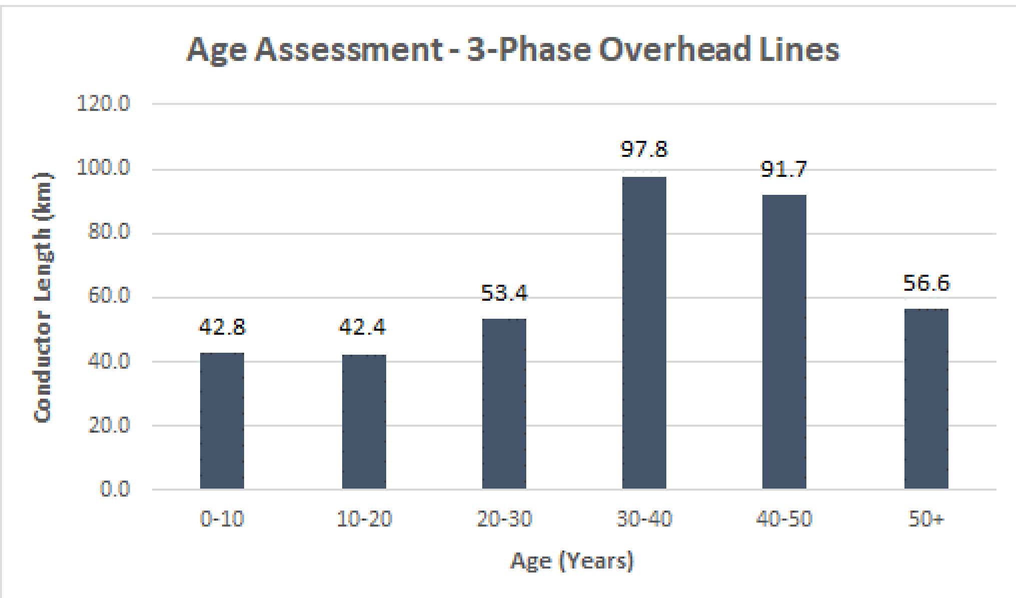


Figure 5.3-16: 3-Phase Overhead Line Age Demographics

Underground Primary Cable

Underground cables transmit electricity along the electrical distribution system. PUC owns approximately 123 km of underground primary cable within its service territory. Installation dates are known for nearly 97% of underground cable length. Figure 5.3-17 presents the age distribution by total length of underground primary cables by the cables' buried status.

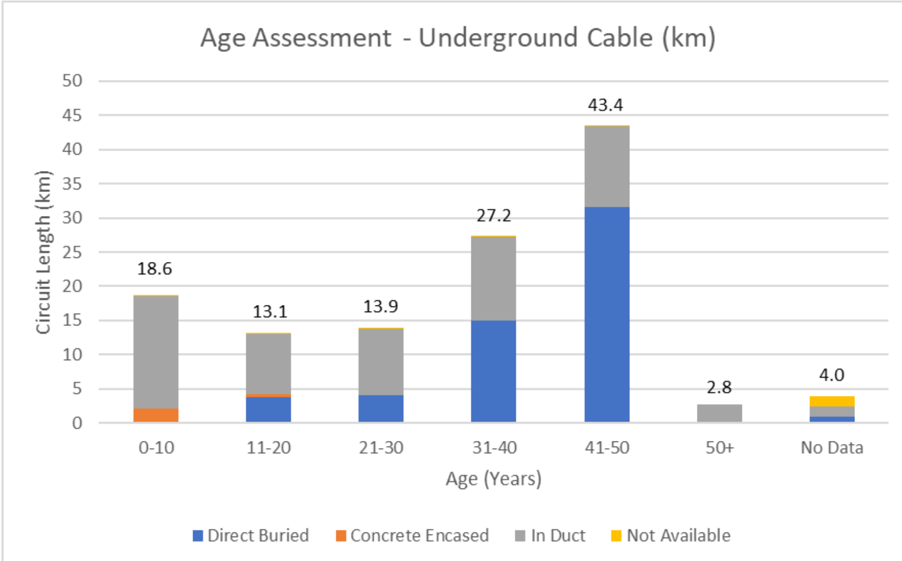


Figure 5.3-17: Overall Underground Primary Cable Age Demographics

A valid HI was calculated for 97% of underground cables, the HI for the remaining 3% of poles has been extrapolated based on the HI distribution with a valid HI score within each ten-year age group. As seen in Figure 5.3-18, approximately 40% of the population is in "Good" or "Very Good Condition" while the remaining 60% of assets lie in "Fair" condition or worse.

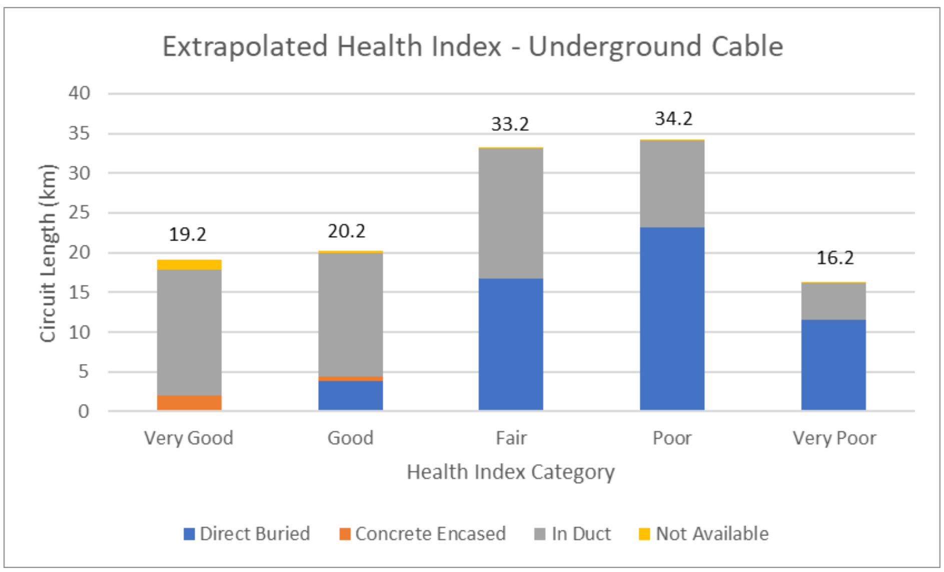


Figure 5.3-18: HI Results- Extrapolated Underground Cable

<u>Polemount Transformers</u>

Pole-mount transformers are installed on service poles above ground with the primary function to step down power from the medium-voltage distribution system to the voltage rating for customer use. PUC owns 4,806 pole mount transformers within its service territory. Installation dates are known for 99% of the total in-service population. Figure 5.3-19 presents the age distribution for polemount transformers.

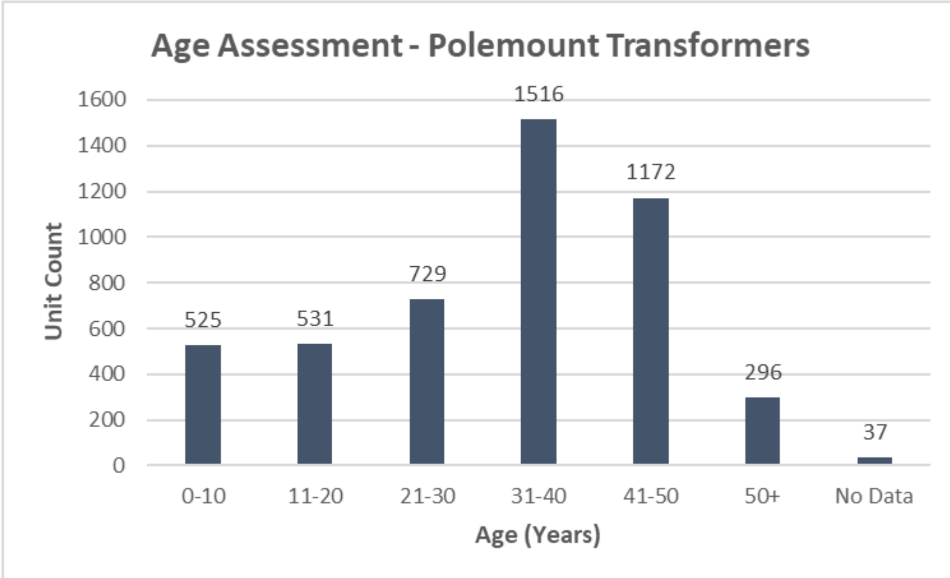


Figure 5.3-19: Pole-Mount Transformer Age Demographics

A valid HI was calculated for 90% of the overhead transformers, the HI results for the remaining 10% of pole-mount transformers were extrapolated based on the HI distribution of the asset population with a valid HI score. As see in Figure 5.3-20, nearly half of the population is in Very Good or Good condition, while over a third are in Fair condition.

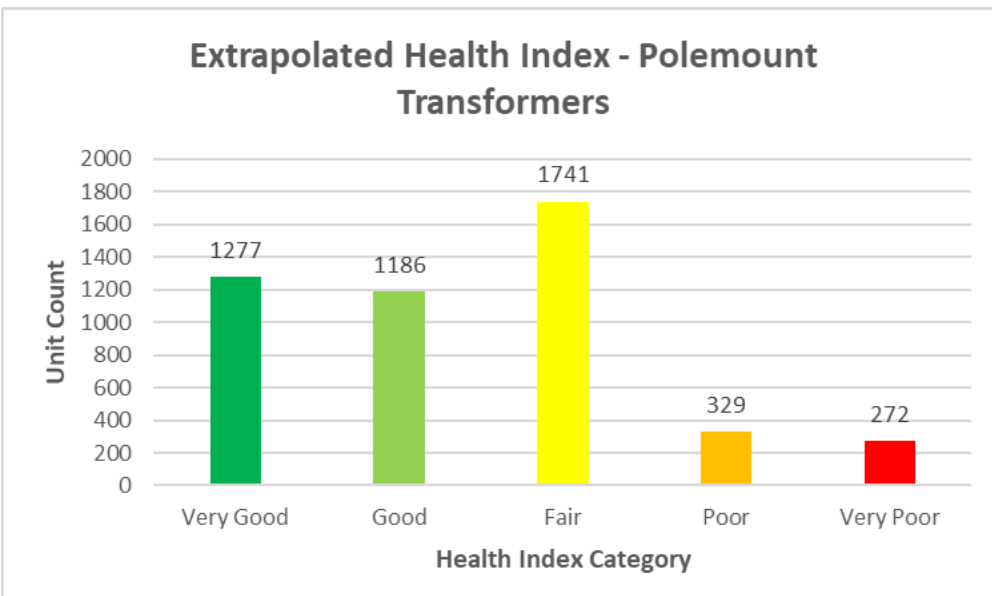


Figure 5.3-20: HI Results – Extrapolated Polemount Transformer

<u>Padmounted Distribution Transformers</u>

Places on the ground level, pad-mount distribution transformers step down power from the medium-voltage distribution system to the final utilization voltage for the customer. PUC owns 939 pad-mount transformers within its service territory. The installation dates are known for nearly the entire population. Figure 5.3-21 presents the age distribution for padmount transformers.

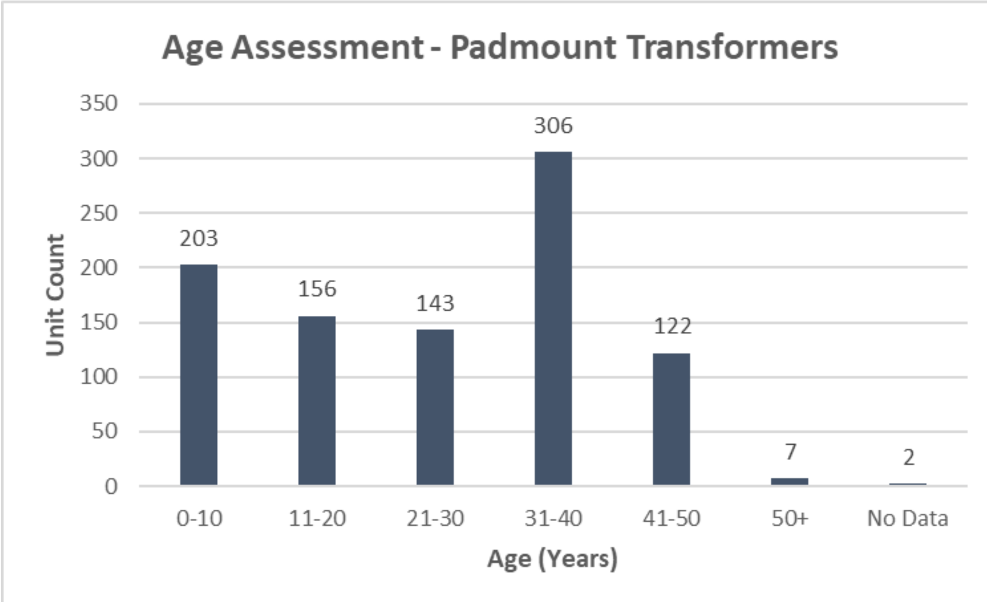


Figure 5.3-21: Pad-mount Transformer Age Demographics

A valid HI was calculated for 70% of pad-mount transformers, to complete the full analysis, the HI for the remaining population was extrapolated based on the HI distribution of the asset population with a valid HI score. As illustrated in Figure 5.3-22, most of the population is in Fair or better condition.

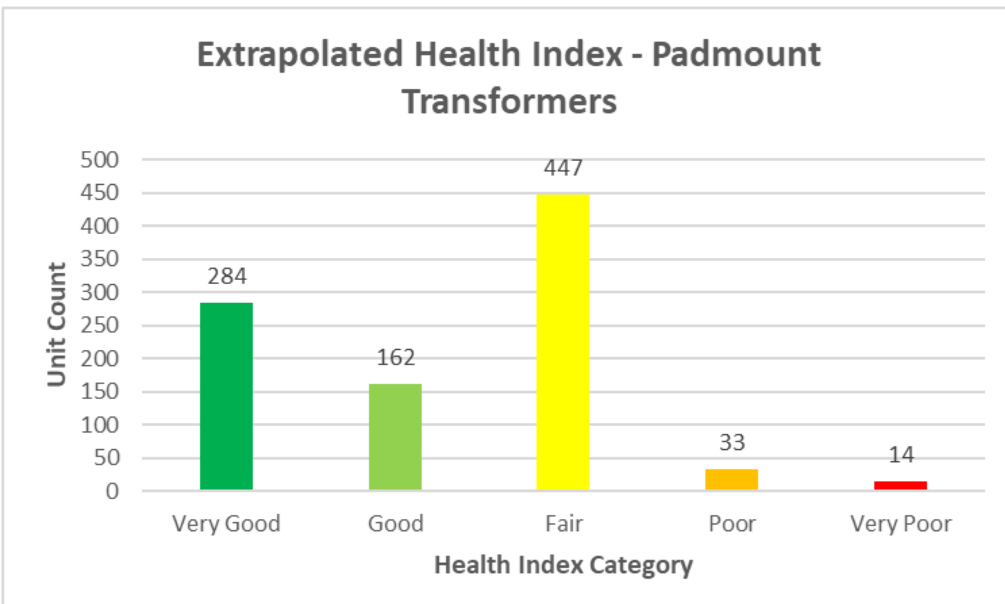


Figure 5.3-22: HI Results- Extrapolated Padmount Transformer

<u>Submersible Transformers</u>

Places below the ground level in a vault, submersible transformers step down power from the medium-voltage distribution system to the final utilization voltage for the customer. PUC owns 468 submersible transformers within its service territory. The installation dates are known for nearly the entire population. Figure 5.3-23 presents the age distribution for submersible transformers.

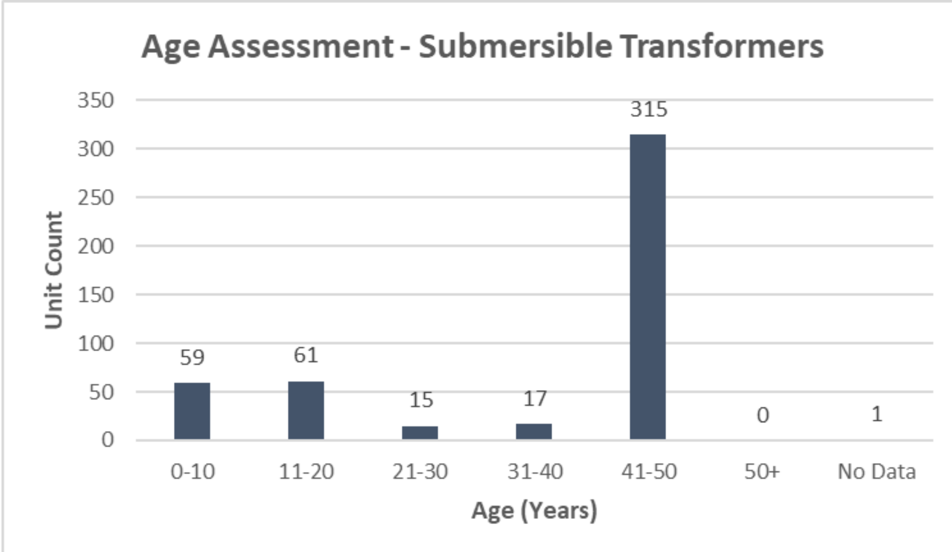


Figure 5.3-23: Submersible Transformers Age Demographics

A valid HI was calculated for 68% of submersible transformers, to complete the full analysis, the HI for the remaining population was extrapolated based on the HI distribution of the asset population with a valid HI score. As illustrated in Figure 5.3-24, over 70% of the population is either in a Fair condition or better.

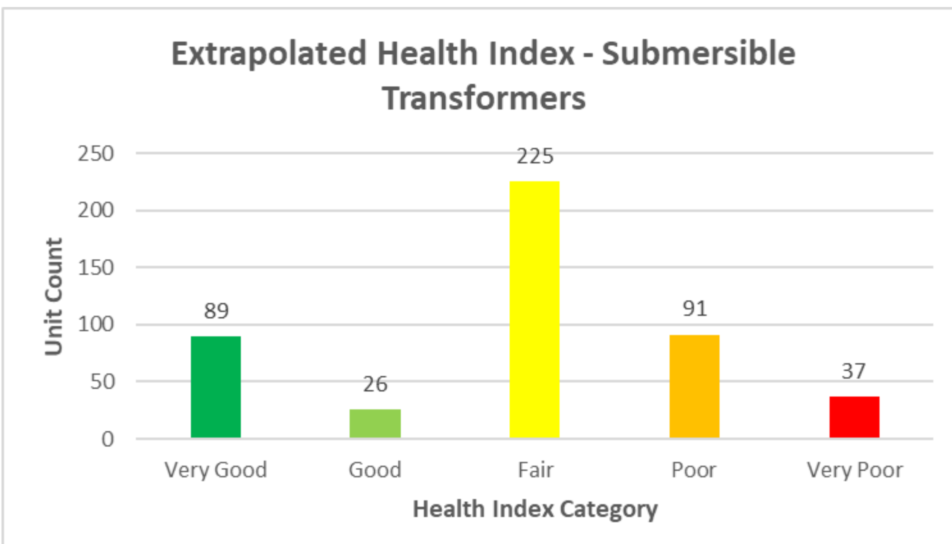


Figure 5.3-24: HI Results- Extrapolated Submersible Transformer

<u>Underground Switches</u>

PUC's underground switches are junction boxes manufactured by Kbar that can be operated if needed. PUC owns 148 underground switches within its service territory. The installations dates are known for the entire underground switch population. Figure 5.3-25 presents the age distribution for underground switches.

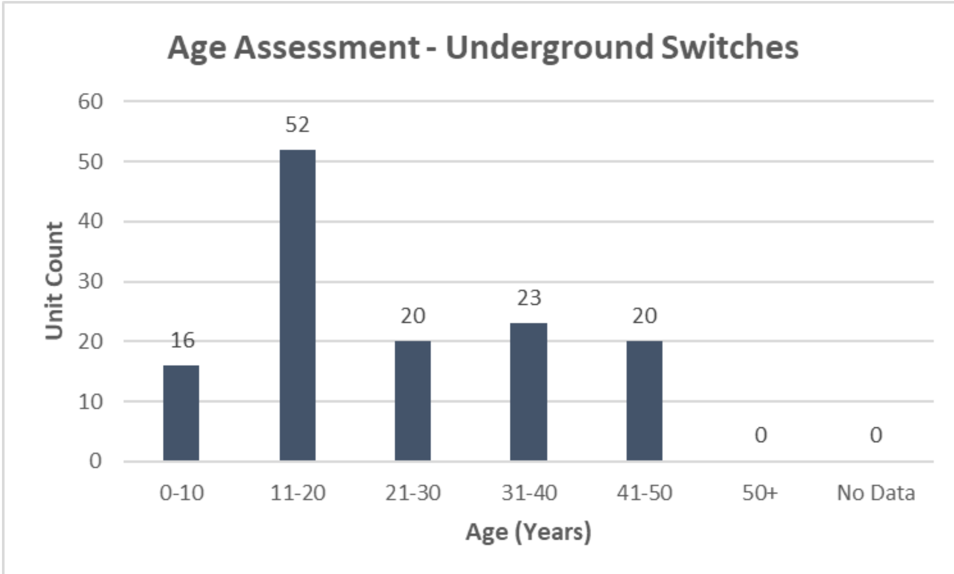


Figure 5.3-25: Underground Switch Age Demographics

A valid HI was calculated for 66% of the underground switches, the HI for the remaining population was extrapolated based on the HI distribution of the asset population with a valid HI score. As shown in Figure 5.3-26, most of the switches are in Very Good or Good condition, with less than 8% of the switches in Fair condition.

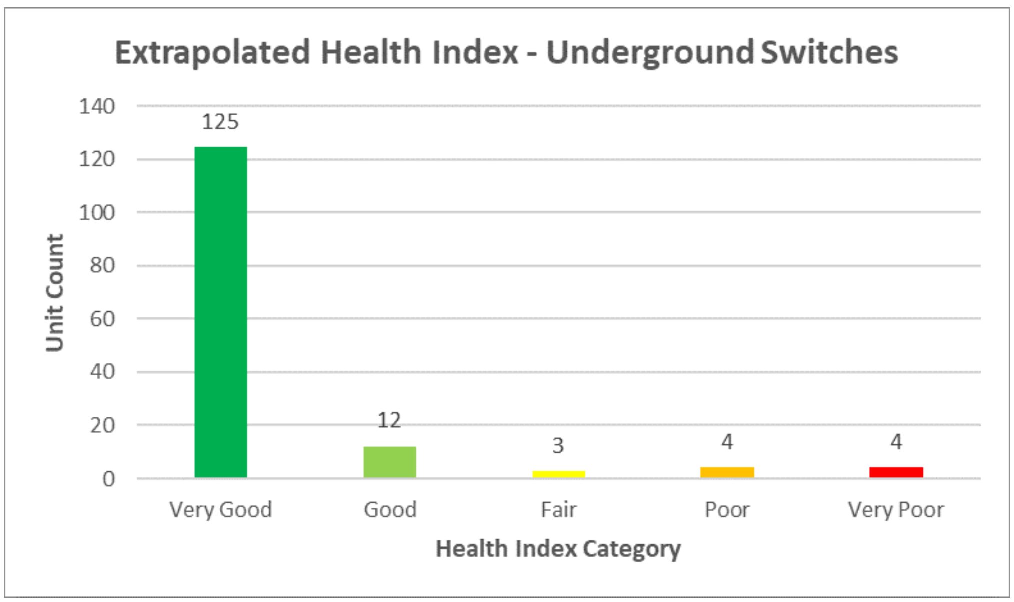


Figure 5.3-26: HI Results - Extrapolated Underground Switch

Distribution Switchgear

Distribution switchgears provide the required level of operating flexibility for the underground system. They are employed for controlling, regulating, and isolating the electrical circuit in the underground distribution system. PUC owns 25 switchgear units within its service territory. Figure 5.3-27 presents the age distribution for PUC's switchgear.

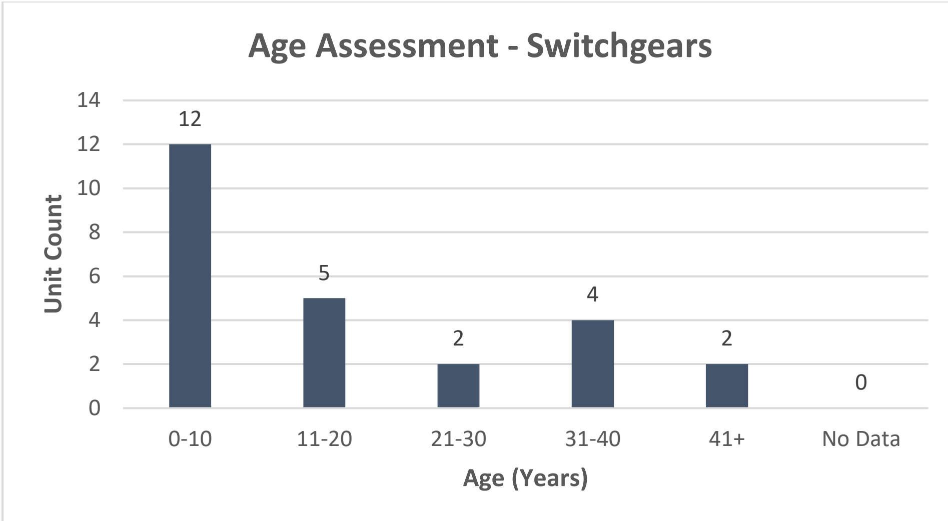


Figure 5.3-27: Switchgear Age Demographics

The overall switchgear HI distribution is presented in Figure 5.3-28. The majority of the switchgears are in Good or Very Good condition

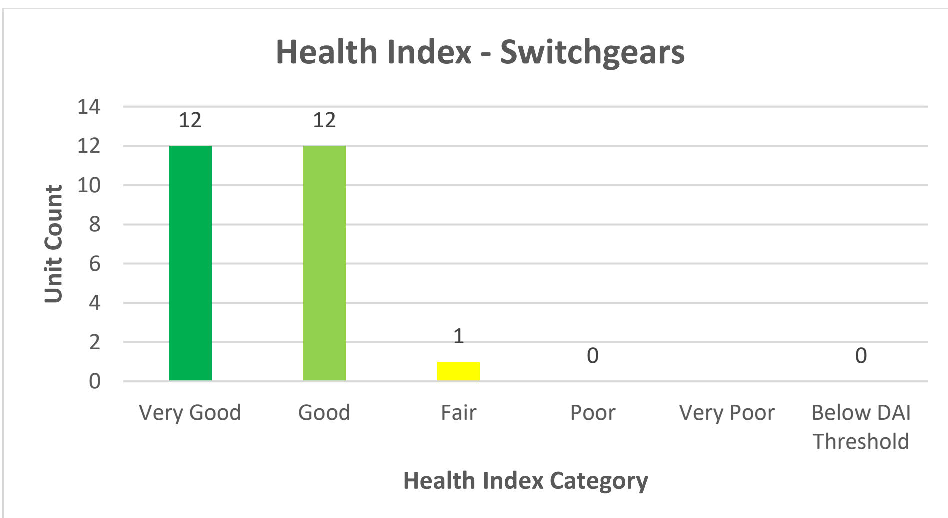


Figure 5.3-28: HI Results – Distribution Switchgear

5.3.2.2.2.2 Condition of Station Assets

<u>Power Transformers</u>

Power transformers are key stations assets owned by PUC that are used to step down the voltage from the transmission to sub-transmission systems, or from the sub-transmission system to distribution levels. PUC owns a total of 34 power transformers, 8 of which are located in transformer stations (TS), TS-1 and TS-2. Figure 5.3-29 and Figure 5.3-30 present the age profile of power transformers in-service.

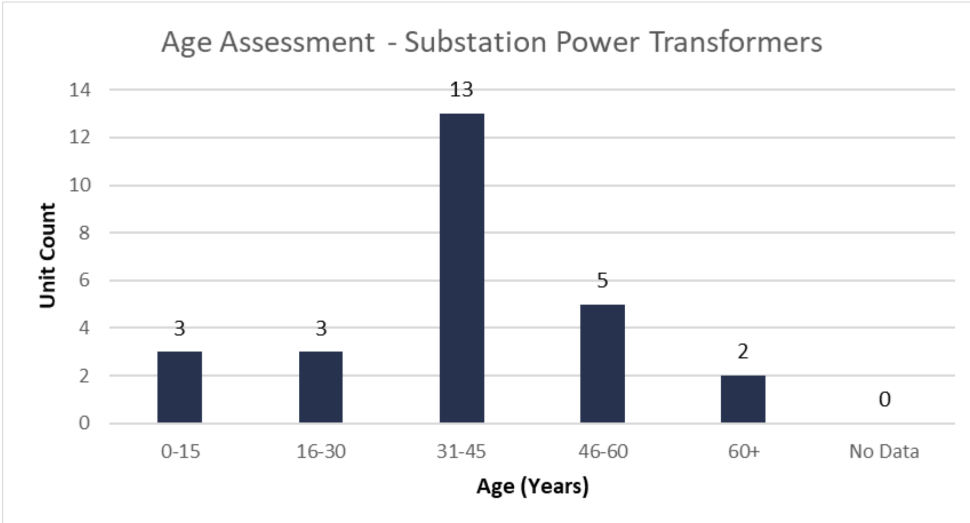


Figure 5.3-29: Substation Power Transformer Age Demographics

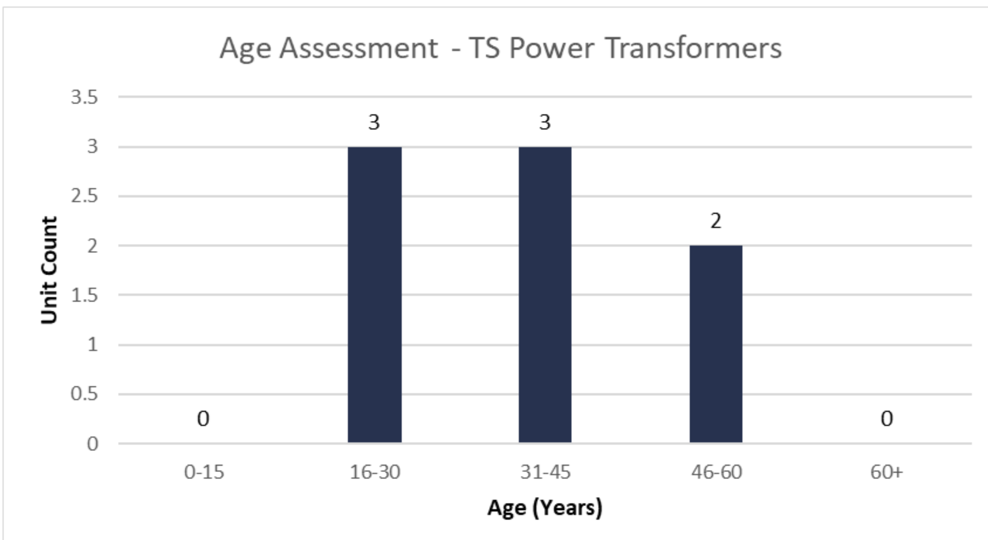


Figure 5.3-30: TS Power Transformer Age Demographics

The HI distribution for in-service power transformers is presented in Figure 5.3-31 and Figure 5.3-32. Most power transformers lie between Fair and Very Good Condition, while one transformer; Sub20_T1 is in Poor condition.

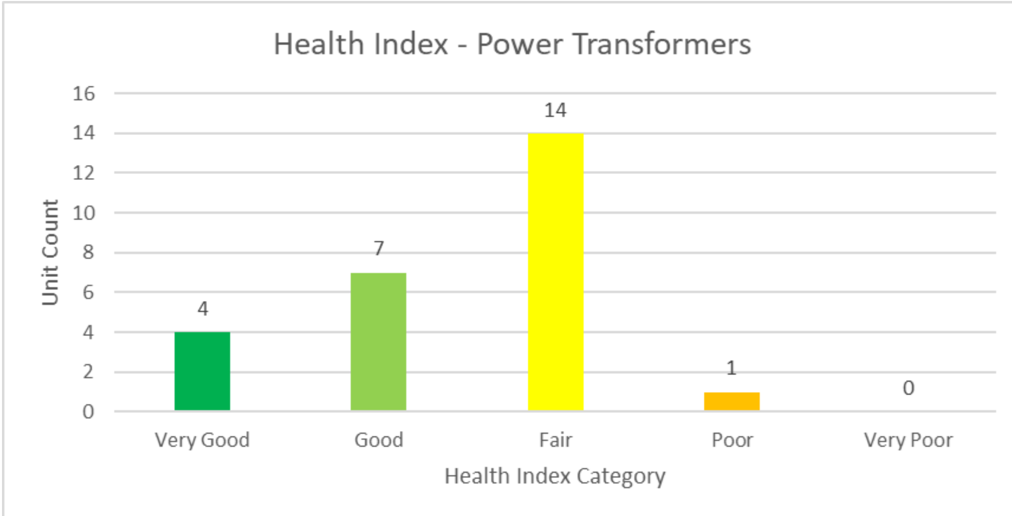


Figure 5.3-31: HI Results - Substation Power Transformer

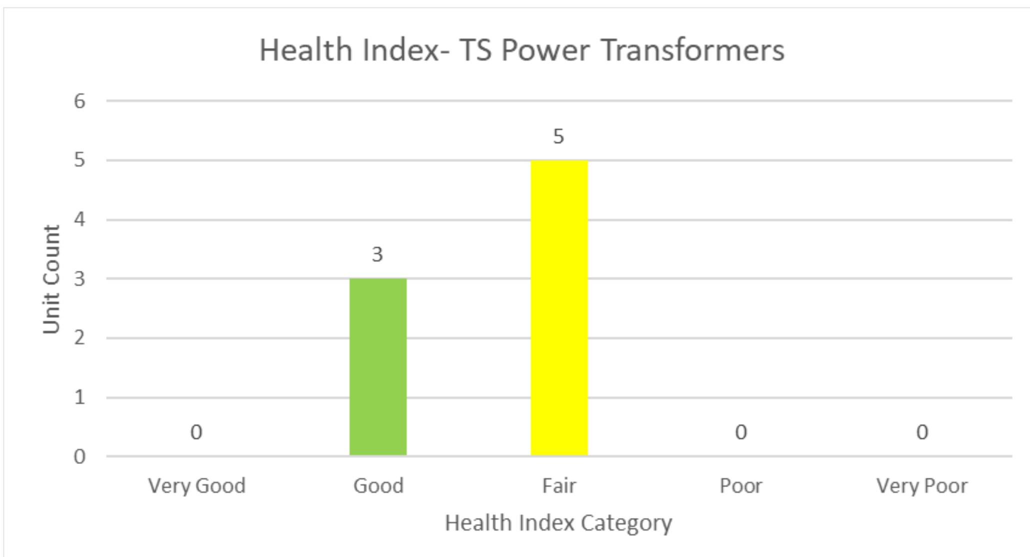


Figure 5.3-32: HI Results - TS Power Transformer

<u>Medium Voltage Station Switchgear</u>

Medium-voltage switchgear in PUC's substations operate at 34.5 kV, 12.47 kV, or 4.16 kV. They contain switching devices, circuit breakers, and measurement and control devices. PUC owns 30 medium-voltage switchgears within its substations. The age of the switchgears is known for 93% of the population. Figure 5.3-33, Figure 5.3-34, and Figure 5.3-35 present the age distribution for switchgear by voltage level.

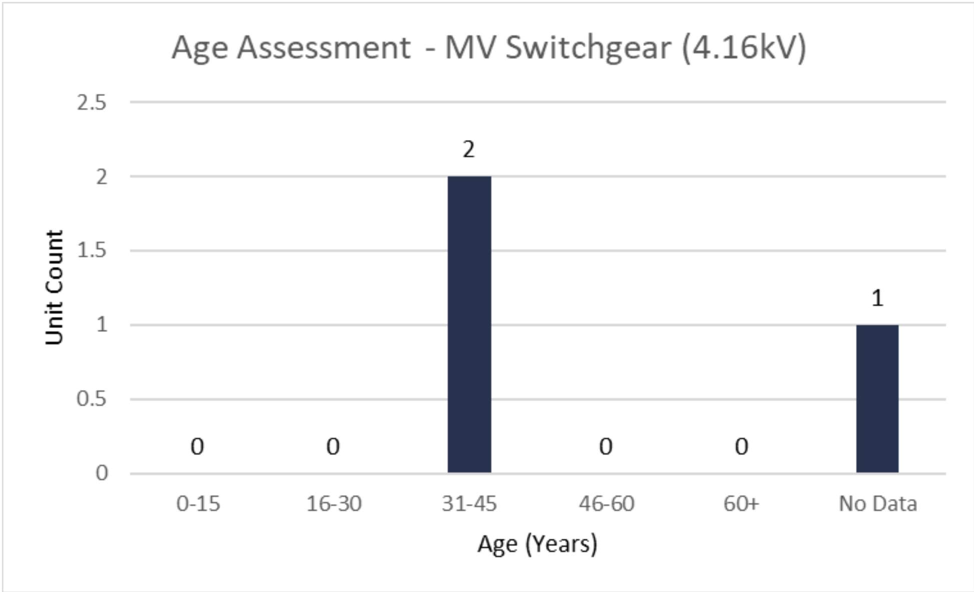


Figure 5.3-33: 4.16kV Substation Switchgear Age Demographics

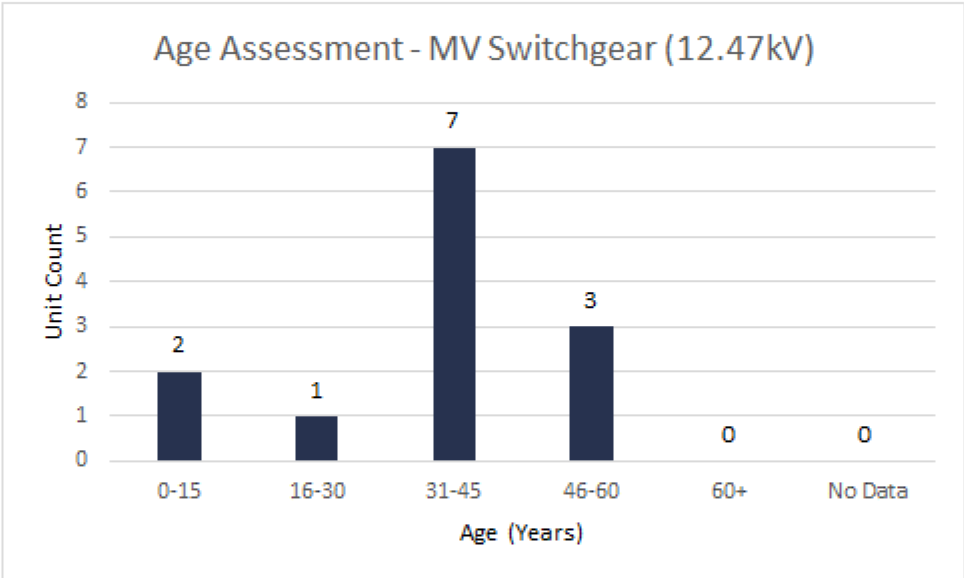


Figure 5.3-34: 12.47kV Substation Switchgear Age Demographics

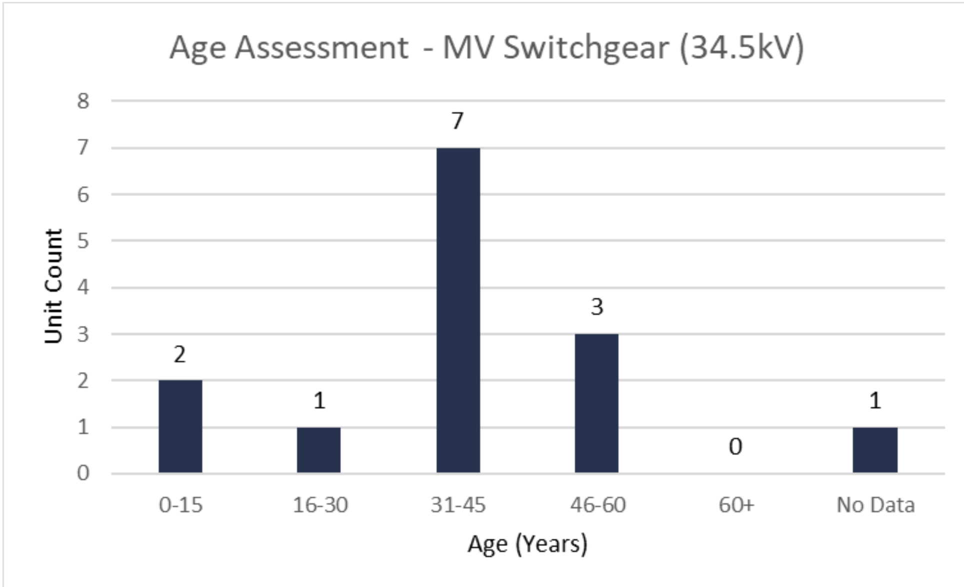


Figure 5.3-35: 34.5kV Substation Switchgear Age Demographics

A valid health index was calculated only for 12.47kV switchgear. A valid HI was calculated for 43% of the total population. As seen in Figure 5.3-36 all assets with a valid HI are in Fair or Poor condition, indicating the need for investment.

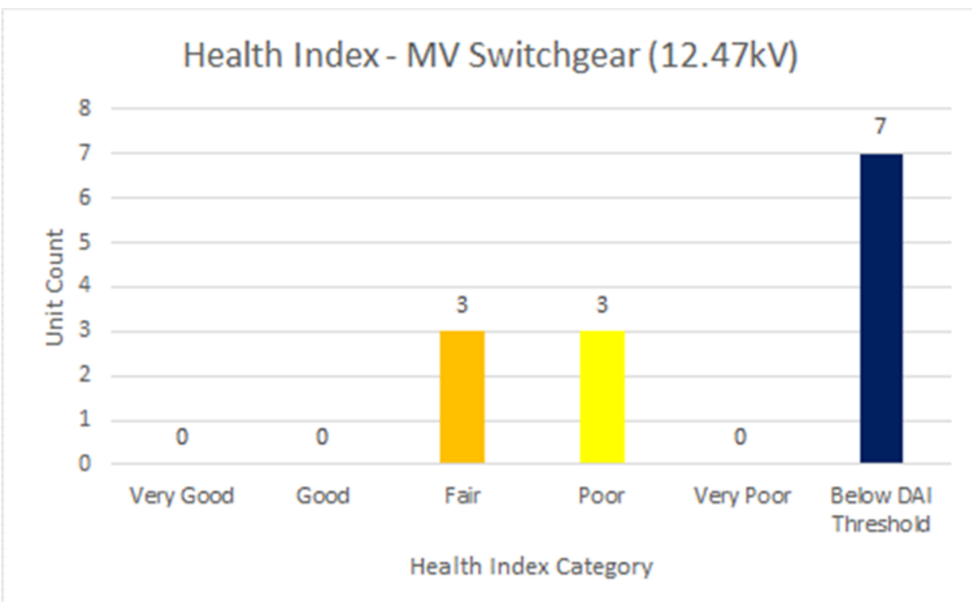


Figure 5.3-36: HI Results – Medium Voltage Switchgear

<u>34.5 kV TS Circuit Breakers</u>

Circuit breakers, located outdoors or in station switchgear, are electrical devices that operate automatically during a fault. PUC owns 22 circuit breakers operating at 34.5 kV across their transformer stations. The installation date is known for the entirety of the population. The age distribution for 34.5-kV circuit breakers is shown in Figure 5.3-37.

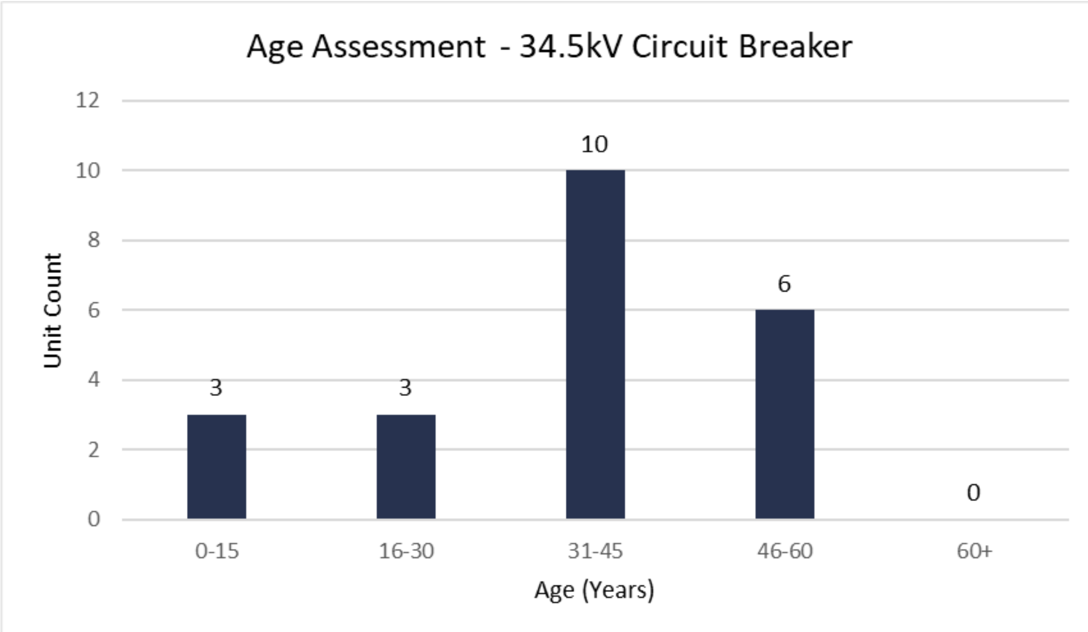


Figure 5.3-37: 34.5-kV TS Circuit Breaker Age Demographics

The HI distribution for in-service station switches is presented in Figure 5.3-38. The entire population is in “Fair” or “Poor” condition.

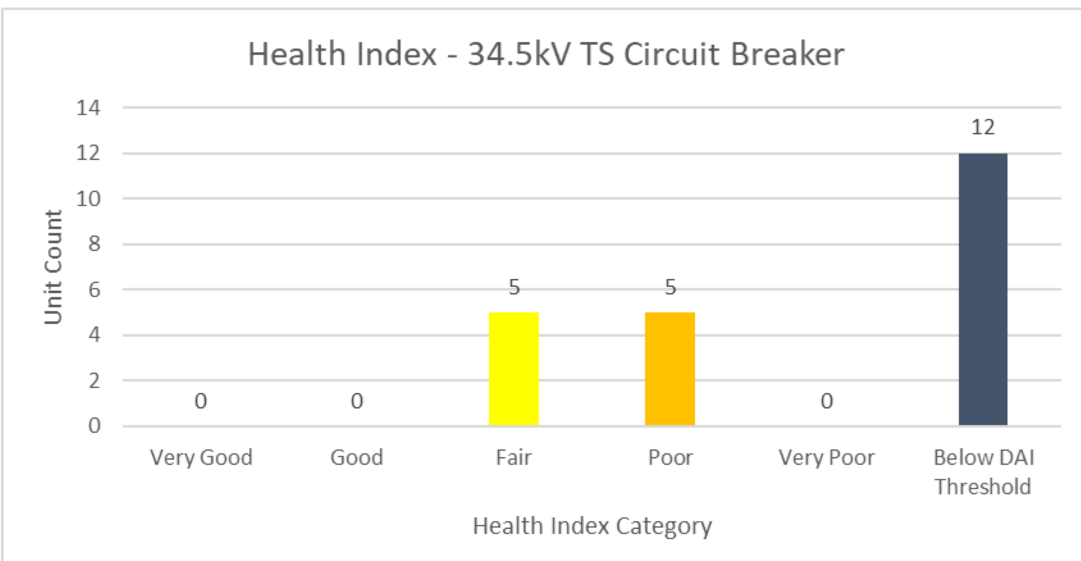


Figure 5.3-38: HI Results – 34.5kV TS Circuit Breaker

<u>Battery Banks and Chargers</u>

The battery system provides backup power to essential station functionalities such as lighting, communication, and protection/control equipment in the event of a loss of supply to the station. PUC owns 17 batteries and chargers within its stations. The asset installation years are known for all battery banks. Figure 5.3-39 and Figure 5.3-40 present the age distributions for station battery banks.

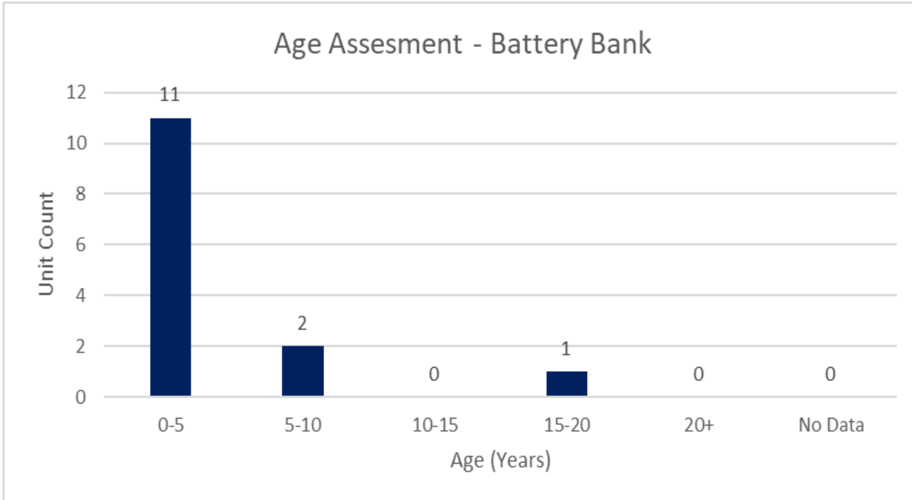


Figure 5.3-39: Substation Battery Banks Age Demographics

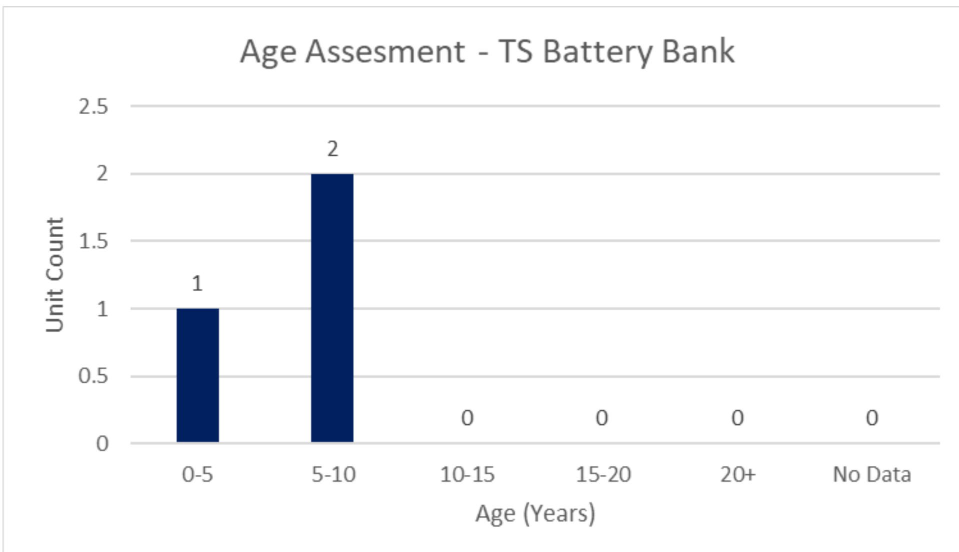


Figure 5.3-40: TS Battery Bank Age Demographics

The HI distribution for station batteries is presented in Figure 5.3-41 and Figure 5.3-42. Most batteries were in “Good” or “Very Good” condition.

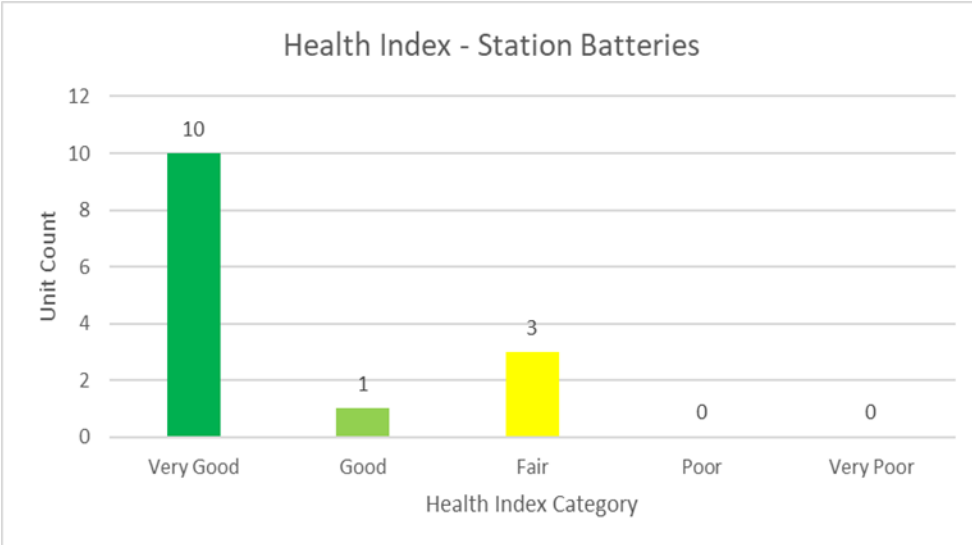


Figure 5.3-41: HI Results – Substation Battery

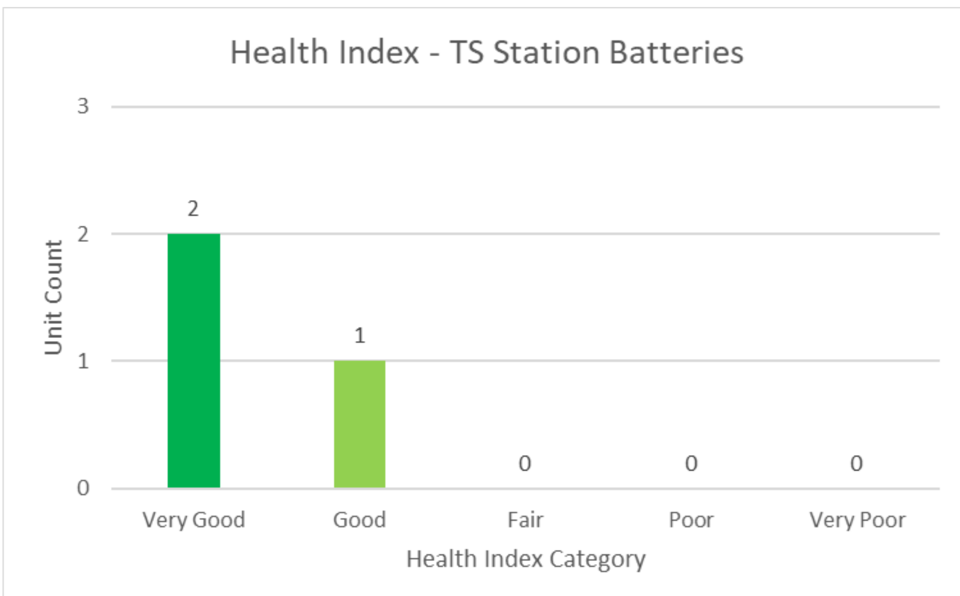


Figure 5.3-42: HI Results – TS Station Battery

<u>Station Buildings</u>

The primary function of buildings at stations is to provide a suitable environment for electrical equipment or to serve as a base for administrative and service work. PUC owns a total of ten substation buildings within its service territory. The HI distribution for station buildings is presented in Figure 5.3-43, all buildings are in fair condition or higher.

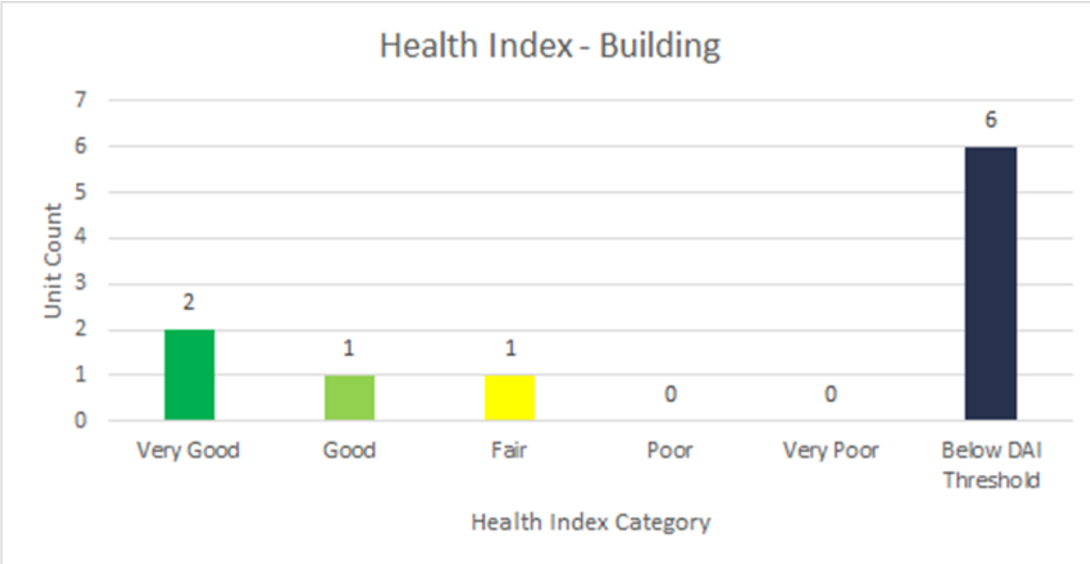


Figure 5.3-43: HI Results – Station Building

Station Fences

The integrity of fences, contribute the safety of the station and the performance of the assets therein. PUC owns a total of 12 station fences within its service territory. The HI distribution for station fences is presented in Figure 5.3-44 and Figure 5.3-45. All the population are in Very Good or Good condition.

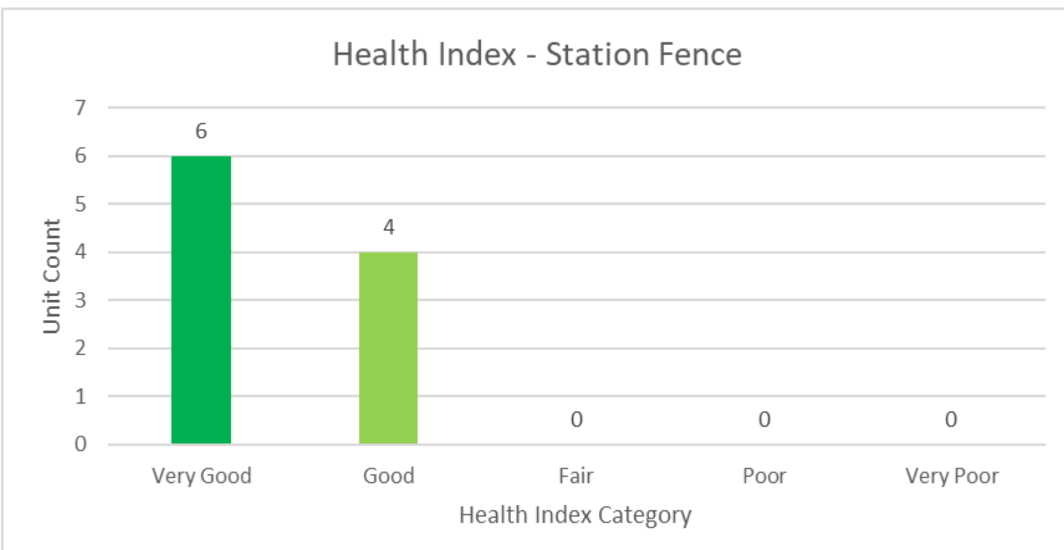


Figure 5.3-44: HI Results – Substation Fence

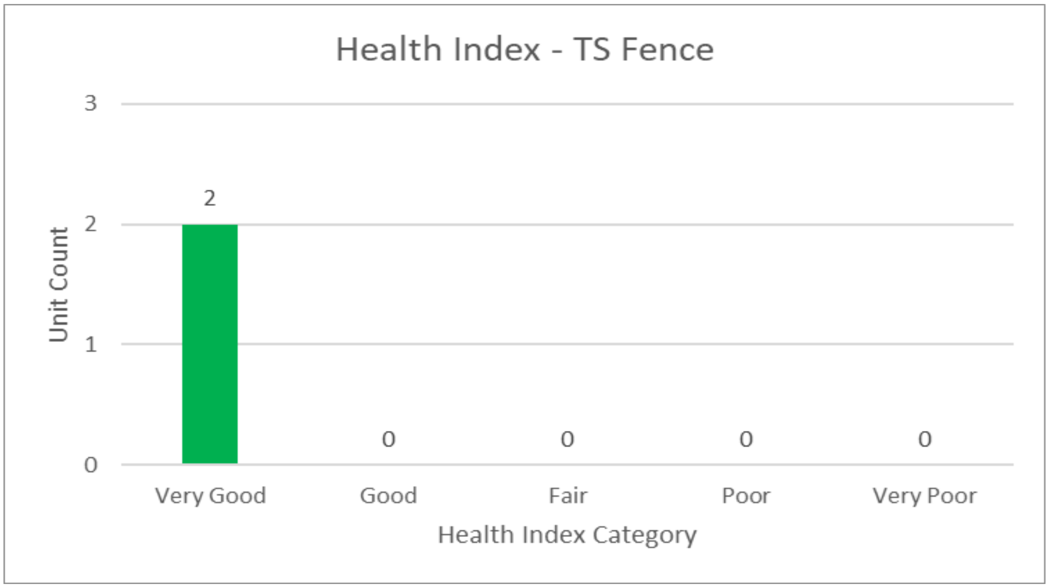


Figure 5.3-45: HI Results – TS Fence

<u>Station Riser Cables</u>

Riser cables provide a transition from underground cables to overhead lines at the egress of the station. They are critical since they carry the entire load of the feeder. PUC owns approximately 94 riser cables within their stations. As shown in Figure 5.3-46 below, a valid HI was calculated for 78% of riser cables with 71% scoring in Fair or Good condition.

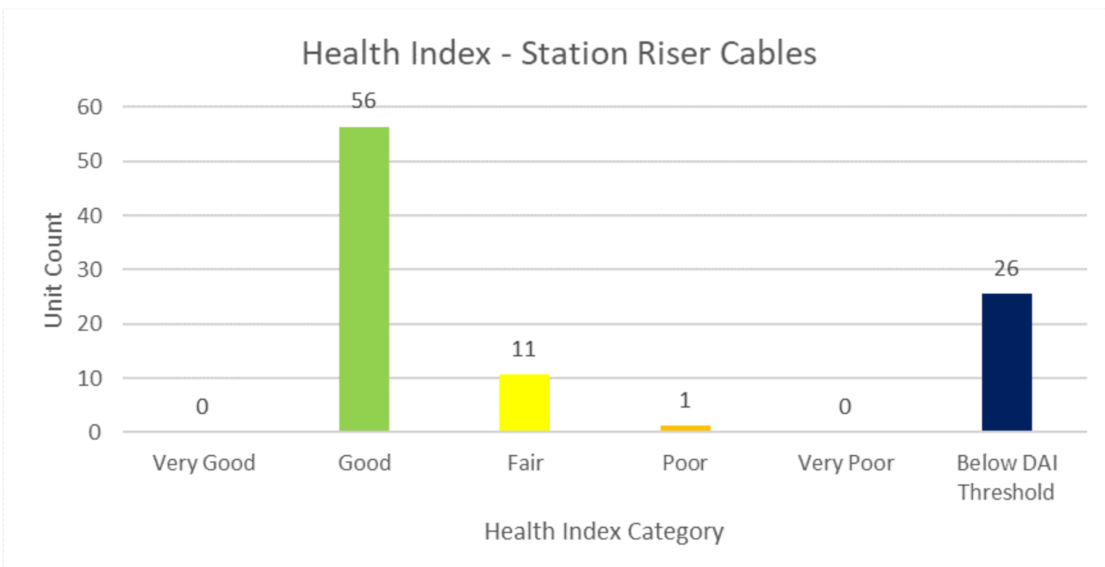


Figure 5.3-46: HI Results – Station Riser Cable

<u>115kV Switches</u>

TS switches rated for 115 kV are used to remotely isolate equipment during planned maintenance and unplanned switching operations. PUC owns 12 115 kV switches within its two TS. A valid HI was developed for 10 of the 115-kV switches while the remaining two were not inspected. As seen in Figure 5.3-47, six of the switches are in Poor condition and two are in Very Poor condition.

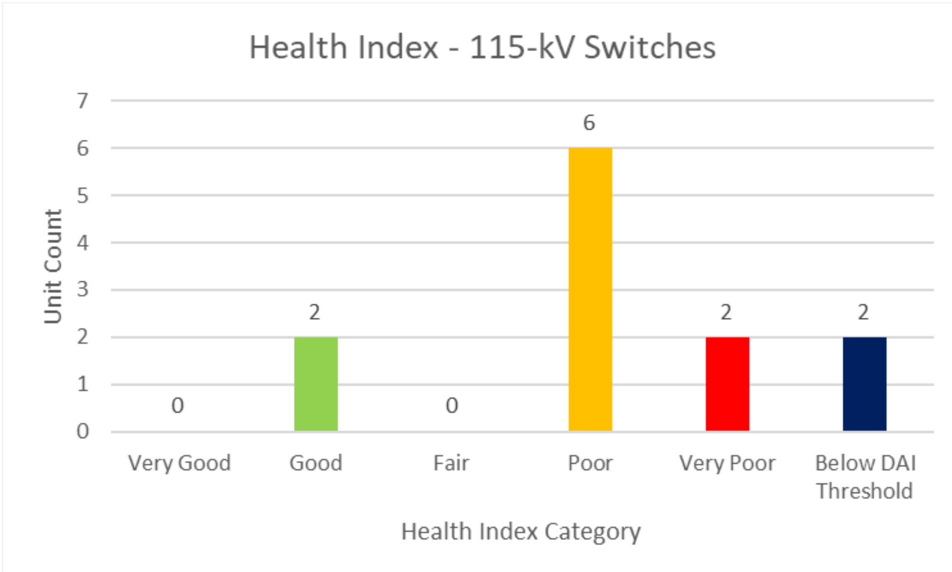


Figure 5.3-47: 115-kV Switches HI Results

5.3.2.2.2.3 Health Index Improvements

For select asset classes, a recommended HI formulation was used for PUC's ACA framework. The following set of recommendations target additional condition parameters that can be incorporated for specific asset classes to improve the HI formulation and provide PUC with additional data to refine its asset condition calculations. The recommendations are based on improving the ACA framework over time and should not be interpreted as suggesting that immediate action is warranted. The following tables highlight the condition parameter name, a brief description of the reasoning to include the condition parameter, and a priority of importance to include it in the specific asset class HI framework. The priority is dependent on the condition parameter's weighting in comparison to the current HI framework condition parameter's weights.

As described in Section 5.4.1.2.2, PUC has allocated additional expenditure that will focus on addressing these recommendations where appropriate. This includes investing in further testing, tracking and studies that will allow for more asset data to be collected that can help PUC in its capital planning process in determining which assets may require investment.

1. **Wood Poles**

Parameters which are already covered by PUC's inspectors and contractors should be explicitly added to inspection forms so they can be included in future HI formulations.

Table 5.3-14: Data Collection Recommendation for Wood Poles

Criteria	Reasoning	Priority
Wood Rot	Wood rot identifies the degree of surface or internal decay and can be determined without use of special equipment.	Medium
Out of Plumb	Pole with excessive lean face a different load profile and are more prone to failure during extreme weather events.	Low

2. Underground Primary Cables

PUC has not experienced many cable failures on its system until the previous few years; however, should their rate of failure continue increase, then it would be prudent to perform more detailed analysis into cables. Recommended analyses include detailed post-mortem analysis of failed cable samples, aggregate failure/reliability analysis linked to underground cables, and cable testing to ascertain in-field condition. Cable loading is also a useful indicator of thermal degradation.

Table 5.3-15: Data Collection Recommendation for Underground Cable

Criteria	Reasoning	Priority
Aggregate Cable Failure Analysis	Collecting high-quality failure and reliability data for all assets – including cables – is critical for understanding the reliability of the system. PUC should establish a rigorous progress for coding failure and reliability data by the asset or event from which the failure originated.	High
Post-mortem Analysis	Identifying water tree samples throughout the service territory and varying age, the utility would be able to have an improved view on cable conditions within the system.	High
Condition of Concentric Neutral	Corrosion of concentric neutrals is another mode of degradation. Insulation degradation and cable failures can be accelerated if the cable jacket is damaged allowing moisture to enter into the insulation system. Concentric neutral corrosion is a major problem particularly on unjacketed cables or when the neutrals of the cable are exposed to excessive moisture over time. The corrosion can lead to premature cable failures and/or cause touch potential risks. Time Domain Reflectometry (TDR) tests are performed to determine the degree of corrosion on concentric neutral cables.	Medium
Loading History	Cable degradation can also occur due to overheating under overloading or short circuit conditions. Over stressing of insulation during voltage surges can also lead to cable failures.	Low

3. Pole-mount Distribution Transformers

Pole-mount transformers are inspected as part of the regular line patrol process, but these results are not logged. A detailed visual inspection of the pole-mount transformer can be done during line patrols, pole inspections, or other programs, and the results recorded for use in the ACA. IR scans can detect hot spots in the tank or connectors.

Table 5.3-16: Data Collection Recommendation for Overhead Distribution Transformers

Criteria	Reasoning	Priority
Visual Inspection	To identify if the transformer is subject to any physical damage, oil leak, or corrosion.	Medium
IR Scans	To identify hotspots on the tank, connectors, etc. during transformer operation.	Low

4. Pad-mount and Submersible Distribution Transformers

IR scans can also be applied to submersible and pad-mount transformers. Pad-mount transformers can be more difficult and costly to scan since the box needs to be opened, requiring a hold-off.

Table 5.3-17: Data Collection Recommendation for Distribution Transformers

Criteria	Reasoning	Priority
IR Scans	To identify hotspots on the tank, connectors, etc. during transformer operation.	Medium

5. Underground Switches

Similar to distribution transformers, underground switches can be checked for hotspots using an IR camera.

Table 5.3-18: Data Collection Recommendation for Underground Switches

Criteria	Reasoning	Priority
IR Scans	To identify hotspots on the switch contacts, etc. when carrying current.	Medium

6. Station Power Transformers

PUC has a robust inspection and preventative maintenance program for station power transformers. The following tests are commonly applied by utilities in Ontario and can supplement PUC's present-day program to help identify adverse conditions before they develop into failures.

Table 5.3-19: Data Collection Recommendation for Power Transformers

Criteria	Reasoning	Priority
Turns Ratio Test	To compare the actual turns ratio vs. design rating and between phases.	Low
Winding Resistance	To identify degradation of the transformer winding based on the measured resistance.	Low

7. Station Riser Cables

Since PUC's station riser cables are aged and carry the full load of the feeder, PUC should prioritize collecting nameplate, visual inspection, and loading for these assets to form a condition assessment in the future.

Table 5.3-20: Data Collection Recommendation for Station Riser Cables

Criteria	Reasoning	Priority
Visual Inspection	To identify chips/cracks in the arrester, degradation of the cable terminations, or corrosion of the riser.	High
Loading	To identify overloaded cables that are undergoing increased thermal stresses.	High

5.3.2.2.3 Asset Risks

Asset risks (probability of failure x consequence of failure) are considered as part of PUC's prioritization process (step 2 of PUC's AM process shown in Figure 5.3-1) and are ultimately used to determine the prioritized list of capital projects and programs over the forecast period. Additional information on asset risks can be found in Sections 5.3.1.3 and 5.3.3.3.

5.3.2.3 Transmission or High Voltage Assets

There should also be a statement as to whether or not the distributor has had any transmission or high voltage assets (> 50kV) deemed previously by the OEB as distribution assets, and whether or not there are any such assets that the distributor is asking the OEB to deem as distribution assets in the present application.

PUC has the following high voltage assets:

- 115kV/34.5kV Transformer Station TS-1 (St. Mary's)
- 115kV/34.5kV Transformer Station TS-2 (Tarentorus)
- Four 115kV lines supplying the two above noted transformer stations

These assets are deemed as distribution assets and PUC does not seek to change their status to transmission assets.

5.3.2.4 Host & Embedded Distributors

A distributor should also provide a description of whether the distributor is a host distributor (i.e., distributing electricity to another distributor's network at distribution-level voltages) and/or an embedded distributor (i.e., receiving electricity at distribution-level voltages from any host distributor(s)). The distributor must identify any embedded and/or host distributor(s). Partially embedded status (i.e., where part of the distributor's network is served by one or more host distributors but where the utility is also connected to the high voltage transmission network) must be clearly identified, including the percentage of load that is supplied through the host distributor(s). If the distributor is a host distributor, the distributor should identify whether there is a separate Embedded Distributor customer class or if any embedded distributors are included in other customer classes (such as GS > 50 kW).

PUC is not a host distributor nor an embedded distributor. PUC receives electricity from Hydro One at transmission-level voltages only. There are also no embedded distributors served from PUC's distribution system.

5.3.3 Asset Lifecycle Optimization Policies and Practices

PUC's assets are managed based on a lifecycle management approach, which considers and balances asset performance, costs, and associated risks during the asset service life to achieve asset optimization. PUC investigated the relationship between capital spending and system O&M costs.

5.3.3.1 Asset Replacement and Refurbishment Policy

An understanding of a distributor's asset lifecycle optimization policies and practices will support the regulatory assessment of system renewal investments and decisions to refurbish rather than replace system assets. Information provided should be sufficient to show the trade-off between spending on new capital (i.e., replacement) and life-extending refurbishment.

The life cycle optimization policies and procedures employed by PUC include determining the optimal time and scope of the most effective risk mitigation option, through trade-offs between capital expenditure, preventative maintenance, and reactive maintenance. Figure 5.3-48 shows the basic decision support model employed by PUC in preparing this distribution plan, to determine the scope and timing of the investments. With increase in an asset's service age, its operating condition degrades, thus increasing the risk of the asset failing in service. In the absence of any intervention in form of asset renewal or asset refurbishment or repair, the consequential risk cost would continue to increase. When a risk mitigation intervention is implemented through an investment, the risk cost curve resets, triggering a benefit in form of reduced risk. In preparing the DSP, the timing and size of investments have been selected to minimize the "Total Cost" of the risk and the risk mitigation initiatives.

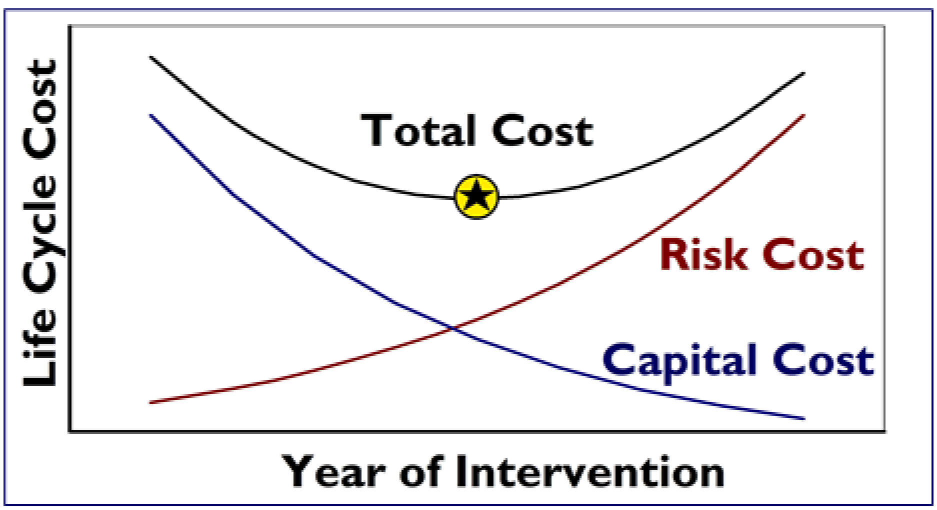


Figure 5.3-48: Risk Based Decision Support System

5.3.3.2 Description of Maintenance and Inspection Practices

A distributor should also be able to demonstrate that it has carried out system operations and maintenance (O&M) activities to sustain an asset to the end of its service life (can include references to the Distribution System Code).

Proper maintenance is essential to prolong asset lifecycles and maintain system reliability. PUC's maintenance program employs equipment manufacturer's recommendations as well as best industry practices in determining the scope and frequency of maintenance on power equipment. Maintenance programs comply with all regulated requirements as prescribed in Section 4.4 of the DSC. In distribution and transformer stations, where applicable, maintenance also meets IESO and NERC requirements and is completed in accordance with associated elements from the Transmission System Code and best practice IEEE guidelines.

While fulfilling its asset management responsibilities, PUC engages in the following type of maintenance programs:

- Maintenance Policy #1: Reactive Maintenance - Occurrences where no planned maintenance is carried out and asset components are repaired or refurbished only after they break down or reach a stage that they fail to perform their intended functions. The follow-up activities to restore the asset to full function are included here. Occasionally the most cost-effective way to remedy the situation is a replacement.
- Maintenance Policy #2: Proactive Maintenance - Condition of an asset's components are assessed periodically through inspections, testing and recent asset performance and maintenance activities are proactively performed to prevent impairment in asset performance with the intent of extending the economic service life of assets

Figure 5.3-49 illustrates the impact of maintenance activities in extending the service life of an asset.

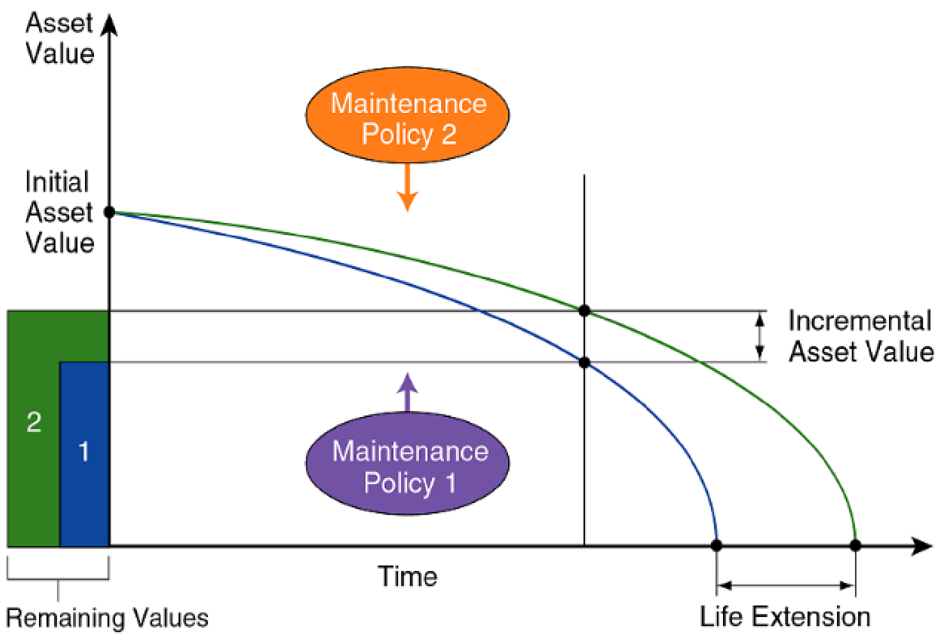


Figure 5.3-49: Risk Based Decision Support System

In Figure 5.3-49, Maintenance Policy 1 represents a reactive maintenance policy, in which no planned maintenance is carried out and asset components are repaired or refurbished only after they break down or reach a stage that they fail to perform their intended functions. Maintenance Policy 2 represents proactive asset maintenance, in which condition of an asset's components are assessed periodically through inspections, testing and recent asset performance and maintenance activities are proactively performed to prevent impairment in asset performance with the intent of extending the economic service life of assets. Under Maintenance Policy 2, Optimization is carried out with the objective of minimizing overall life cycle costs of electricity distribution assets, while meeting the required performance levels, by considering all available information relevant to the condition of assets. As shown in Figure 5.3-49, Maintenance Policy 2 would be economically efficient, so long as the incremental asset value achieved through an assets' life extension is greater than the incremental maintenance cost resulting from Policy 2.

Following this value concept, PUC's maintenance planning criteria is rooted in adopting a maintenance policy that results in lowest life cycle cost for assets. For those assets, where the incremental value obtained in form of extended asset life is greater than the cost of maintenance activities, Policy 2 is adopted. These assets include high value power equipment installed in stations. Periodic inspections at more frequent intervals are performed and maintenance activities are scheduled by considering the condition of assets. For lower value assets, maintenance activities are performed in a reactive mode and the scope of repairs is limited to rectifying deficiencies found during safety inspections. Periodic asset inspections and testing provide valuable information on assets' health and probability of assets' failures, allowing appropriate risk management initiatives to be implemented over the lifecycle of each asset.

As an example, PUC has employed this model as follows for in-situ testing of wood poles. All poles are tested and inspected on a seven-year cycle. Poles that are determined to be in acceptable condition are deemed satisfactory until the next test cycle. Poles that exhibit significant deterioration but are still structurally sound are treated or maintained using boron rods to extend their service life. Poles that are more significantly deteriorated are scheduled for replacement.

PUC's Operations & Maintenance (O&M) programs are designed to follow the guidelines set out in the OEB's Appendix-C DSC for the inspection and maintenance of all key distribution system assets. PUC reviews its O&M programs annually in order to best align with our capital programs and aligning the program with the best industry practices and standards. Inspection and testing of assets is critical for the prioritization of operations and maintenance spending and optimization of the total life cycle asset cost. The results of inspections and testing are used to identify and prioritize system rehabilitation projects, resulting in selection of the optimal decision to either replace, repair or do-nothing. Assets for which replacement is identified as the optimal solution are included in the capital plan for replacement. For assets where replacement during the next five years is not determined to be the optimal solution, PUC's O&M programs include minor repairs and maintenance work designed to economically extend the life of assets. In both cases, planned replacement projects and planned operations and maintenance activities are selected in order to align with the budget envelopes by optimizing the scope and timing of work during project prioritization and selection processes.

5.3.3.2.1 Preventative Maintenance of Critical Equipment in Substation

PUC's planned substation maintenance schedule is summarized in Table 5.3-21.

Table 5.3-21: Substation Preventative Maintenance

	Visual Inspection of Assets	Testing of Insulating Oil Samples, and Infrared Scanning	DC System Maintenance	Full Off-line Substation Maintenance (Annual Cycle Tests)
Distribution Stations	Monthly	Annually	Quarterly	Once in six years
Transformer Stations	Weekly	Annually	Quarterly	Once in four years

Monthly inspections at distribution substations and weekly inspections at transformer stations include the following tasks:

- Inspect substation security (gates locked, fence condition, warning signs and emergency contact information posted).
- Inspect substation yard and building condition, including vegetation growth, snowbank accumulation, garbage, vandalism, etc.

- Inspect substation electrical safety, including fence grounds, bonds, equipment grounds, insulators, foundations, ancillary equipment, metal clad fastenings and corrosion related impairment of assets
- Power Transformer Inspections, including checking and recording oil level, oil temperature, equipment grounds, feeder load readings (Amps)
- Inspect Access and Egress Riser Poles
- Verify AC voltage to Battery Banks
- Inspect Batteries
- Inspect and record Relay Voltage, Amps etc.

The annual cycle maintenance of substation equipment includes thorough inspection, testing and maintenance of all power equipment installed at substations. The substation is taken out of service typically for an extended period to perform maintenance. The station maintenance work includes:

- Oil Testing of Transformers (standard 5-part ASTM and DGA)
- Clean and lubricate switches and fusing
- Conduct Insulation Resistance Testing
- Protection Relays are injection tested to verify settings and ensure operating times adhere to the manufacturer's specifications
- Clean and lubricate switchgear, ensure proper operation
- Conduct IR scans of all high voltage electrical equipment (insulators, switches, cables, connections, and riser poles)
- Oil Testing of Transformers (standard 5-part ASTM and DGA)
- DC System batteries are maintained as per manufacturers specifications on a quarterly basis at all distribution and transformer stations

5.3.3.2.1.1 Vegetation Management Program

PUC's service territory is divided into four sections in order to delineate the areas for the purpose of maintaining safe clearance of trees and branches from distribution system lines and equipment. Vegetation growth around distribution system lines is managed according to our Utility Vegetation Management program on a four-year cycle by attending to each section in succession on a yearly basis.

- Line clearing activities are predominantly completed via a contract that specifies removal of vegetation growth within 3m of primary conductors and 1.5m of secondary conductors. Identification and removal of danger trees, as well as brushing and herbicide treatment of right-of-way where appropriate are included to ensure a comprehensive program.
- Substation herbicide treatment (as required)

During plant inspections, PUC line crews sometimes identify dead or unstable trees that could impact public safety or system reliability. The identified "danger" trees are then removed by PUC line crews or facilitated during the contract period depending on urgency. Although danger tree and customer requested removals are predominantly completed within the scope of an outside contract, PUC line crews will also perform work to maintain safe clearances throughout the year in response to urgent safety or reliability issues or storm damage. All customer requests for tree related issues are tracked as Customer Service Orders through the Customer Information System.

5.3.3.2.1.2 Safety Inspections of Overhead and Underground Distribution Assets

PUC lines and underground distribution system plant are inspected on a three-year cycle, to comply with the requirements outlined in Section 4.4 of the DSC. One third of the distribution assets employed on PUC's supply network are inspected each year. Structural defects, clearance issues and electrical problems and hazards are identified through visual inspections and where problems are revealed, either repair work is scheduled or capital work is planned, as needed. Where the inspections determine an immediate hazard to the public, immediate follow up action is taken to mitigate the problem.

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

A distributor should explain the processes and tools it uses to forecast, prioritize, and optimize system renewal spending and how a distributor intends to operate within budget envelopes. For prioritizing capital expenditures, a distributor should help the reviewer understand the approaches a distributor uses to balance a customer's need for reliability and capital expenditure costs.

The processes and tools used to forecast, prioritize, and optimize system renewal spending and PUC's strategies for operating within budget envelopes are described in the following subsections.

5.3.3.3.1 Forecasting

System renewal projects are discretionary in nature. 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 METSCO for PUC to establish the health and condition of distribution and substation assets in service. By taking into account all relevant information related to assets' operating condition, the condition of all infrastructure assets were assessed and expressed on a normalized index in the form of a Health Index (HI). The HI was related to probability of failure values for each project, using a weighted average approach, as described in detail in Appendix H, 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 was used to help forecast the renewal needs of PUC's assets over the forecast period.

5.3.3.3.2 Prioritization

As previously detailed in Section 5.3.1.3, discretionary system renewal projects are selected and prioritized based on value and risk assessments for each project. Risk consequence related to reliability, safety, operating efficiency, etc. for each project area with assets found in "poor" or "very poor" condition are identified and calculated by multiplying composite probability of asset failure with consequence of failure. Costs for the scope of work to mitigate risk in each project area are determined, using distribution system estimating data.

Through careful evaluation of the risks, projects are prioritized for implementation to mitigate higher level risks during this DSP implementation period, while deferring the projects with lower level risks or risks that can be managed through alternative cost-effective mitigation measures.

For example, although much equipment at both transformer stations serving the entire service territory has been determined to be in poor, or fair and approaching poor condition, due to redundancy in their design, it has been possible to defer the approximately $25 million of the required investments for their rebuild. In the interim, investment in conceptual and preliminary engineering and capital designs are proposed within the timeframe of this DSP. All practical options will be explored through a comprehensive planning and engineering study to identify the optimal station development alternative with highest economic value, for implementation.

In case of the underground distribution system, cables in direct buried configurations present higher risk upon failure in relation to cables installed in duct and therefore have been given higher priority in the cable renewal program and the required investments for renewal of cables in poor condition but installed in duct have been deferred. These cables can generally be run to fail and replaced promptly to minimize associated outage impacts. Funding for this capital requirement is allocated as 'forced renewal' dollars in the plans.

5.3.3.3.3 Optimization

The selected system renewal projects are paced for implementation based on the funding available for asset renewal and by taking into account the resources required for project implementation for the type of work predominantly involved (overhead, underground or substations).

The continued performance of assets is also managed through PUC's capital investments and maintenance programs. PUC's inspection, maintenance, and testing practices described previously in Section 5.3.3.2 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 registers, maintenance and inspection records and outage records are all critical inputs into prioritizing and in optimizing which projects will bring the best value. For example, PUC can use information from its pole testing program, its annual plant inspection program and reliability statistics, all together, to maximize risk reduction while minimizing cost impacts when addressing end of life and failing poles.

5.3.3.3.4 Strategies for Operating within Budget Envelopes

The scope of capital investments planned in the system renewal category has been determined with the objective of keeping power supply reliability from deteriorating below an acceptable level. In order to keep the overall investment envelope for this DSP within a range, which would not result in retail rates escalations beyond the affordability of PUC's customer base and which could be successfully implemented without stretching beyond limit PUC's financial resources; investments required for renewal and rehabilitation of the assets found in "very poor" or "poor" condition have been spread out over a time period of longer than five years and assets with highest consequence of failure in service, have been prioritized for renewal or rehabilitation, during the next five years.

Due to their non-discretionary nature, system access projects will also take priority in the event that there are competing demands with system renewal projects. The use of a regularly updated plan based on the latest information allows this process to be managed in an effective manner with the objective of successfully completing all projects planned for in the DSP.

Maintaining spending within budget envelopes is crucial to maximizing value and minimizing costs for customers. To achieve this, PUC carefully considers all inputs from operations, assets, and all pertinent risks and consequences to the business. A formal ERM (enterprise risk management) process with key risk indicators and risk managers is in place to eliminate threats of foreseeable impacts. Active budget management at all levels and at various frequencies (five year COS plan annual budgets, quarterly divisional progress updates, monthly and weekly front-line meetings) all ensure scope, cost and timeline remain on track at all scales and over all timeframes.

5.3.3.3.5 Risks of Proceeding / Not Proceeding

A distributor should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures

PUC employs the results of visual inspections, in-situ testing and service age of assets to determine the condition of assets by deriving a HI for each asset. The HI is related to the probability of failure for the asset by relating the health of the asset to an effective age and corresponding known failure curve. The probability of failure data is multiplied by the consequences of failure for assets within a project area to arrive at a risk score. Consequences of failure are derived from the analysis of each project area and classification in terms of potential impacts to worker and public safety, the environment, reliability, and operational effectiveness that could arise if a failure event occurs. Once the risk of each project area has been established it is placed into a prioritization and selection process that determines which projects require action and the extent of the action that is necessary to minimize unacceptable risks.

Risk is factored into the selection and prioritization of capital expenditures during the prioritization process. Assets with unacceptably high risk scores are monitored closely and plans are included in project scope to alternatively maintain, refurbish or replace the assets to reduce the risk to an acceptable level. 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 associated with them in relation to 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

A distributor should provide a summary of any important changes to the distributor's asset life optimization policies and processes since the last DSP filing.

No changes have been made to PUC's asset life optimization policies and processes since the last DSP filing.

5.3.4 System Capability Assessment for REG

If a distributor has costs to accommodate and connect renewable generation facilities that will be the responsibility of the distributor under the DSC, and are therefore eligible for recovery through the provincial cost recovery mechanism set out in section 79.1 of the Ontario Energy Board Act, 1998, then a distributor should refer to Appendix A.

A distributor should provide information on the capability of its distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity.

PUC currently has approximately 63MW of REG connected to its distribution system, which on occasion results in net export conditions during summer months when the distribution network is near its minimum load. PUC also hosts an IESO controlled 7MW/7MWh battery energy storage facility.

PUC has prepared and submitted a REG Plan to the IESO, which is included in Appendix F. The associated IESO comment letter in response to the REG Plan is attached in Appendix G.

Due to the SSG project and investments over the past ten years primarily in protection, control, SCADA and communications infrastructure, PUC is well positioned to support a broad range of REG and smart grid initiatives. PUC can also say with confidence that past investments along with currently available capacity will allow the connection of all forecast REG projects for the next five years with no need for additional system investments.

5.3.4.1 Applications for Renewable Generators over 10 kW

Applications from renewable generators over 10 kW for connection in the distributor's service area.

There are presently no current applications for REG generator connections greater than 10 kW for connection in PUC's service area. The connection history for all REG installations connected to the PUC system over 10kW is illustrated in Table 5.3-22 below. Of all the applications made, those that were not connected had applications terminated by the applicant and in no cases was unavailable capacity the deciding factor.

Table 5.3-22: Summary of REG Applications >10kW

Timeline	Application Date	Application MW	Connection Date	Connection MW
Pre - 2013	1985	0.25	1985	0.25
	2008-01-08	0.037	2008-07-08	0.037
	2007-07-24	0.045	2008	0.045
	2007-04-15	9.95	2010-10-15	9.96
	2007-04-17	9.95	2010-10-15	9.96
	2007-06-03	9.95	2011-08-30	9.96
	2007-06-03	9.95	2011-08-30	9.96
	2007-06-03	9.95	2011-07-27	9.96
	2007-06-03	9.95	2011-11-22	9.96
	2007	9.95	N/A	0
	2007	9.95	N/A	0
	2011-09-09	0.035	2012-11-23	0.035
	2011-06-07	0.5	2011-07-20	0.5
	2011-09-26	0.25	2012-08-29	0.25
	2011-02-28	0.1	2011-06-09	0.1
	2011-06-14	0.135	2011-11-14	0.135
	Quantity 16	Total MW 80.952	Quantity	Total MW 61.112
2013	Quantity 0	Total MW 0	Quantity 0	Total Mw 0
2014	Quantity 0	Total MW 0	Quantity 0	Total MW 0
2015	2015-02-18	0.1	2016-08-23	0.1
	Quantity 1	Total MW 0.1	Quantity 1	Total MW 0.1
2016	2016-06-23	0.07	2016-09-20	0.07
	2016-03-11	0.25	2017-01-06	0.25
	2016-03-11	0.25	2017-01-06	0.25
	2016-03-11	0.25	2017-01-06	0.25
	Quantity 4	Total MW 0.82	Quantity 4	Total MW 0.82
2017	Quantity 0	Total MW 0	Quantity 0	Total MW 0
2018	2018-11-23	0.087	N/A	0

Timeline	Application Date		Application MW		Connection Date		Connection MW	
	Quantity	1	Total MW	0.087	Quantity	1	Total MW	0
2019	Quantity	0	Total MW	0	Quantity	0	Total Mw	0
2020	Quantity	0	Total MW	0	Quantity	0	Total Mw	0
2021	Quantity	0	Total MW	0	Quantity	0	Total Mw	0
2017-2021 Totals	Quantity	1	Total MW	0.087	Quantity	1	Total Mw	0
Grand Total	Quantity	17	Total MW	81.039	Quantity	15	Total Mw	61.112

5.3.4.1.1 Applications for REG Generators 10kW or less

Currently there are no applications in the queue from REG connections <10kW. Since the winddown of the Micro-FIT program by the province, there appears to be a growing interest in net metering and some discussions about that in conjunction with energy storage behind the meter, however this has not materialized into any significant connected projects. There has been a total of six net metering <10kW connections totaling 41kW since 2016 and there are currently two connection applications totaling 14kW in progress.

5.3.4.2 Forecast of REG Connections

The number and the capacity (in MW) of renewable generation connections anticipated over the forecast period based on existing connection applications, information available from the IESO and any other information the distributor has about the potential for renewable generation in its service area (where a distributor has a large service area, or two or more non-contiguous regions included in its service area, a regional breakdown must be provided).

PUC has produced a five-year forecast of future REG connections >10kW. For the period 2023-2027 projections have been based on:

- local economic and population data
- macro-economic conditions
- awareness of information from IESO and OEB regarding connection rates and programs
- historical uptake and connection frequency

Based on those factors, the five-year forecast in Table 5.3-23 below has been established with an anticipated connection of one 100kW generator every second year for a total connection of 0.3MW over the next five-year period.

Table 5.3-23: Five-year REG Forecast

Year	Projected # of Connections	Installed MW
2023	1	0.1
2024	0	0
2025	1	0.1
2026	0	0
2027	1	0.1
2023-2027 Totals	3	0.3

The PUC grid is presently very well positioned to support all forecast REG connections over the next five years and no associated infrastructure investment is required during that period.

5.3.4.3 Capacity Available

The capacity (MW) of the distributor's distribution system to connect renewable energy generation located within the distributor's service area.

Table 5.3-24 summarizes available capacity at the 34.5kV feeder and station bus levels, primarily based on thermal ratings of conductors and transformers. At present there is still capacity available for the future connection of approximately 27MW more generation between circuits out of TS-1 and TS-2 combined.

It is noted here that feeders SM-5, 7, 9 and 11 are shown as having only 3.7MW each of remaining capacity however those capacities are based on the limiting factor of the upstream 115kV/35kV transformers at TS-1 which have a combined limit of 45MW. The limit of 45MW less the existing connected 41.3MW REG leaves the possibility of connecting a combined total of 3.7MW in any combination on those four feeders. So, although each of the four feeders have 20MW of available thermal capacity, they are limited by the fact that the station transformer remaining capacity is lower. Based on the projected connections for the next five years, this does not represent a system constraint.

Table 5.3-24: Available System Capacity for Accepting Additional REG Connections

Station	Bus Name	Capacity (MW)	Allocated Capacity (MW)	Available Capacity (MW)	Supply Circuit 1	Supply Circuit 2
TS-1 (St. Mary's)	**Total**	**45**	**41.328**	**3.672**	**GL1SM**	**GL2SM**
	West	30	21.009	3.672		
	East	30	20.318	3.672		
TS-2 (Tarentorus)	**Total**	**45**	**21.663**	**23.337**	**GL1TA**	**GL2TA**
	West	30	21.015	8.985		
	East	30	0.647	23.337		
34.5 kV Feeder Name	**Bus Connection**	**Capacity (MW)**	**Allocated Capacity**	**Available Capacity (MW)**	**Notes:**	
SM-5	West	30	10.214	3.672	TS Limiting (45-D5) MW	
SM-7	West	30	9.960	3.672	TS Limiting (45-D5) MW	
Sub 19 West	West	N/A	0.835	N/A	no feeder, direct bus connection	
SM-9	East	30	10.034	3.672	TS Limiting (45-D5) MW	
SM-11	East	30	10.034	3.672	TS Limiting (45-D5) MW	
Sub 19 East	East	N/A	0.250	N/A	no feeder, direct bus connection	
TS1			**41.328**			
TA-6	West	30	0.139	23.337	TS Limiting (45-D8) MW	
TA-7	West	30	20.876	8.985	West Bus Limiting (30-D9) MW	
TA-9	East	30	0.028	23.337	TS Limiting (45-D8) MW	
TA-10	East	30	0.188	23.337	TS Limiting (45-D8) MW	
TA-11	East	30	0.431	23.337	TS Limiting (45-D8) MW	
TS2			**21.663**			

PUC's own operating experience indicates successful integration of approximately 63MW of REG on its distribution system with winter peak demand of approximately 140MW and summer as low as 80MW.

5.3.4.4 Constraints – Distribution and Upstream

Constraints related to the connection of renewable generation, either within the distributor's system or upstream system (host distributor and/or transmitter).

5.3.4.4.1 Operational Flexibility

Integration of REG has presented some new challenges to maintaining the operational flexibility previously afforded to PUC by a highly looped 34.5kV and 12.47kV system. However, PUC continues to work closely with the generators during the development and connection agreement stages of each project to ensure that both the generator and the LDC find solutions that minimize limitations to operational flexibility.

5.3.4.4.2 Protection, Control and SCADA

The introduction of REG resources introduces the potential for reverse power flow conditions, reduced relay sensitivity to trip during fault conditions, power quality and voltage regulation. Solutions to these problems call for fast and advanced modern microprocessor based, and communications enabled protection, control and SCADA equipment. PUC anticipated these needs amongst others such as reliability and embarked on several initiatives over the past ten years that will benefit REG and smart grid deployments now and in the future:

- A major upgrade of the PUC SCADA core components and implementation of a data historian (2008 – 2011)
- Deployment of an Ethernet based communications backbone over modern fibre-optic and radio platforms to support protection, control, SCADA, telemetry, metering, and enterprise network functions. Support for anticipated forthcoming NERC cybersecurity requirements is built in. (2010-2018)
- Upgrade of protective relaying at TS-1, TS-2 and all 12kV stations not slated for rebuilds or retirement in the next five years to microprocessor based, IP communications-based equipment capable of full REG support (2008 – 2022)
- The SSG Project will bring Volt/VAR optimization to every 12.47kV feeder, as well as automated system restoration and fault isolation, and an upgraded SCADA/OMS system for in depth system analysis

5.3.4.4.3 Regional Infrastructure Planning

As previously noted, PUC belongs to the East Lake Superior Region planning team. As part of the second planning cycle, development of an IRRP and RIP was completed in 2021. PUC participated in the planning process and provided required data to HONI and the IESO. The scope of this planning initiative was to identify critical infrastructure needs of the transmission grid during the next 20 years beginning in 2020. The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans. The report shows a modest decline in load for PUC over the study period and only nominal growth for the region. No constraints or barriers to REG growth for the PUC service territory are anticipated as a result of the regional factors considered.

5.3.4.5 Constraints – Embedded Distributor

Constraints for an embedded distributor that may result from the connections

PUC has no embedded distributors therefore does not contribute to any associated REG constraints.

5.3.5 CDM Activities to Address System Needs

The OEB's 2021 Conservation and Demand Management Guidelines for Electricity Distributors (the CDM Guidelines) require distributors to make reasonable efforts to incorporate consideration of CDM activities (for example, energy efficiency, demand response, or energy storage) into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure. A distributor's DSP should describe how it has taken CDM into consideration in its planning process.

Any application for CDM funding to address system needs must include a consideration of the projected effects to the distribution system on a long-term basis and the forecast expenditures. Distributors must explain the proposed activity in the context of the distributor's DSP or explain any changes to its system plans that are pertinent to the activity. Distributors may apply to the OEB for funding through distribution rates for CDM activities as specified in the CDM Guidelines.

CDM programs aim to reduce electricity consumption as a means of managing system costs, reducing peak demand and improving the affordability of electricity bills for customers. Over the historical period, CDM initiatives implemented by PUC's residential and general service customers, such as the Affordability Fund Trust (AFT) program, has resulted in a modest decline in the peak demand on the electrical grid, has reduced electricity bills for customers, and has helped improve overall customer satisfaction. However, the decline in peak demand due to CDM initiatives alone has not historically been substantial enough to warrant any major avoided or deferred infrastructure investments.

As noted in Section 5.2.2.5, PUC has ongoing consultations with its customers, consultants, other distributors and the IESO to effectively promote and deliver CDM programs. PUC also considers the applicability of CDM as part of Step 1 of its AM process (i.e., Needs Assessment) to determine whether CDM is a feasible option to meet the identified system need (see Section 5.3.1.3 for further detail). In accordance with IESO's 2021-2024 CDM Framework and other IESO materials including the Planning Outlook, PUC has also made an adjustment to its load forecast to account for IESO's CDM activities (additional details are included in Exhibit 4, Section 3.1.4 and Appendix I).

One of the main benefits of the SSG Project are the expected energy savings associated with the VVO technology. Since this technology will be used to reduce energy consumption, it can be considered as a type of CDM activity. Although these energy savings will deliver direct benefits to customers and reduce provincial energy and demand requirements, they are not expected to be substantial enough to avoid or defer infrastructure investments over the forecast period.

Other than the energy savings associated with the SSG Project, PUC is not currently planning to offer any new CDM programs or activities to its customers, and PUC has not identified any opportunities to avoid or defer infrastructure investments as a result of CDM activities over the forecast period.

5.3.6 The Sault Smart Grid Project

5.3.6.1 Project Overview

The Sault Smart Grid Project (SSG Project) is a community wide smart grid which will cover PUC's entire service territory. The key components of the SSG Project are a new ADMS and OMS, which will include the following functionality:

- Voltage/VAR Optimization (VVO): allows a utility to operate its distribution system at the lower end of the acceptable voltage ranges and reduces reactive power in the distribution system resulting in lower system losses, lower energy consumption, and an overall system energy and demand reduction.
- Distribution Automation (DA): provides better monitoring and control of the distribution system by providing real time data as well as the capabilities to remotely locate faults and remotely operate equipment to restore service in the event of fault or loss of upstream power.
- Advanced Metering Infrastructure (AMI): allows a utility to leverage its AMI data for better data analytics and reporting. For the purposes of the SSG Project, a new application for AMI will be realized through leveraged AMI data as a key source for volt/VAR management and optimization. Selected bellwether meters provide voltage data for feedback to the distribution management software algorithm that allows a lower and optimized voltage to reduce energy consumption.

The SSG Project will transform PUC's entire distribution system through an integrated project implementing the technologies and functionalities noted above. The SSG Project was approved as part of a separate ICM application.

5.3.6.2 OEB Decision and Order

The SSG Project ICM was approved by the OEB. The Orders set out in OEB Decision and Order EB-2020-0249/EB-2018-0219 dated April 29, 2021, are summarized in Table 5.3-25 below.

Table 5.3-25: SSG Project ICM - OEB Orders

#	OEB Order	PUC Response
1	The Ontario Energy Board approves the amended and restated Incremental Capital Module (ICM) application filed by PUC Inc. for new rates effective May 1, 2022, subject to the conditions set out below.	No response / action required.
2	The Accounting Order set out in Schedule A of this Decision and Order is approved.	No response / action required.
3	PUC Inc. shall file its next rebasing application for 2023 rates no later than August 31, 2022.	Completed
4	PUC Inc. shall file an updated Distribution System Plan at the time of its next rebasing application which demonstrates how the SSG Project is being accommodated through the re-prioritization of other capital expenditures	See Section 5.3.6.2.1
5	PUC Inc. shall provide a detailed report as part of its next rebasing application, which compares the SSG Project costs and benefits as implemented to what was forecast in this application.	See Section 5.3.6.2.2
6	PUC Inc. shall file all available information on the proposed Project performance metrics that it intends to track, along with proposed targets, in its next rebasing application. This shall include an appropriate metric and targets to symmetrically link the VVO performance of the Project to PUC Inc.'s allowable ROE for this Project.	See Section 5.3.6.2.3
7	PUC Inc. shall post on its public website a report, within 18 months of Project completion, and with annual updates for 10 years thereafter which shows the actual benefits of the SSG Project, broken down by customer class.	This action will be completed within 18 months of project completion.

#	OEB Order	PUC Response
8	PUC shall include the approved ICM rate riders on its proposed tariff for its 2022 rate application.	Completed
9	Any EPC Contract liquidated damages resulting from “performance” or “delay” shall be used to reduce the Project capital cost and would be settled at the time of the next rebasing.	See Section 5.3.6.2.4

5.3.6.2.1 PUC’s Response to OEB Order #4

When PUC made the decision to develop and implement the innovative SSG Project in its service territory, it was understood that PUC would have to revisit and adjust its capital investment plan and priorities to accommodate and better align with the SSG Project.

The SSG Project priority was determined using PUC’s established prioritization process (previously described in Section 5.3.1.3), and the result was compared against PUC’s other planned activities. The SSG Project priority ranking was based on the following criteria:

- Public Safety Impact: This criterion was not a driving priority for the SSG Project as the public safety impacts associated with the SSG Project are expected to be neutral. However, PUC notes that the SSG Project technologies have been selected and engineered with safety in mind, and the project will be constructed and operated while adhering to all applicable safety regulations and standards.
- Outage Customer Impact: The SSG Project includes adaptive infrastructure which improves reliability and resiliency with self-healing networks and integrated data management systems for normal outage planning and situational weather events with enhanced outage management capability. Since all PUC customers will benefit from these reliability improvements, this was a driving factor for the prioritization of the SSG Project.
- Customer Value for Dollars Spent: All PUC customers will derive value from this project.
- System Service Improvements: This project will transform PUC’s distribution system by integrating technologies that allows for voltage optimization, monitoring of the distribution system, and leveraging real time data. This will improve PUC’s system reliability and operational effectiveness, while positioning PUC for future growth and grid modernization. This was another driving factor for the prioritization of the SSG Project.
- Project Interdependence: Some synergies have been identified between system renewal expenditures and the SSG Project, including the renewal of station transformers and switchgear in support of both renewal and SSG Project needs. However, project interdependence is a longer term factor that is expected to come into play once the project is used and useful. The system and data availability will support PUC’s decision making to make better long-term asset management decisions and forecasting capital requirements.

In 2021, after approval of the SSG Project was granted, PUC executed contingency plans that re-adjusted the priority of other activities to better align with SSG Project. As noted in PUC’s last DSP, PUC had originally planned to implement a substation rebuild project in 2020-2022 (Substation 22) for approximately $3.5 million. However, when re-evaluating its capital plans, PUC concluded that the Substation 22 rebuild project could be deferred to 2026-2027 so that funds can be re-prioritized to accommodate the SSG Project. The deferral of Substation 22 was substituted with the renewal of six transformers and primary switchgear at three of PUC’s existing distribution stations (Subs 2, 11 and 20) that were identified as having warranted asset renewal needs. This resulted in overall renewal cost savings due to the synergies leveraged through achieving both aged asset renewal with reduced future requirements for stations investment and the NRCan funding eligibility benefits of the SSG Project. Additionally, On-Load Tap Changers were added to a scheduled rebuild project at Substation 16 to benefit the VVO feature of the SSG Project in 2021. As a result, a total of $3.5 million from the Substation 22 rebuild project is being re-allocated to support the SSG Project.

As a result of the ongoing funds and resource requirements associated with the SSG Project, additional project deferral decisions have been recently made by PUC to better accommodate the SSG Project. One example is the decision to defer PUC's proposed GIS UN Migration project from a 2023/24 implementation timeframe to a 2024/25 implementation timeframe.

5.3.6.2.2 PUC's Response to OEB Order #5

The SSG Project is expected to be used and useful by the end of 2022, with a small portion of testing and optimization set to occur in the first quarter of 2023 to maximize project benefits. Since the SSG Project is still underway the costs and benefits realized are not yet finalized, however updates to the project costs and expected benefits, based on the latest information available, are provided below. Upon the SSG Project completion, PUC will prepare a detailed report comparing the SSG Project costs and benefits as implement to what was forecast in the ICM Application, and the update provided in this COS Application.

<u>Project Cost Comparison</u>

On April 29, 2021, the OEB approved the amended ICM Application filed by PUC on October 28, 2020, for new rates effective May 1, 2022 (as part of proceeding EB-2018-0219/EB-2020-0249). At that time, PUC was approved to collect a half year revenue requirement of $875,610 based on a gross capital project spend of $32,938,213 and NRCan contributions of $8,109,553, for a net total of $24,828,660 (referred to below as the "Approved Submission" numbers).

After PUC was approved for its SSG Project ICM Application, the total amount of federal NRCan funding was not the same as when PUC originally submitted its application. The total amount of NRCan grants available to PUC was reduced by $754,115 in 2022, and therefore the amount available to PUC for NRCan funding was reduced proportionately. PUC adjusted the scope of the DA and the gross project spend to $31,903,718, corresponding to a reduction of $1,034,495. Revisions to the gross project spend and NRCan contributions resulted in a revised net total spend to $24,548,280 (referred to below as the "Revised Total Project Spend" numbers).

The Revised Total Project Spend numbers are further broken down into 2022 and 2023 capital additions, with the bulk of the project spending occurring in 2022 and a relatively minor portion occurring in the first quarter of 2023 for testing and optimization. PUC is expecting to incur $21.36M or 87% of the total net project cost in 2022, with the remaining 13%, or $3.19M being incurred in 2023. Although $3.19M of the SSG Project net spend has been reallocated to the 2023 Test Year, the SSG Project spend has been pre-approved as part of the EB-2020-0249/EB-2018-0219 ICM application and is not considered to be part of PUC's normal capital expenditures.

As shown in Table 5.3-26, the updated revenue requirement associated with the project is now $868,713, corresponding to a reduction of $6,897. PUC has calculated the revised revenue requirement using the ICM Model submitted in the ICM Application. PUC projects to collect $852,614 using the load forecast as billing determinant for May 1, 2022, to April 30, 2023.

Table 5.3-26: Sault Smart Grid ICM Reconciliation

	Approved Submission[1]	Revised Total Project Spend			Variance
		2022 Capital Additions (ICM)	2023 Capital Additions (COS)	Total	
Gross Capital	$32,938,213	$28,713,347	$3,190,371	$31,903,718	($1,034,495)
NRCan Contribution	$8,109,553	$7,355,438	$-	$7,355,438	($754,115)
Net Capital	$24,828,660	$21,357,909	$3,190,371	$24,548,280	($280,380)
Used and Useful Date	31-Dec-22	31-Dec-22	31-Mar-23[2]		
	Revenue Requirement				**Variance**
Revenue Requirement	$875,610	$868,713			($6,897)
Projected Rate Rider Revenue		$852,614			
Refund or Collection		$16,100			

Note 1 – These numbers correspond to the updated numbers provided in PUC's response to OEB Staff-5 as part of proceeding EB-2018-0219/EB-2020-0249 (filed January 25, 2021). These numbers were approved by the OEB in their Decision and Order dated April 29, 2021.
Note 2 – The SSG Project is expected to be used and useful by the end of 2022. Only testing and optimization is required in the first quarter of Q1 2023 to maximize project benefits.

Customer Annual Net Benefit Comparison

In the SSG Project ICM application, PUC noted that the SSG Project was expected to achieve an annual net benefit to customers of $616,897. An updated calculation is provided in Table 5.3-27 below. Variances are due to a significant decrease in the cost of power (COP) by over $13.2M. This is due to a reduced load forecast as presented in Exhibit 3 of the COS Application. Additionally with the cost of power decrease comes less savings in projected system loss energy. The last variance is due to an increase in revenue requirement of $598. This increase is from a change in asset category classification of capital assets that make up the entire SSG Project value (i.e., the revised classification into OEB Account 1820 Distribution Station Equipment has more useful life than originally calculated).

Table 5.3-27: Customer Annual Net Benefit Summary Comparison

	28-Oct-2020 Submission	2023 Update	Variance
Cost of Power - updated to current estimate (not including GS>50 on 34.5kV)	$82,512,685	$69,302,488	($13,210,197)
Projected energy savings with SSG implementation	2.70%	2.70%	2.70%
Projected customer energy savings through SSG	$2,227,842	$ 1,871,167	($356,675)
Projected system loss energy savings through SSG	$105,111	$79,664	($25,447)
Total purchased power savings	$2,332,953	$1,950,831	($382,122)

	28-Oct-2020 Submission	2023 Update	Variance
Additional revenue from increased SSG asset base	$1,754,862	$1,755,460	$598
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	$0
Additional O & M expenses due to SSG implementation	$296,400	$296,400	$0
Operating efficiency benefits due to SSG implementation	($30,816)	($30,816)	$0
Change In Revenue Requirement	$1,716,056	$1,716,654	$598
Annual net benefit to customers	**$616,897**	**$234,177**	**($382,720)**
Annual projected reliability benefit to customers	$2,017,000	$2,017,000	$0
Total projected benefit to customers	$2,633,897	$2,303,734	($382,720)

An updated sensitivity analysis of net benefit calculations is provided in Table 5.3-28 below. The major variance is due to the decrease in cost of power as a new baseline to the cost of power in 2023 and future years.

Table 5.3-28: Sensitivity Analysis of Net Benefits Calculations (NPV 2022-2041) Comparison

	Low Scenario (2% energy savings)	Base Scenario (2.7% energy savings)	High Scenario (4% energy savings)
NPV of Annual net benefit to customers			
28-Oct-2020 Submission (SEC 12 IRR)	$3,729,534	$12,506,291	$28,805,983
2023 Update	$1,949,477	$10,218,024	$27,574,196
Variance	($1,780,057)	($2,288,267)	($3,596,786)
NPV of projected reliability benefits			
28-Oct-2020 Submission (SEC 12 IRR)	$25,864,956	$25,864,956	$25,864,956
2023 Update	$25,864,956	$25,864,956	$25,864,956
Variance	$ -	$ -	$ -

<u>Other Project Benefits</u>

An update on the anticipated benefits of the SSG Project as compared to what was forecast in the ICM application is summarized below:

- **Energy Savings:** The initial engineering developed for the ICM application identified an estimate of achievable energy savings of 2.7%. The fundamental factors and assumptions of this estimate have not changed during the work leading up to the current construction for the project, so the estimate remains at 2.7%. Ultimately execution of the measurement methodology and processes following the new VVO solutions being fully in service will determine the results achieved.
- **Reliability Improvement & Feeder Priority:** Detailed engineering analysis was completed analyzing three years of outage data for circuit reliability performance. Metrics were developed

using metrics found in IEEE 1806[6] and several scenarios were developed. Additional metrics were applied in context of PUC circuit load and customer data to these scenarios. Each scenario developed a feeder ranking for inclusion in project scope and costing. Ultimately feeder investment, feeder priority criteria, and realizable reliability benefits were scaled to project scope and budget commitments.

- **Long Term CAPEX Savings with SSG Integration to the DSP:** Synergies between system renewal investments with respect to station renewal arising from ACA recommendations and the technology applications for the SSG project provided opportunity to save the investment in voltage regulation assets for the SSG project in some selected locations and replace with investment in replacing aged station assets with integrated load tap change capability. Incrementally the LTC transformer solution is higher now, ~ $400k per unit compared to the station pad-mounted voltage regulator, but this saves the future cost of the transformer replacement in subsequent DSP station renewal planning.
- **OEB Scorecard Metrics:** On page 47 of PUC's resubmission of its ICM application for the SSG Project (EB-2018-0170/EB-2020-0249) on October 28, 2020, PUC discussed the benefits the project will have on the four main performance outcomes of the regulatory scorecard (Customer Focus, Operational Effectiveness; Public Policy Responsiveness and Financial Performance). Additional details on this can be found in Section 5.2.3.3 above.

5.3.6.2.3 PUC's Response to OEB Order #6

PUC has engaged an SSG contractor to develop the methodology, in collaboration with PUC, for calculating the SSG Project performance metrics as outlined in PUC's ICM Application (EB-2018-0219/EB-2020-0249). PUC will file the methodology and targets for each category as soon as it becomes available.

<u>VVO Link to ROE</u>

As a requirement of the decision for EB-2018-0219/2020-0249, PUC has developed a methodology to symmetrically link VVO savings to ROE by using a new deferral and variance account as proposed in the Accounting Order attached to Exhibit 9, Appendix B. The following steps, as outlined in Table 5.3-29, details the methodology PUC will use to calculate the revised net benefit to customers based on actual annual consumption savings and actual year COP.

Table 5.3-29: Customer Net Benefit Summary

	Top of Dead Band	Bottom of Dead Band	Scenario 1	Scenario 2	Scenario 3	Scenario4
Measured (estimate) VVO Consumption Savings	16,324,838	14,327,652	13,350,394	16,822,310	782,551	29,750,110
PUC Annual Consumption	604, 623,538	606,565,655	607,598,147	603,161,981	603,161,981	603,161,981
PUC Consumption without SSG (projection from LF)	620,948,376	620,893,307	620,948,541	619,984,291	603,944,531	632,912,091
% Savings	2.70%	2.36%	2.20%	2.79%	0.13%	4.93%
PUC Cost of Power Paid	$69,302,488	$69,302,488	$69,302,488	$69,302,488	$69,302,488	$69,302,488

[6] IEEE Guide for Reliability-Based Placement of Overhead and Underground Switching and Overcurrent Protection Equipment up to and Including 38 kV – IEEE Std 1806-2021.

	Top of Dead Band	Bottom of Dead Band	Scenario 1	Scenario 2	Scenario 3	Scenario4
Average $/kWh	0.1146	0.1143	0.1141	0.1149	0.1149	0.1149
PUC Cost of Power Paid without SSG consumption savings	$71,173,655	$70,939,478	$70,825,230	$71,235,348	$69,392,402	$72,720,735
Customer Energy Savings	$1,871,167	$1,636,990	$1,522,742	$1,932,860	$89,914	$3,418,247
Dollar Savings from Loss Factor consumption reduction	$79,664	$79,664	$79,664	$79,664	$79,664	$79,664
Total purchased power savings	**$1,950,831**	**$1,716,654**	**$1,602,406**	**$2,012,524**	**$169,578**	**$3,497,911**
Additional revenue from increased SSG asset base	$1,755,460	$1,755,460	$1,755,460	$1,755,460	$1,755,460	$1,755,460
Benefit of reduced capital expenditures with SSG	($304,390)	($304,390)	($304,389)	($304,388)	($304,388)	($304,388)
Additional O&M expenses due to SSG implementation	$296,400	$296,400	$296,400	$296,400	$296,400	$296,400
Operating efficiency benefits due to SSG implementation	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)
Change In Revenue Requirement	$1,716,654	$1,716,654	$1,716,655	$1,716,656	$1,716,656	$1,716,656
Annual net benefit to customers	**$234,177**	**$ 0**	**($114,249)**	**$295,868**	**($1,547,078)**	**$1,781,255**

First, PUC will measure VVO consumption (kWh) savings on an annual basis. The methodology for calculating VVO savings is being developed in collaboration with PUC's SSG contractor which will be used as an input. The very top line of Table 5.3-29 shows assumption of what that input might be for the purposes of this calculation and the VVO linkage to ROE. These consumption savings are added back to PUC's actual total consumption in each year to determine the resulting VVO savings as a percentage. This is shown in the top four rows of Table 5.3-29 above. Next, the actual cost of power paid each year is divided by the actual consumption to obtain and average cost per kWh. This average cost per kWh is multiplied by PUC's consumption without VVO savings to get the COP customer would have paid in absence of the VVO savings.

The methodology then must adjust for PUC's loss factor. As such, the calculation compares the approved loss factor to PUC's actual loss factor. As outlined in PUC's SSG Project ICM Application (EB-2018-0219/2020-0249) in Appendix AA14, it was noted that a reduction in loss factor would occur as a result of the SSG project. PUC will use Appendix AA14 yearly to input the additional dollar savings from loss factor.

The final step is to review the revenue requirement calculation for SSG included in rates. The benefit of reduced future capital expenditures, as described in EB-208-0219/2020-0249 is $234,177 in each year moving forward. Additional O&M expenses of $296,400 and operating efficiency savings of $30,816 are also factored in, resulting in a total cost to customers (through rates).

The calculated energy savings from VVO in the first step is compared to the calculated costs through revenue requirement of the SSG Project. The difference is the net benefit/(disadvantage) to customers.

Considering that the COP will fluctuate on a yearly basis, PUC proposes a band where the breakeven point, (i.e., $0 savings to customers) as a percentage is the low end of the band, with the upper limit being 2.70% or $234,177 VVO savings.

This methodology is illustrated in Table 5.3-29, with the second column showing the VVO savings target of 2.70%, the high end of the dead band, and the third column showing the lower end of dead band (i.e., customer breakeven) at 2.36% VVO savings. This ensures customers will receive a no net bill increase.

Only when the VVO consumption savings in a year are outside of the established dead band (2.36% to 2.70%), is a DVA entry triggered. Below the dead band, incremental costs to rate payers are shared 50/50 between ratepayers and PUC. Above the dead band, incremental savings to ratepayers are shared 50/50 between ratepayers and PUC. Scenario 1 shows a VVO savings of 2.20%, which results in incremental costs to customer of $114,249. PUC proposes to share 50/50 in those costs, causing a credit of $57,124 to the new DVA account. Scenario 2 shows a VVO savings of 2.79%, which results in incremental savings to customers of $295,868. The dollar value of VVO savings at the top end of the dead band ($234,177) is subtracted from this, resulting in $61,692 that is shared 50/50 with ratepayers and PUC. This creates a debit entry to the new DVA account for $30,846. Table 5.3-30 below shows the accounting entries for the DVA account for scenarios 1-4 in Table 5.3-29 above.

Table 5.3-30: Accounting Entries for the DVA in Example Scenarios

Journal Entry						
	Top of Dead Band	**Bottom of Dead Band**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
4080 Distribution Revenue			$57,124		$773,539	
1508 Other Regulatory Assets, Sub-Account Incremental SSG Costs			$57,124		$773,539	
to record the reduction in savings to PUC customers.						
1508 Other Regulatory Assets, Sub-Account Incremental SSG Savings				$30,846		$773,539
4080 Distribution Revenue				$30,846		$773,539
to record the reduction in savings to PUC customers.						
VVO Linkage to ROE						
	Top of Dead Band	**Bottom of Dead Band**	**Scenario 1**	**Scenario 2**	**Scenario 3**	**Scenario 4**
2023 Board Approved Rate Base	$136,089,187	$136,089,187	$136,089,187	$136,089,187	$136,089,187	$136,089,187
2023 Board Approved Net Income	$4,714,129	$4,714,129	$4,714,129	$4,714,129	$4,714,129	$4,714,129
2023 VVO linked Net Income	$4,714,129	$4,714,129	$4,657,005	$4,744,975	$3,940,590	$5,487,668
2023 Board Approved ROE	8.66%	8.66%	8.66%	8.66%	8.66%	8.66%
2023 VVO linked ROE	8.66%	8.66%	8.56%	8.72%	7.24%	10.08%
Reduction in ROE	0.00%	0.00%	-0.10%	0.06%	-1.42%	1.42%

Additionally, PUC is proposing a symmetrical maximum upside and downside equal to the ROE of the SSG assets. Based on the revised project spend in Table 5.3-26 and the OEB's current cost of capital parameters, the current cap is ± $773,539. Scenario 3 shows VVO savings of 0.13%, which would result in incremental customer costs of $1,547,078. This is the maximum amount PUC is proposing to share incremental costs in and therefore results in a DVA credit entry of $773,539. Scenario 4 shows VVO savings of 4.93%, which would result in customer savings of $1,781,255. Again, the top end of the dead band of $234,177 is subtracted to get $1,547,078 in savings that PUC will share 50/50 with customers, creating a debit entry to the DVA account for $773,539.

5.3.6.2.4 PUC's Response to OEB Order #9

At this current stage, PUC does not expect any EPC Contract liquidated damages. However, if liquidated damages were to materialize in 2023, a revised revenue requirement calculation will be completed, and the difference will be recorded in a newly created DVA account. The accounting order for this DVA account is provided in Exhibit 9, Appendix C.

5.4 CAPITAL EXPENDITURE PLAN

The capital expenditure plan should set out and comprehensively justify a distributor's proposed expenditures on its distribution system and general plant over a five-year planning period, including investment and asset-related operating and maintenance expenditures.

A distributor's DSP details the system investment decisions developed on the basis of information derived from its planning process. It is critical that investments be justified in whole or in part by reference to specific aspects of that process. As noted in section 5.2 above, a DSP must include information on the historical and forecast period.

This section summarizes PUC's capital expenditure plan, which has been developed to meet PUC'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 purpose of the information filed under this section is to provide a snapshot of a distributor's capital expenditures over a 10-year period, including five historical years and five forecast years. Despite the multi-purpose character a project or program may have, for summary purposes the entire cost of individual projects or programs are to be allocated to one of the four investment categories on the basis of the primary (i.e., initial or trigger) driver of the investment. For material projects/programs, a distributor must estimate and allocate costs to the relevant investment categories when providing information to justify the investment, as this assists in understanding the relationship between the costs and benefits attributable to each driver underlying the investment. In any event, the categorization of an individual project or program for the purposes of these filing requirements should not in any way affect the proper apportionment of project costs as per the DSC. The distributor must provide completed appendices 2-AA and 2-AB.

The capital expenditure summary provides a snapshot of PUC's capital and System O&M expenditures over the 2018 – 2027 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 PUC'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.

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

Category	Historical												Bridge Year		
	2018			2019			2020			2021			2022		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Bgt.	Var.
	$ ‘000		%	$ ‘000		%	$ ‘000		%	$ ‘000		%	$ ‘000		%
System Access															
Gross Capital Spend	1,541	1,890	23%	2,043	2,475	21%	2,552	2,364	(7%)	2,052	2,154	5%	2,035	1,836	(10%)
Capital Contributions	(450)	(483)	7%	(428)	(883)	106%	(465)	(421)	(9%)	(448)	(442)	(1%)	(475)	(456)	(4%)
Net Capital Expenditures	1,091	1,406	29%	1,615	1,592	(1%)	2,086	1,942	(7%)	1,604	1,712	7%	1,560	1,380	(12%)
System Renewal															
Gross Capital Spend	3,761	3,599	(4%)	7,357	3,172	(57%)	3,328	3,397	2%	4,565	8,918	95%	7,129	6,629	(7%)
Capital Contributions	-	52	100%	(31)	(229)	647%	(31)	(237)	660%	(32)	(144)	353%	(37)	(37)	1%
Net Capital Expenditures	3,761	3,651	(3%)	7,326	2,943	(60%)	3,296	3,160	(4%)	4,533	8,774	94%	7,093	6,593	(7%)
System Service															
Gross Capital Spend	-	73	100%	-	-	--	-	-	--	-	154	100%	-	28,713	100%
Capital Contributions	-	-	--	-	-	--	-	-	--	-	-	--	-	(7,355)	100%
Net Capital Expenditures	-	73	100%	-	-	--	-	-	--	-	154	100%	-	21,358	100%
General Plant															
Gross Capital Spend	86	14	(84%)	55	188	244%	62	124	100%	60	593	891%	55	-	(100%)
Capital Contributions	-	-	--	-	-	--	-	-	--	-	-	--	-	-	-
Net Capital Expenditures	86	14	(84%)	55	188	244%	62	124	100%	60	593	891%	55	-	(100%)
Total Expenditure, Gross	**5,388**	**5,576**	**3%**	**9,454**	**5,835**	**(38%)**	**5,941**	**5,884**	**(1%)**	**6,676**	**11,819**	**77%**	**9,219**	**37,178**	**303%**
Total Capital Contribution	**(450)**	**(431)**	**(4%)**	**(458)**	**(1112)**	**143%**	**(496)**	**(658)**	**33%**	**(480)**	**(586)**	**22%**	**(511)**	**(7,848)**	**1,435%**
Total Expenditure, Net	**4,938**	**5,145**	**4%**	**8,996**	**4,724**	**(47%)**	**5,445**	**5,226**	**(4%)**	**6,197**	**11,234**	**81%**	**8,708**	**29,330**	**237%**
System O&M	6,300	6,010	(5%)	6,306	6,302	(0%)	6,400	6,434	1%	6,496	6,407	(1%)	6,680	6,680	0%

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

Category	Forecast				
	2023	2024	2025	2026	2027
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access					
Gross Capital Spend	2,339	2,672	2,792	2,494	2,357
Capital Contributions	(555)	(577)	(602)	(571)	(582)
Net Capital Expenditures	1,784	2,095	2,190	1,923	1,775
System Renewal					
Gross Capital Spend	4,599	4,240	3,442	3,548	2,567
Capital Contributions	(38)	(39)	(40)	(41)	(42)
Net Capital Expenditures	4,561	4,200	3,402	3,507	2,525
System Service					
Gross Capital Spend	3,190	127	841	750	5,859
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	3,190	127	841	750	5,859
General Plant					
Gross Capital Spend	577	813	1,033	432	633
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	577	813	1,033	432	633
Total Expenditure, Gross	**10,705**	**7,853**	**8,109**	**7,224**	**11,416**
Total Capital Contribution	**(593)**	**(616)**	**(642)**	**(612)**	**(624)**
Total Expenditure, Net	**10,113**	**7,236**	**7,467**	**6,612**	**10,792**
System O&M	7,280	7,644	8,026	8,428	8,849

5.4.1.1 Plan vs Actual Variances for the Historical Period

The distributor must provide an analysis of a distributor's capital expenditure performance for the DSP's historical period. This should include an explanation of variances by investment or category, including that of actuals versus the OEB-approved amounts for the applicant's last OEB-approved CoS or Custom IR application and DSP. A distributor should particularly explain variances in a given year that are much higher or lower than the historical trend.

Assessing and understanding the variances is an important step for PUC to promote continuous improvements in its estimation and budgeting process. Excluding projects identified as mandatory, PUC 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 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. These projects are mostly unplanned and tracked in real-time to balance the total annual budget with other discretionary projects (i.e., PUC 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, PUC may plan to allocate the budget to other system access planning years or to other project categories where appropriate to maintain consistent annual expenditures.

The breakdowns below are provided by each category for each year. Variances that exceed +/- 10% are explained and are in reference to Table 5.4-1.

Table 5.4-3: Variance Explanations – 2018 Planned Versus Actuals

Category	2018			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Access, Net	1,091	1,406	29%	System access spending in 2018 was higher than budget due to the impacts of two externally driven projects that were not known to PUC at the time of budgeting. The largest contribution to the variance was due to the city's Black Road widening project that proceeded sooner than originally planned in response to availability of funding grants to the City for the project. This widening required the relocation and rebuild of adjacent PUC overhead circuits. The second contributor was the need to do joint use make-ready to support a city wide Bell Fibre to the Home (FTTH) project. Although both of these projects presented some increase to capital spending required in system access for 2018, they did come with benefits of accelerating some infrastructure renewal and a portion of that renewal was recoverable from the requesting customers due to the applicable cost sharing agreements.
System Renewal, Net	3,761	3,651	(3%)	Minor variance
System Service, Net	-	73	100%	PUC did not project any system service spending in 2018, however actual spending amounted to $73k. This is due to costs associated with construction of a 34.5 kV tie feeder link that was built to transfer load between PUC's two main transformer stations. This was an unplanned project but was necessary to allow

Category	2018			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
				a transfer of load between the two transformer stations to permit some critical repairs and maintenance to occur at the transformer stations. This was necessitated by the fact that the switches at the transformer stations that would normally be used to provide isolation for work protection are no longer functional. As a result, the only way to establish a safe work zone was to transfer the load and take a complete outage
General Plant, Net	86	14	(84%)	In 2018, general plant actual spending was 84% lower than the planned amount of $86k. This was due to the deferral of a few small facilities renewal projects to 2019 and 2020.
Total Expenditure, Net	4,938	5,145	4%	Minor variance.
Capital Contributions	(450)	(431)	(4%)	Minor variance.
Total Expenditure, Gross	5,388	5,576	3%	Minor variance.
System O&M	6,300	6,010	(5%)	Minor variance.

Table 5.4-4: Variance Explanations – 2019 Planned Versus Actuals

Category	2019			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Access, Net	1,615	1,592	(1%)	Minor variance.
System Renewal, Net	7,326	2,943	(60%)	In 2019, system renewal projects actual spending was 60% lower than the planned amount. This was due to deferral of the Substation 16 rebuild which was originally planned for 2019/2020 but was shifted to 2020/2021, primarily due to the risks of starting construction on a major rebuild project during the COVID 19 pandemic.
System Service, Net	-	-	--	No variance.
General Plant, Net	55	188	244%	In 2019, general plant actual spending was 244% higher than the planned amount due to completion of work completed from 2018 deferrals.
Total Expenditure, Net	8,996	4,724	(47%)	As noted above, the overall net variance is primarily driven by the deferral of Substation 16.
Capital Contributions	(458)	(1112)	143%	The variance in capital contributions for 2019 is almost exclusively due to joint use make ready contributions received from Bell associated with their city wide FTTH project that ran through 2018 and 2019. Although internal resourcing to support this project was a considerable challenge through 2019, it came with a benefit financially in that it allowed for the external funding and acceleration of some asset renewal.
Total Expenditure, Gross	9,454	5,835	(38%)	The variance in total gross expenditure is primarily attributable to the deferral of Substation 16 discussed in the system renewal category above.
System O&M	6,306	6,302	(0%)	Minor variance.

Table 5.4-5: Variance Explanations – 2020 Planned Versus Actuals

Category	2020			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Access, Net	2,086	1,942	(7%)	Minor variance.
System Renewal, Net	3,296	3,160	(4%)	Minor variance.
System Service, Net	-	-	--	No variance.
General Plant, Net	62	124	100%	In 2020, general plant actual spending was 100% higher than the planned amount due to a combination of two factors. Firstly, costs were incurred for completion of some smaller building project deferred from 2018. Secondly, some initial costs for an unplanned project to address safety with garage rollup doors was incurred, as discussed in more detail the 2021 variance analysis for general plant.
Total Expenditure, Net	5,445	5,226	(4%)	Minor variance.
Capital Contributions	(496)	(658)	33%	The elevated capital contributions in 2020 are a continuation of those discussed in the 2018 and 2019 variance analysis, associated with the Bell FTTH project.
Total Expenditure, Gross	5,941	5,884	(1%)	Minor variance.
System O&M	6,400	6,434	1%	Minor variance.

Table 5.4-6: Variance Explanations – 2021 Planned Versus Actuals

Category	2021			Variance Explanations
	Plan.	Act.	Var.	
	$ '000		%	
System Access, Net	1,604	1,712	7%	Minor variance.
System Renewal, Net	4,533	8,774	94%	In 2021, system renewal projects actual spending was 94% higher than planned primarily due to the shift in timing of the Substation 16 project noted above for 2019.
System Service, Net	-	154	100%	PUC did not project any system service spending in 2021, however actual spending amounted to $154k. This was due to costs associated with establishing the 12.47 kV right of way (ROW) along a key rural line to Prince Lake Road. The current ROW was suitable for single phase, but the anticipated future needs are for three phase.
General Plant, Net	60	593	891%	In 2021, general plant actual spending was 891% or approximately $530k higher than the planned amount. This significant overspend was the result of needing to address a safety issue with the main automated roll-up doors in PUC's fleet garage. These were identified as a high risk to worker safety after an incident in 2020 where the mechanism on one of the doors failed and free-fell just missing a line truck passing through.
Total Expenditure, Net	6,197	11,234	81%	As noted above, the overall net variance is primarily driven by the shift in timing of Substation 16.

Category	2021 Plan. ($ '000)	2021 Act. ($ '000)	2021 Var. (%)	Variance Explanations
Capital Contributions	(480)	(586)	22%	the slightly elevated capital contributions in 2021 are primarily associated with contributions from subdivision developers who have been advancing development at a pace higher than initially projected during budgeting.
Total Expenditure, Gross	6,676	11,819	77%	The variance of 77% on total capital expenditures is primarily attributable to the construction of Substation 16, referenced in the system renewal category.
System O&M	6,496	6,407	(1%)	Minor variance.

Table 5.4-7: Variance Explanations – 2022 Planned Versus Budget

Category	2022 Plan. ($ '000)	2022 Bgt. ($ '000)	2022 Var. (%)	Variance Explanations
System Access, Net	1,560	1,380	(12%)	The budgeted amount for system access in 2022 was projected to be approximately 12% lower than the planned amount, however updated indicators for the balance of the year are that customer demand will remain strong as customers make up for lost activity with respect to services and connections during the COVID-19 pandemic.
System Renewal, Net	7,093	6,593	(7%)	Minor variance.
System Service, Net	-	21,358	100%	PUC did not project any system service spending in 2022, however actual spending amounted to $21.358M. This was due to costs associated with the SSG Project.
General Plant, Net	55	-	(100%)	PUC projected to spend $55k in general plant expenditures in 2022, however the updated budget amount for 2022 does not include any general plant expenditures since the needs in this area were deemed to be minimal for 2022. Updated actuals at the end of the year are expected to be at or below the originally planned amount.
Total Expenditure, Net	8,708	29,330	237%	As noted above, the primary driver for the observed increase is the SSG Project.
Capital Contributions	(511)	(7,848)	1,435%	The significant increase in capital contributions in 2022 is due to the NRCan contributions received for the SSG Project.
Total Expenditure, Gross	9,219	37,178	303%	The primary driver for the observed increase is the SSG Project.
System O&M	6,680	6,680	0%	Minor variance.

5.4.1.2 Forecast Expenditures

The distributor must provide an analysis of a distributor's capital expenditures for the DSP's forecast period.

The following table and figure summarize PUC's planned capital expenditures, by investment category, over the forecast period. This is inclusive of the $3.19M SSG Project cost that has been reallocated from 2022 to 2023 (categorized below as a system service investment).

Table 5.4-8: Forecast Net Expenditures 2023-2027 [Incl. SSG Project]

Category	Forecast					Total ($ '000)	Percent of Total
	2023	2024	2025	2026	2027		
	$ '000	$ '000	$ '000	$ '000	$ '000		
System Access	1,784	2,095	2,190	1,923	1,775	9,767	23%
System Renewal	4,561	4,200	3,402	3,507	2,525	18,195	43%
System Service	3,190	127	841	750	5,859	10,767	26%
General Plant	577	813	1,033	432	633	3,488	8%
Total (Net)[1]	**10,113**	**7,236**	**7,467**	**6,612**	**10,792**	**42,217**	**100%**

Note 1- Totals may not add up due to rounding.

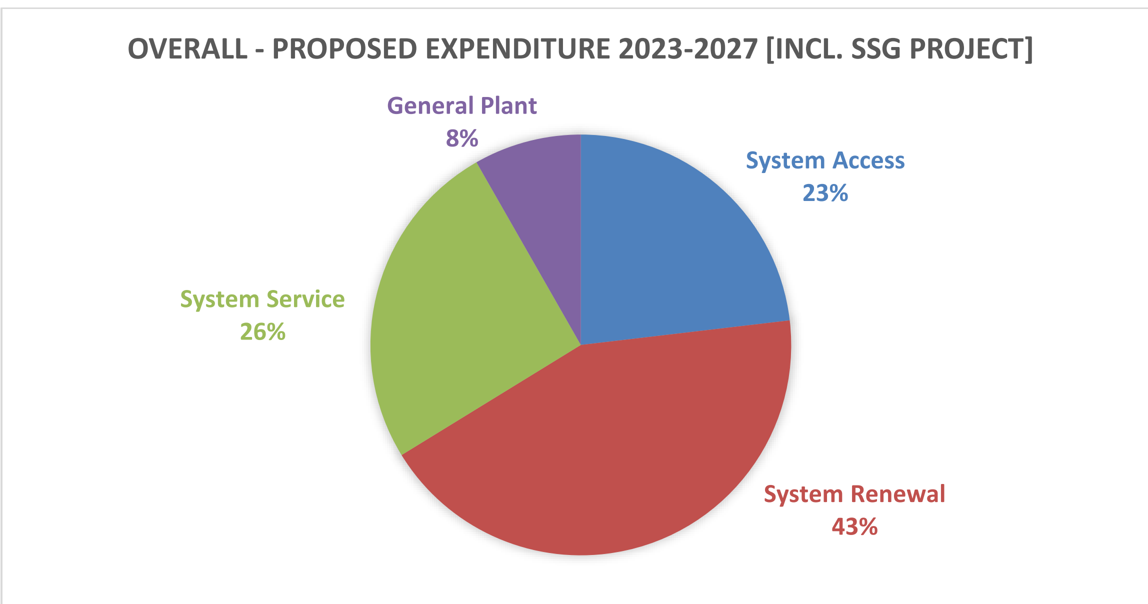


Figure 5. 4-1: Forecast Net Capital Expenditures Ratio [Incl. SSG Project]

When including the SSG Project cost in 2023, system renewal is the largest planned capital expenditure over the 2023-2027 forecast period representing 43% of overall spending, which is followed by system service investments at 26%, then system access and general plant expenditures at 23% and 8%, respectively.

Although $3.19M of the SSG Project net spend has been reallocated to the 2023 Test Year, the SSG Project spend has been pre-approved as part of the EB-2020-0249/EB-2018-0219 ICM application and is not considered to be part of PUC's normal capital expenditures. As a result, PUC has excluded the SSG Project costs from certain analyses in the following subsections to provide the OEB and interveners with a more realistic picture of PUC's historical and forecast expenditures. This also allows for a more representative comparison of the forecast expenditure compared to historical expenditures.

When excluding the SSG Project cost, system renewal remains as the largest portion of the overall planned capital expenditure at 47%, however this is now followed by system access at 25%, system service at 19%, and general plant at 9%, as shown in the following table and figure. The following sub-sections describe the planned capital expenditures in each investment category in more detail.

Table 5.4-9: Forecast Net Expenditures 2023-2027 [Excl. SSG Project]

Category	Forecast					Total ($ '000)	Percent of Total
	2023	2024	2025	2026	2027		
	$ '000	$ '000	$ '000	$ '000	$ '000		
System Access	1,784	2,095	2,190	1,923	1,775	9,767	25%
System Renewal	4,561	4,200	3,402	3,507	2,525	18,195	47%
System Service	0	127	841	750	5,859	7,578	19%
General Plant	577	813	1,033	432	633	3,488	9%
Total (Net)[1]	**6,923**	**7,236**	**7,467**	**6,612**	**10,792**	**39,030**	**100%**

Note 1- Totals may not add up due to rounding.

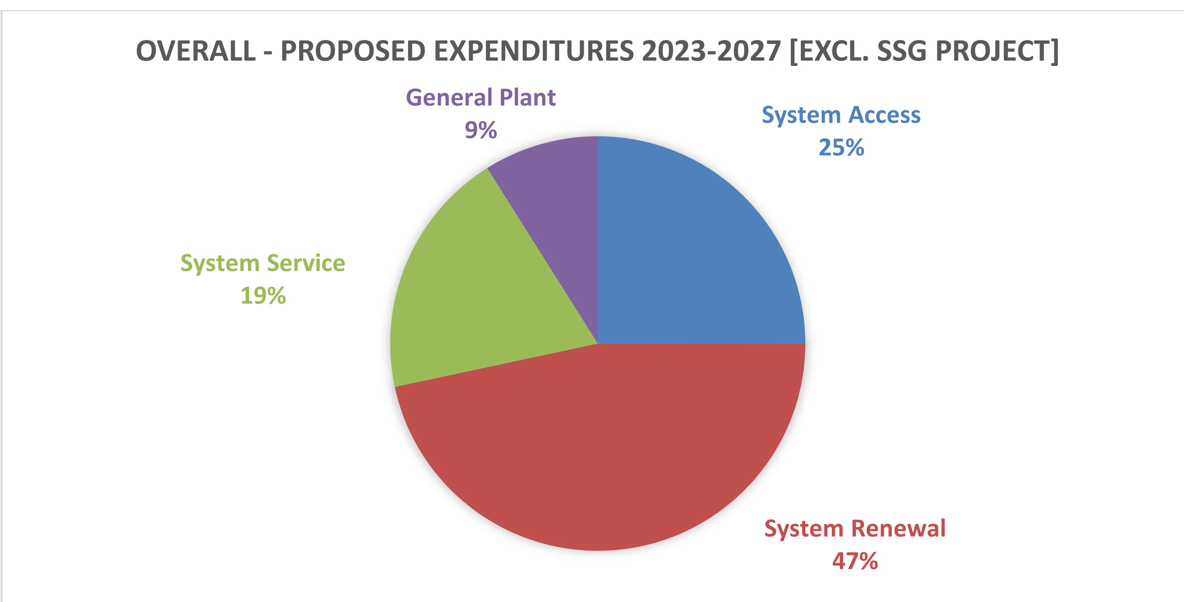


Figure 5.4-1: Forecast Net Capital Expenditures Ratio [Excl. SSG Project]

5.4.1.2.1 System Access

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 investments in this category are driven by the needs of external parties and are considered mandatory. Investments in system access are captured in the following table and figure.

Table 5.4-10: Forecast Net System Access Expenditures

Category	Forecast					Total ($ '000)	Percent of Total
	2023	2024	2025	2026	2027		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Customer Demand - Services	924	929	944	1,007	909	4,714	48%
Customer Demand - New Subdivisions	301	304	309	328	299	1,541	16%
Customer Demand - Joint Use	171	171	174	93	83	692	7%
Customer Demand - City Projects	201	202	257	273	249	1,183	12%
Revenue Meters	187	488	506	222	233	1,636	17%
Total Expenditure, Net	**1,784**	**2,095**	**2,190**	**1,923**	**1,775**	**9,767**	**100%**

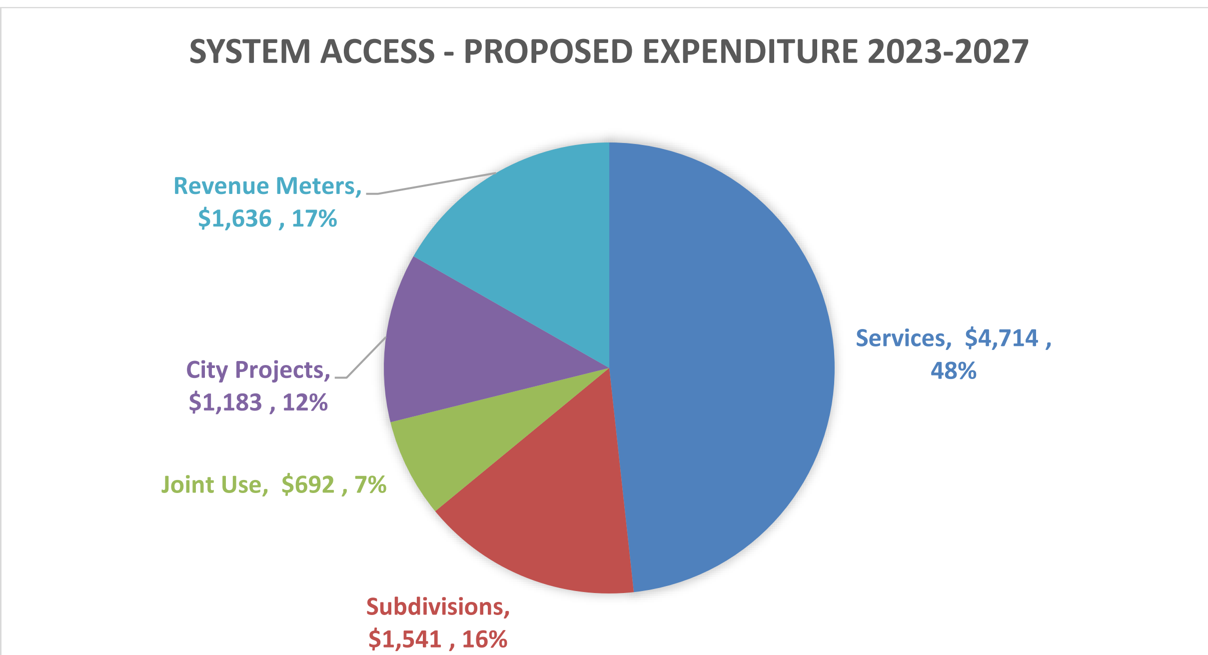


Figure 5.4-2: Forecast Net System Access Expenditures Ratio

Net system access investments represent 23% of PUC's overall budgeted net capital expenditures over the forecast period (or 25% when excluding the SSG Project costs). The proposed expenditure level is estimated based on the historic spending levels and specific information available about planned projects at the time of preparation of this DSP.

Representing the largest portion (48%) of the expenditures within this category, Services involve fulfilling customer requests for new services or upgrade of existing services. Since there is no projected growth in PUC's service territory over the forecast period, services are projected to levelized over the forecast period but will continue to grow in accordance with inflation.

Revenue meters, which represents the second largest driver within this category (17%), is related to the supply, installation and maintenance of revenue meters installed at each customer service point for retail settlement and billing purposes for all customers connected to PUC's distribution system. The observed increase in years 2024 and 2025 is driven by the requirement to install Metering Inside the Settlement Timeframe (MIST) meters for PUC's general service customers that have a monthly average peak demand during a calendar year of over 50 kW (i.e., GS > 50 kW).

At 16%, Subdivisions represents the next largest driver within this category. Subdivisions involves servicing lots to accommodate new subdivisions. Similar to Services, Subdivisions are projected to levelized over the forecast period, but costs will continue to grow in accordance with inflation.

The remaining expenditures are split amongst City Projects (12%) and Joint Use projects (7%). City Projects involves overhead and/or underground lines relocations to accommodate road widening projects and are based on the City of Sault Ste. Marie's 5-year plans. Joint Use projects involve make ready work to facilitate joint use of distribution infrastructure by third parties. Joint Use projects are projected to increase between 2023-2025 to accommodate the government initiatives to increase broadband coverage in rural areas but are expected to return to standard values afterwards.

The level of actual investments for system access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of stakeholder requests received for services, but such deviations are expected to be minor and the overall expenditure level during the next five years is not expected to be significantly different from what is proposed in this DSP.

5.4.1.2.2 System Renewal

System renewal investments involve replacing and/or refurbishing system assets to extend the original service life of the assets and thereby maintain the ability of PUC's distribution system to provide customers with electricity services. As outlined in Section 5.3.1.3, a key input into determining its system renewal projects is the ACA results. These results are a key starting point for PUC to use to determine which investments are required over the DSP period. Where an HI has been created and meets the DAI threshold, the asset information is automatically fed into the planning process. Where PUC identify other assets may require investment, that either don't have a HI available or have a DAI below the threshold, PUC gathers further information before determining if it requires investment. Typically, any asset(s) that is HI4 (Poor) or HI5 (Very Poor) are automatically considered for investment. To be clear, PUC does not automatically take all HI4 and HI5 assets and put them straight into its investment plan. As outlined earlier, various other factors are taken into consideration as well. Investments in system renewal are captured in the following table and figure.

Table 5.4-11: Forecast Net System Renewal Expenditures

Category	Forecast 2023 $ '000	Forecast 2024 $ '000	Forecast 2025 $ '000	Forecast 2026 $ '000	Forecast 2027 $ '000	Total ($ '000)	Percent of Total
Overhead (OH) Distribution System Renewal							
Voltage Conversion	864	-	-	-	-	864	5%
Poles	602	611	621	655	611	3,100	17%
Restricted Conductor	362	1,288	517	834	-	3,000	16%
General Asset Renewal	172	175	178	188	175	888	5%
Transformers (PCBs)	711	722	734	-	-	2,167	12%
Unplanned OH Renewal (forced)	276	279	284	300	277	1,416	8%
Underground (UG) Distribution System Renewal							
UG Cable Replacement - Direct Buried	-	-	-	290	271	560	3%
Pad Mounted Switchgear Renewal	-	115	58	61	57	291	2%
Vaults	401	89	91	95	89	766	4%
General Asset Renewal	31	32	32	34	32	161	1%
Unplanned UG Renewal (forced)	376	382	388	409	382	1,938	11%
Distribution Station Renewal							
Unplanned Distribution Station Asset Renewal (forced)	75	76	78	82	76	388	2%
Building & Fence Repairs	144	115	97	102	96	554	3%
Distribution Station Transformation	38	38	39	20	-	135	1%
Switchgear, Protection, & Control Renewals	176	178	181	191	178	904	5%
SCADA and Communications Asset Renewal	13	13	13	14	13	65	0%
Battery and Charger Replacement	44	-	-	-	51	95	1%
Transformer Station Renewal							
Unplanned Transformer Station Assets Renewal (forced)	75	76	78	82	76	388	2%
Building and Fence Repairs	13	13	13	14	13	65	0%
Transformer Station Transformation	63	-	-	-	-	63	0%
SCADA and Communications Asset Renewal	25	-	-	-	-	25	0%
Battery and Charger Replacement	100	-	-	-	-	100	1%
Planned - TS Rebuild (Engineering)	-	-	-	136	127	264	1%
Total Expenditure, Net	**4,561**	**4,200**	**3,402**	**3,507**	**2,525**	**18,195**	**100%**

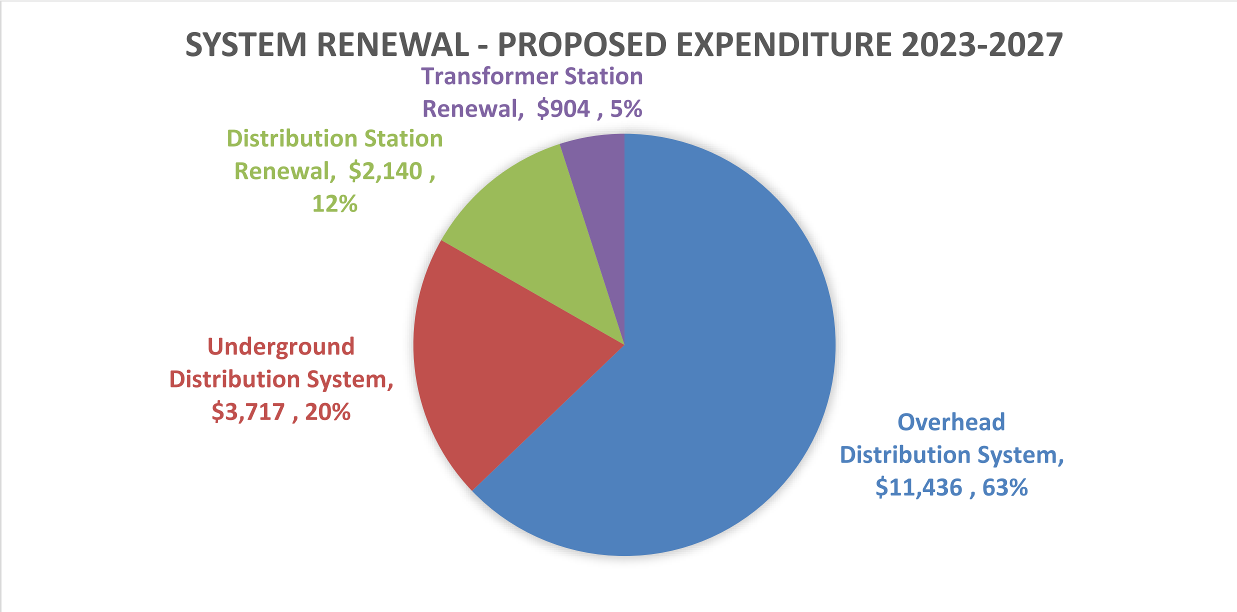


Figure 5.4-3: Forecast Net System Renewal Expenditures Ratio

At 43% (or 47% when excluding the SSG Project costs), system renewal investments represent the largest portion of PUC's overall budgeted net capital expenditures over the forecast period.

Representing the largest portion (63%) of the expenditures within this category, Overhead Distribution System involves the renewal of overhead assets. Major projects within this category includes the proactive renewal of deteriorated poles, the replacement of PCB-contaminated pole mounted transformers, voltage conversions, restricted conductor replacements and other small unplanned projects over the forecast period that are not considered emergency repairs. This also includes the renewal of failed assets on overhead lines.

Representing the second largest portion (20%) of the expenditures within this category, Underground Distribution System involves the renewal of underground assets. Major projects within this category includes the proactive rejuvenation of underground vaults and manholes that have been identified as deficient, replacement of direct buried cable with high failure rates, and the renewal of failed assets on the underground distribution system.

The remaining expenditures are split amongst Distribution Station Renewal (12%) and Transformer Station Renewal (5%), both of which involve the renewal of station assets. Key Distribution Station Renewal projects include the renewal of station switchgear, protection & control assets at select distribution stations as well as building and fence repairs. Transformer Station Renewal projects includes emergency asset repairs upon failure, station battery and charger renewals, and a TS rebuild proposed in 2026-2027.

The level of investments required over the forecast period was determined using PUC's AM process, which is described in detail in Section 5.3 It is noted that priority of investment has been given to assets where strong ACA data is available such as deteriorated poles, distribution transformers and restricted conductor. For assets where ACA data was limited, such as underground cables, station riser cables and distribution and transmission station assets, only smaller investments are proposed for critical assets, and further studies and testing are included in the next five year plan to better quantify the investment needs in these areas. Some specific initiatives planned in the next five years to address these gaps are the establishment of a formal buildings and facilities asset management plan, a transmission station study to determine a course of action for stations TS-1 & TS-2, and expenditure allotted to partial discharge testing of critical direct buried, radial feed cables. PUC will continue to further review its testing and data gaps and put in place additional plans to address these gaps as required.

The year over year fluctuations and overall decrease in system renewal spending over the forecast period is partly driven by the completion of some of PUC's key system renewal investments including the voltage conversion program in 2023 and the replacement of distribution transformers with PCB >50ppm in 2025. The observed decrease is also partially driven by the need to accommodate and balance the increased level of investments required under other investment categories (i.e., System Service). Year over year fluctuations are also impacted by the availability of resources and contractors.

5.4.1.2.3 System Service

System service investments are modifications to PUC's distribution system to ensure the distribution system continues to meet PUC operational objectives (system efficiency, power quality etc.) while addressing anticipated future customer electricity service requirements. Investments in system renewal are captured in the following table and figure.

Table 5.4-12: Forecast Net System Service Expenditures [Incl. SSG Project]

Category	Forecast					Total ($ '000)	Percent of Total
	2023	2024	2025	2026	2027		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Capability – DX Station Build	-	-	324	409	4,904	5,637	52%
Expansions – 34.5 kV OH Lines	-	-	518	341	955	1,814	17%
Expansions – 34.5 kV UG Lines	-	127	-	-	-	127	1%
SSG Project	3,190	-	-	-	-	3,190	30%
Total Expenditure, Net	**3,190**	**127**	**841**	**750**	**5,859**	**10,768**	**100%**

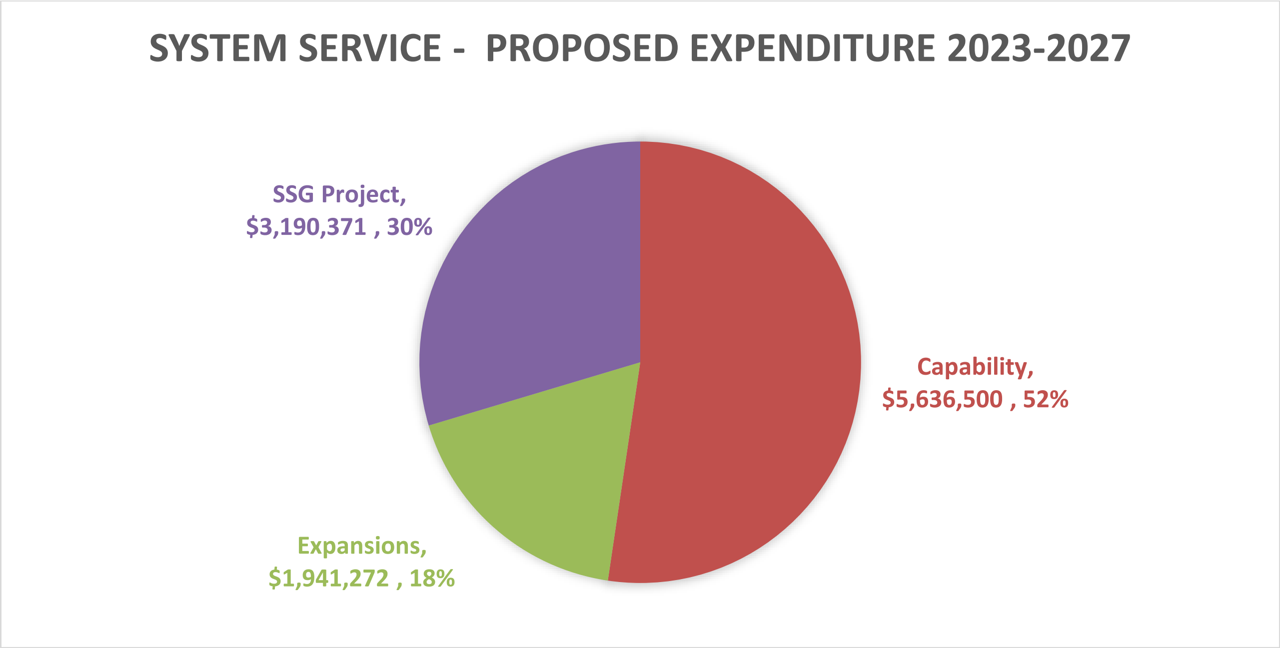


Figure 5.4-2: Forecast Net System Service Expenditures Ratio [Incl. SSG Project]

When including the SSG Project, system service investments represent 26% of PUC's overall budgeted net capital expenditures over the forecast period. Within this category, 52% of the expenditures are associated with Capability, 30% are associated with the SSG Project, and the remaining 18% is associated with Expansions.

The capability costs relate to a new distribution station build (Substation 22 due to be built in 2027) that is proposed to accommodate the localized shift in demand occurring in the westerly portion of PUC's service territory which is being driven by requests for connection of several large and medium sized commercial customers. Additional information on this investment can be found in Section 5.2.1.4.

The costs associated with OH and UG expansions are attributable to costs to construct a new 34.5 kV express feeder tie between PUC's two 115kV/34.5kV transformer stations TS-1 and TS-2. The ability to transfer load between these two critical transformer stations is currently limited. The project will help reduce the potential impacts of a TS component failure and allow the transfer of load promptly during a failure event. As mentioned elsewhere in this application and in the ACA, TS-1 and TS-2 are expected to approach a critical point for replacement in the next five to 15 years and a plan for renewal withing that time horizon is being pursued. The proposed 34.5 kV express feeders will serve as a reliability bridge to see customers through until the larger proposed TS renewal becomes cost effective.

When excluding the SSG Project costs, the ratio of system service expenditures decreases to 19% of overall budgeted net capital expenditures over the forecast period, and approximately two thirds of the expenditures within this category are associated with capability, with the remaining third towards OH and UG expansions, as shown in Figure 5.4-4.

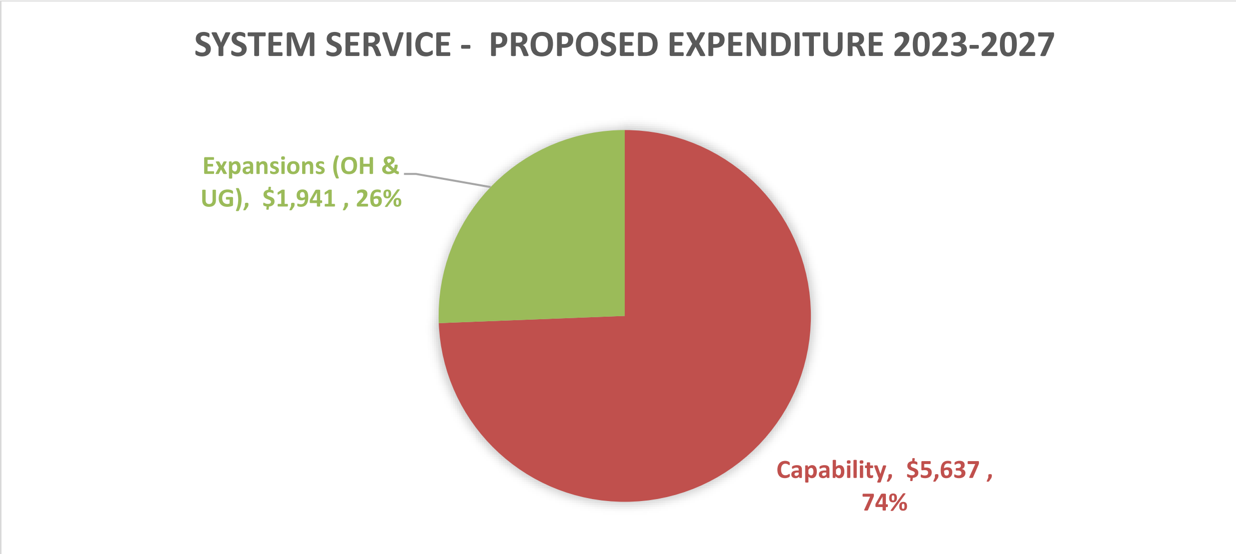


Figure 5.4-4: Forecast Net System Service Expenditures Ratio [Excl. SSG Project]

5.4.1.2.4 General Plant

General plant investments are modifications, replacements, or additions to PUC's assets that are not part of the distribution system; including land and buildings; tools and equipment; rolling stock; and electronic devices and software used to support day-to-day business and operations activities. Investments in general plant are captured in the following table and figure.

Table 5.4-13: Forecast Net General Plant Expenditures

Category	Forecast					Total ($ '000)	Percent of Total
	2023	2024	2025	2026	2027		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Tools & Equipment	295	38	188	-	-	521	15%
Distribution IT	44	483	580	71	41	1,219	35%
Buildings	238	293	265	361	592	1,750	50%
Total Expenditure, Net	**577**	**813**	**1,033**	**432**	**633**	**3,489**	**100%**

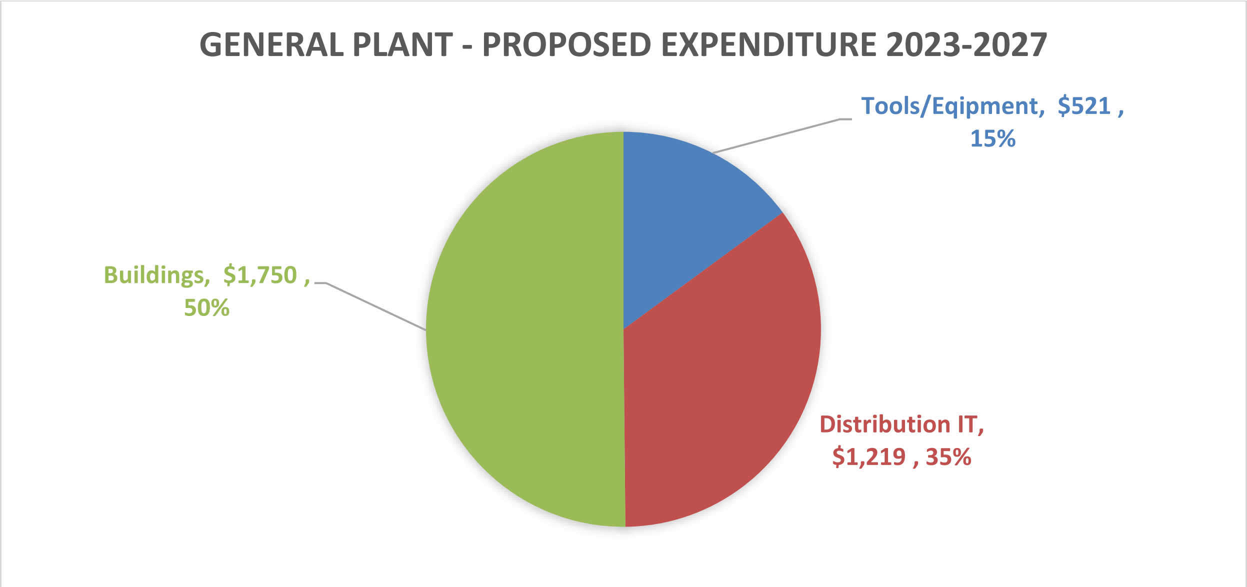


Figure 5.4-5: Forecast Net General Plant Expenditures Ratio

General plant investments represent 8% of PUC's overall budgeted net capital expenditures over the forecast period (or 9% when excluding the SSG Project costs). Representing the largest portion (50%) of the expenditures within this category, Buildings involve the renewal and upkeep of PUC's main facility, which represents the critical backbone of PUC's 24/7 operations. Ongoing Building investments are proposed over the forecast period to ensure safe and reliable continuation of PUC's operations.

Distribution IT, which represents the second largest driver within this category at 35%, is primarily driven by PUC's GIS Utility Network (UN) Migration project planned for 2024/25. PUC's existing GIS is based on Geometric Network technology, which is approximately twenty-five years old, approaching end of useful life, and will no longer be supported by the vendor in the next three years as they move exclusively to a UN platform. Migration to the new platform, including all of PUC's existing asset information and custom developed applications is expected to take two years. Additional information on the GIS UN Migration project can be found in Section 5.4.2.1.1.

The remaining 15% of expenditures in this category is allocated towards tools/equipment, which involves planned investments in tools/equipment to help improve PUC's testing and inspection regimes.

The year over year fluctuations observed in forecast general plant spending are primarily being driven by the SSG Project. The SSG Project timing and resource requirements have resulted in the deferral of the GIS UN Migration project to a 2024/25 implementation timeframe, which explains the overall increase in general plant spending during these years. Following completion of the GIS UN Migration project, PUC expects the Distribution IT spending to return to traditional levels of spending. The other more minor fluctuations observed under tools/equipment and buildings are driven by one-time costs associated with the replacement of larger and more expensive equipment (i.e., oil drying unit and compressor/chiller pump replacements).

5.4.1.2.5 Investments with Project Lifecycle Greater than One Year

For capital investments that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress.

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.

Two examples of multi-year capital projects proposed over the forecast period include the GIS UN Migration project and the new distribution station build (Sub 22). In each 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

An analysis of capital expenditures in the DSP's forecast period as compared to the historical period.

A comparison of PUC's net capital expenditures over the forecast period as compared to the historical period is provided in the following sub-sections.

5.4.1.3.1 System Access

The historical system access trend is variable year over year due to the unpredictability of customer connection service requests and other external factors. As shown in Figure 5.4-6, PUC's system access forecast average expenditures are approximately 22% greater than the historical plus bridge year average. This proposed increase is attributable to two factors. Firstly, in 2022, PUC began experiencing a ramping up of residential and commercial development in the community not seen in over a decade. Through consultations with the City, developers, consultant and contractors, PUC has updated their projections for the forecast period to reflect that this trend which is expected to continue for the next three to five years. Secondly, slightly elevated activity in the area of joint use projects is expected, as the provincial government moves forward with initiatives to expand broadband access across the province.

Historically, an increasing trend in system access costs is observed from 2018 to 2020, followed by a declining trend from year 2020 to year 2022. This is explained by a combination of two factors. Firstly, there was a surge in the area of joint use activity 2018 through 2020 as one of the major telecom utilities in the service territory implemented their 'fibre to the home' initiative. The increase in spending was primarily attributable to the make-ready work associated with this project. This investment, however contributed to renewal of infrastructure that was approaching end of life and did so with partial capital contributions in accordance with joint use agreements, bringing added benefit for ratepayers. The subsequent decline in expenditures in 2021 and 2022 is reflective of the return to more typical historical levels, somewhat dampened by a slowdown in customer connections due to the COVID-19 pandemic.

The temporary increase in forecast costs observed between 2023-2025 can be attributed to the required costs associated with Joint Use projects and MIST meter installations. However, following the completion of these projects, system access costs are expected to return to more standard costs adjusted for inflation.

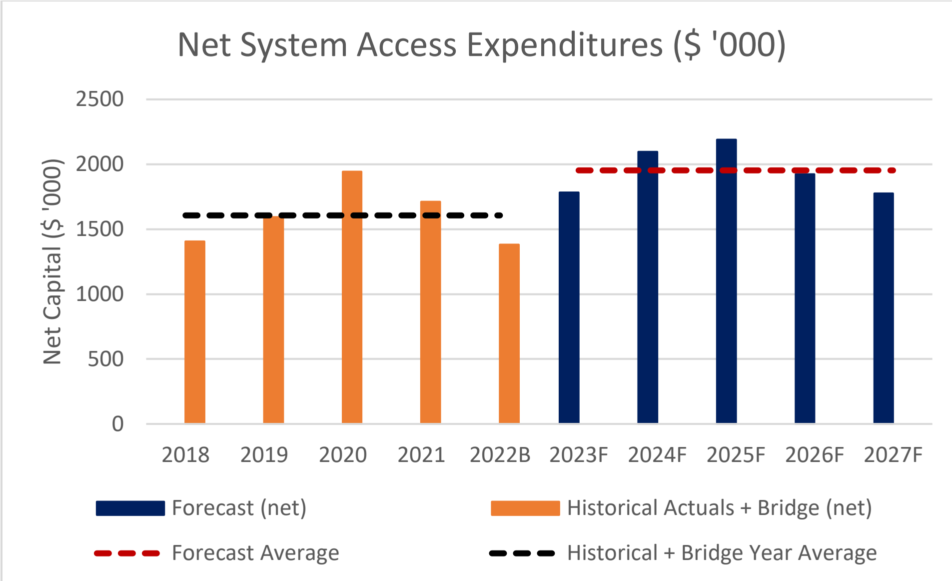


Figure 5.4-6: System Access Comparative Expenditures

5.4.1.3.2 System Renewal

As shown in Figure 5.4-7, PUC's forecast average for system renewal is 28% lower than the historical plus bridge year average. This is primarily as a result of the significant historical spending associated with the following projects:

- The large jump in 2021 is due to the $6.02M spend associated with PUC's Substation 16 ICM (EB-2019-0170). The actual cost for implementation of this project ($6.02M) was above the amount approved at the time of the ICM application ($4.73M) due to inflation in material and labour costs available at the time of construction.
- The jump in 2022 is primarily driven by a $2.7M spend associated with the renewal of six distribution station transformers and primary switchgear at three of PUC's substations that were purchased in support of the SSG Project. Although these investments were not originally planned for 2022, they were identified as having warranted asset renewal needs and received higher priority as a result of their alignment with the SSG Project.

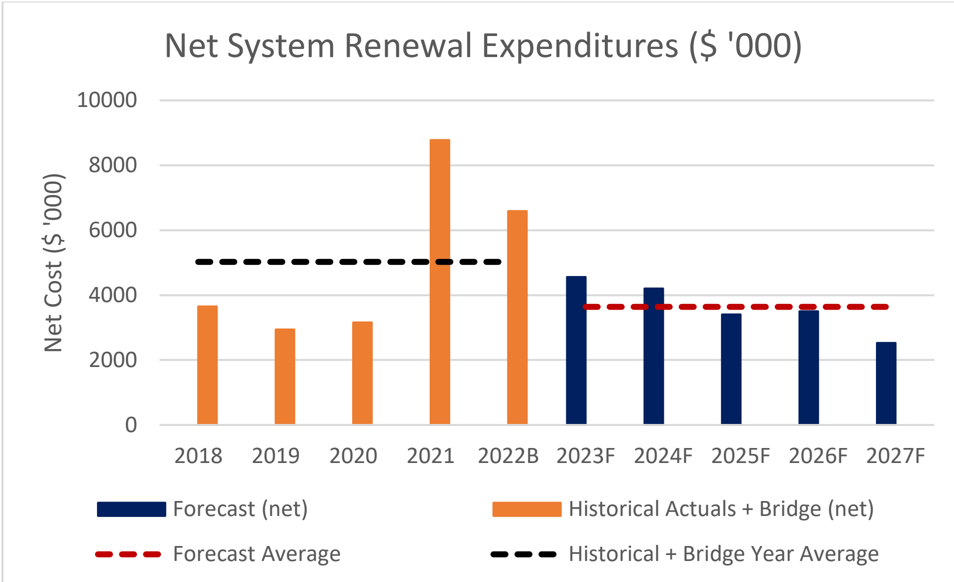


Figure 5.4-7: System Renewal Comparative Expenditures [Incl. Sub 16 ICM]

The timing and magnitude of Substation 16 was not finalized at the time of the previous COS filing, and an ICM application was required and approved by the OEB. When excluding the costs associated with PUC's Substation 16 ICM project, the forecast average for system renewal is 5% lower than the historical plus bridge year average, as shown in Figure 5.4-8.

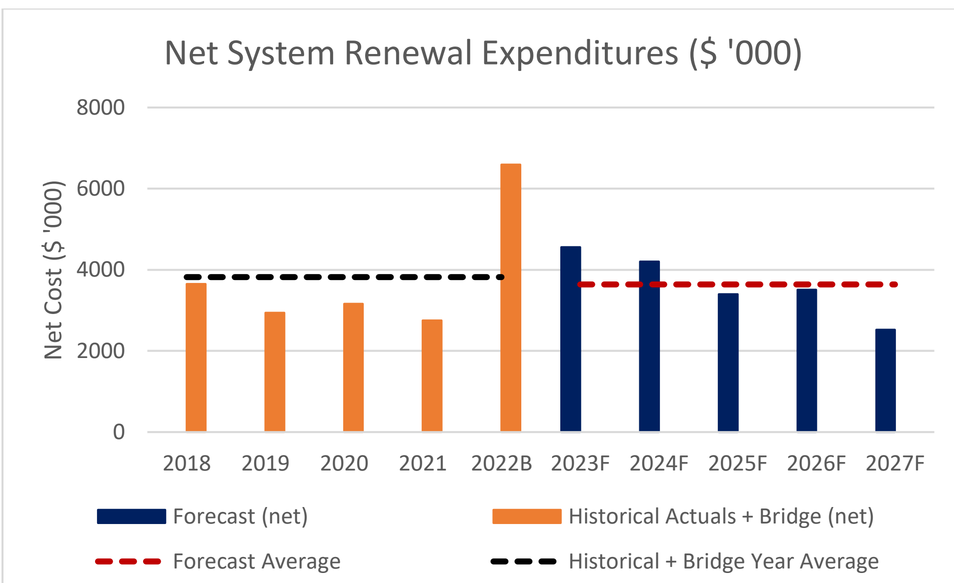


Figure 5.4-8: System Renewal Comparative Expenditures [Excl. Sub 16 ICM]

The observed decrease in forecast system renewal spending is partially driven by the need to accommodate and balance the increased level of investments required under other investment categories over the forecast period. At the same time, the level of forecast system renewal spending is reflective of the ongoing efforts needed in asset renewal to keep pace with recommendations identified in the ACA, while staying in step with customer preferences for maintaining costs, reliability, and service levels status quo.

5.4.1.3.3 System Service

As shown in Figure 5.4-9, PUC's forecast average for system service is approximately 50% lower than the historical plus bridge year average. This is primarily as a result of the significant spending associated with SSG Project, which has a net capital cost of $21.36M in 2022 and $3.19M in 2023.

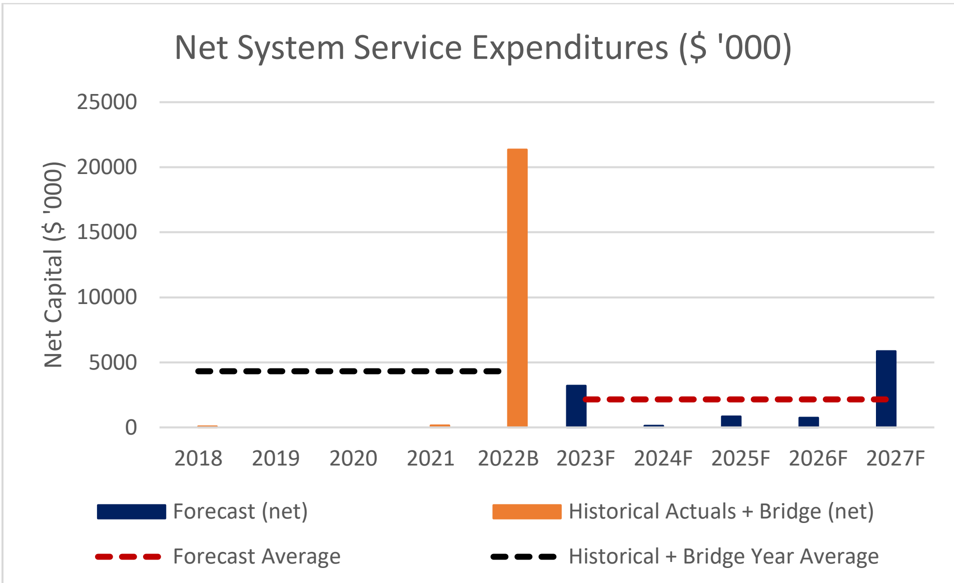


Figure 5.4-9: Net System Service Comparative Expenditures [Incl. SSG Project]

When excluding the SSG Project cost, PUC's forecast average for system service is approximately 3,238% greater than the historical plus bridge year average, as shown in Figure 5.4-10. This increase is driven by the new distribution station build in 2027 to mitigate the capacity constraints in the western part of PUC's service territory.

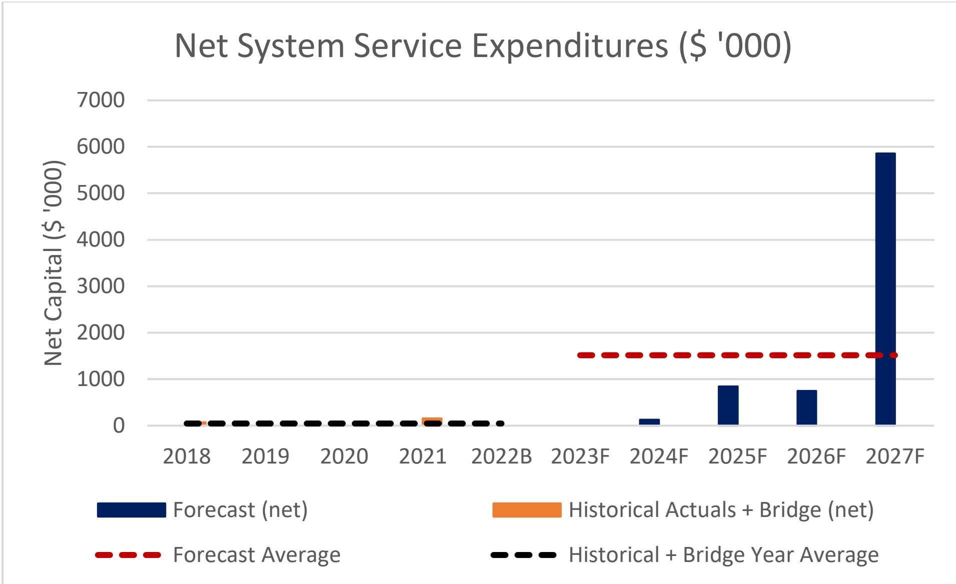


Figure 5.4-10: Net System Service Comparative Expenditures [Excl. SSG Project]

5.4.1.3.4 General Plant

As shown in Figure 5.4-11, the forecast average for general plant is approximately 280% higher than the historical plus bridge year average. This is primarily due to increased renewal investments required in buildings, tools & equipment over the forecast period, and the GIS UN Migration project planned for 2024/25.

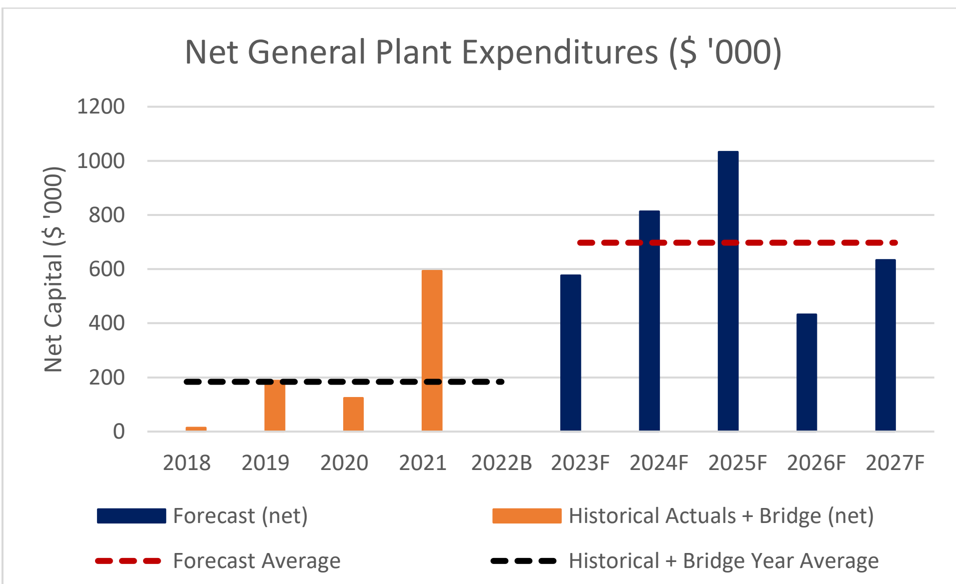


Figure 5.4-11: General Plant Comparative Expenditures

5.4.1.3.5 Overall Capital Expenditures

The overall net capital expenditure trends over the 2018 to 2027 period, including PUC's two ICM projects, are shown in Figure 5.4-12. The average overall capital expenditures forecast is approximately 24% lower than the historical plus bridge year average. This is largely as a result of the costs associated with the Substation 16 ICM and SSG Project ICM.

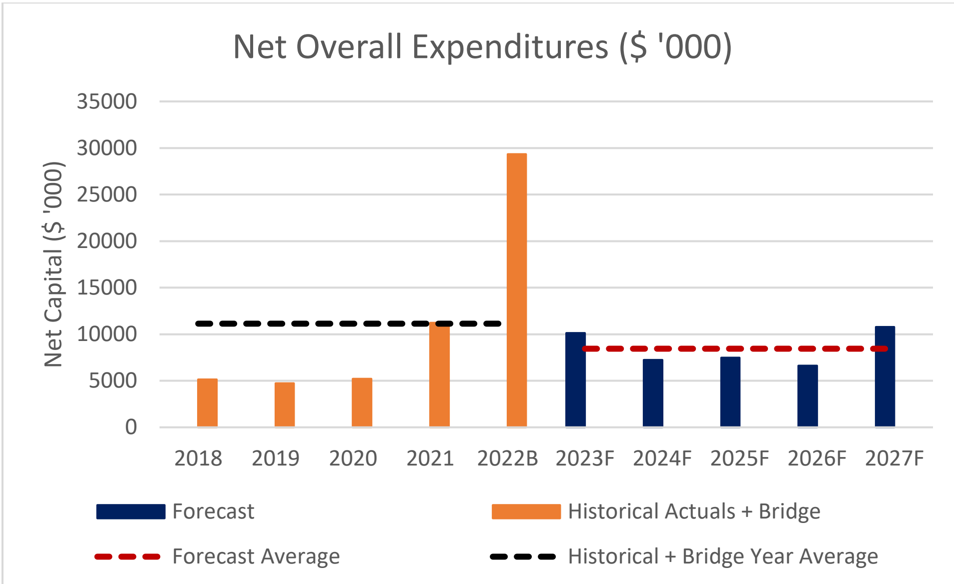


Figure 5.4-12: Overall Comparative Expenditures [Incl. Sub 16 ICM & SSG Project ICM]

When comparing overall net expenditures over the historical and forecast periods, it is important to compare expenditures on an apples-to-apples basis. Since the SSG Project is not considered to be part of PUC's normal capital expenditures, these costs should be removed to provide the OEB and interveners with a more representative comparison of the forecast expenditure compared to historical expenditures.

On the other hand, although significant substation renewal projects and new builds tend to be more costly and less frequent, they are still an expected capital expenditure for any LDC that owns, maintains and operates distribution substations. As a result, PUC's historical and forecast substation investments should both be included in the comparison of overall expenditures.

When excluding the SSG Project costs, the average overall capital expenditures forecast is approximately 14% greater than the historical plus bridge year average, corresponding to an annualized increase of 2.65%.

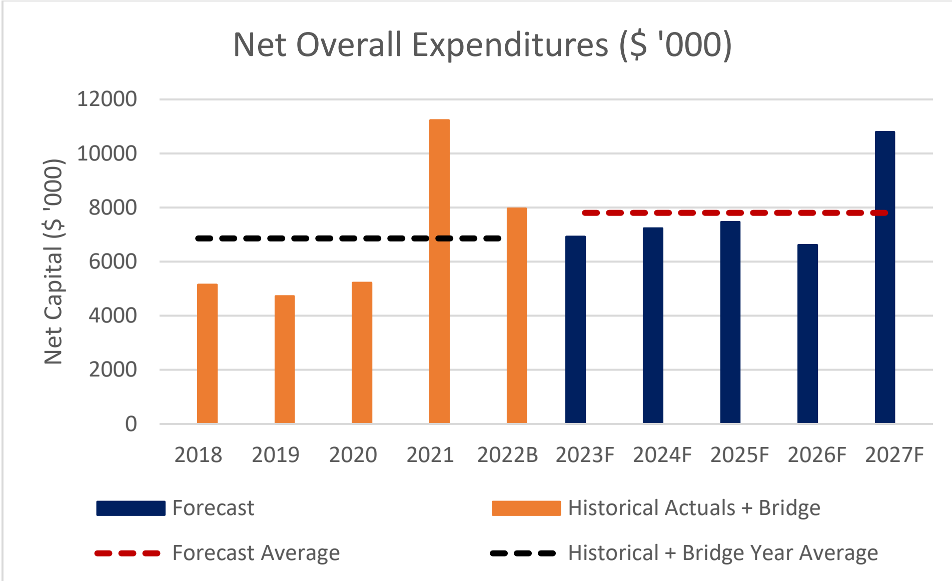


Figure 5.4-13: Overall Comparative Expenditures [Excl. SSG Project ICM only]

Given the rising cost of goods and services required to complete the forecast work, a 14% increase (or 2.65% annualized increase) over the forecast period is considered to be quite modest. This modest increase reflects the increase in system access due to anticipated development in the community, an increase in system service to mitigate the capacity constraints in the western part of PUC's service territory, and an increase in general plant required to maintain and upgrade PUC's buildings, tools & equipment and GIS system.

It should also be noted that, at the direction of the OEB, the SSG Project was accommodated through the re-prioritization of other capital expenditures. If the SSG Project did not occur, there would have been other capital expenditures in its place, so the 2022 and 2023 capital expenditure levels shown in Figure 5.4-13 may not be entirely accurate of what the 2022 and 2023 expenditures would have looked like without the SSG Project.

5.4.1.4 Forecast Impact of System Investments on System O&M Costs

System O&M costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. A distributor is expected to consider the reduction in O&M costs when planning capital investments. A description of the impacts of capital expenditures on O&M must be given for each year, or a statement that the capital plans did not impact O&M costs. A distributor must consider the trade-offs between capital and O&M when assessing alternative options to a capital investment.

Table 5.4-14 summarizes the forecast system O&M spending over the forecast period.

Table 5.4-14: Forecast System O&M Expenditures

Category	Forecast ($ '000)				
	2023	2027	2025	2026	2027
System O&M	7,280	7,644	8,026	8,428	8,849

Although PUC'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 are expected to offset growing O&M needs in other areas as assets continue to age. 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.

5.4.1.5 Non-Distribution Activities

A statement should be provided that there are no expenditures for non-distribution activities in the applicant's budget.

There are no expenditures for non-distribution activities in PUC's budget.

5.4.2 Justifying Capital Expenditures

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based.

Customer Value

Filings must enable the OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

Customers represents one of the three areas of strategic focus at the centre of PUC's five-year Strategic Plan, and meeting customers' needs and expectations is one of PUC's AM objectives. These key inputs and objectives drive PUC'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, City projects, and joint use projects, as mandatory, PUC 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 keeping power supply reliability from deteriorating below an acceptable level while also keeping the overall investment envelope for this DSP within a range which would not result in retail rates escalations beyond the affordability of PUC's customer base. This is in alignment with the top two customer priorities identified in a recent survey, which corresponds to the delivery of reasonably priced electricity services and ensuring safe and reliable electricity services.

The proposed system service investments deliver value to customers by mitigating capacity constraints in the western part of PUC's service territory, thereby allowing the connection of several large and medium sized commercial customers, which in turn will help drive economic growth within the region. PUC's general plant investments are also selected and prioritized such that PUC can continue to operate safely, efficiently and support other work.

Customer value per dollar spent is also one of the refinement criteria considered as part of PUC's prioritization process, which is detailed further in Section 5.3.1.3.

The SSG Project will also deliver direct benefits to customers through reduction in energy consumption and monthly bills, reliability improvements, and improved planning and data reporting systems, and will also deliver significant, direct GHG emissions reductions.

Technological Changes and Innovation

A distributor should also keep pace with technological changes.

There are several ongoing and proposed innovative projects that PUC is undertaking to address current issues including grid modernization, distributed energy resources (DERs) integration and climate change adaptation. The following activities are being undertaken at PUC:

- **SSG Project** – The SSG project is a community wide smart grid which will cover PUC's entire service territory. The SSG project is expected to transform PUC's entire distribution system through an integrated project implementing the following technologies:
    - Voltage/VAR Optimization: allows a utility to operate its distribution system at the lower end of the acceptable voltage ranges and reduces reactive power in the distribution system resulting in lower system losses, lower energy consumption, and an overall system energy and demand reduction.
    - Distribution Automation: provides better monitoring and control of the distribution system by providing real time data as well as the capabilities to remotely locate faults and remotely operate equipment to restore service in the event of fault or loss of upstream power
    - Advanced Metering Infrastructure: allows a utility to leverage its AMI data for better data analytics and reporting.

- **Voltage Conversion** – Completion of PUC's long standing voltage conversion project during this filling period is expected to bring benefits in a number of ways. Firstly, these remaining circuits once transferred over from 4kV to 12kV, will allow for the connection of DER as the newer 12kV feeders include the necessary protection systems to support their connection. Secondly, the elimination of multi-circuit lines along many streets should lead to a less complex and better hardened system better able to withstand more severe wind and ice loading weather conditions expected with climate change. Furthermore, the reduction in electrical losses retiring two 4kV stations and with the move to higher voltage are expected to bring advantages from an environmental perspective.

- **GIS Utility Network (UN) Migration** – PUC's existing GIS is based on Geometric Network technology, which is approximately twenty-five years old, approaching end of useful life, and will no longer be supported by the vendor in the next three years as they move exclusively to a UN platform, which is industry typical practice platform. As a result, PUC is planning to undertake a GIS UN Migration project in 2024/25, wherein all of PUC's existing asset information and custom developed applications will be migrated to the new platform.

In addition, advanced technology will be considered and incorporated in system design selectively over the forecast period. Where benefits outweigh the costs, advanced technologies may be incorporated during implementation of asset renewal projects, to meet the current and future needs of the customers, to improve operating efficiency and to support the integration of renewables and smart grid technologies.

Consideration of Traditional Planning Needs

A distributor should also integrate traditional planning needs such as load growth, asset condition and reliability.

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 PUC's AM processes.

Load growth is a direct input into PUC's planning for system access and system service type projects. At a macro-level, there are currently no overall system level capacity constraints in the supply system that would prevent connection of anticipated overall load or generation customers during the next five years. However, an analysis of loading data archived in PUC SCADA historian has revealed that a localized shift in demand is occurring in a westerly portion of the service territory and investments in additional infrastructure in that area is proposed to mitigate the capacity constraints previously discussed in Section 5.3.2.2.1.

Asset condition and reliability data are key inputs considered by PUC when identifying, selecting and prioritizing system renewal expenditures. A significantly large portion of the existing infrastructure employed on PUC's supply network has, or soon will reach a service age beyond its typical useful life. Through a recently completed ACA exercise, a significantly large fraction of critical power supply infrastructure components employed at distribution stations, overhead lines and underground distribution system have been determined to be in “fair”, “poor” or “very poor” operating condition. In the absence of investments into asset renewal, the existing infrastructure presents high risk of failure in service, affecting supply system reliability and public safety. However, renewal and replacement of all infrastructure components determined to be in “poor” or “very poor” condition during the next five years, would be difficult to manage through PUC's resources and it would lead to unaffordable increase in retail rates. Given that the highest priority concern from almost all customer engagement activities is the high cost of electricity bills and an increasing worry over affordability followed by the importance placed on reliability and customer communications, PUC's challenge is to seek an optimized balance of these generally opposing factors. Therefore, in preparing this DSP, PUC 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.

<u>Overall Capital Expenditures</u>

A distributor must not only provide information to justify each individual investment, but also the total amount of its proposed capital expenditures. A distributor should provide context on how its overall capital expenditures over the next five-years, as a whole, will achieve the distributor's objectives. Particularly, a distributor should comment on lumpy investment years and rate impacts of capital investments in the long-term.

Capital expenditure trends over the 2018 to 2027 period, for net capital expenditures and the underlying investment categories, are shown in Figure 5.4-14.

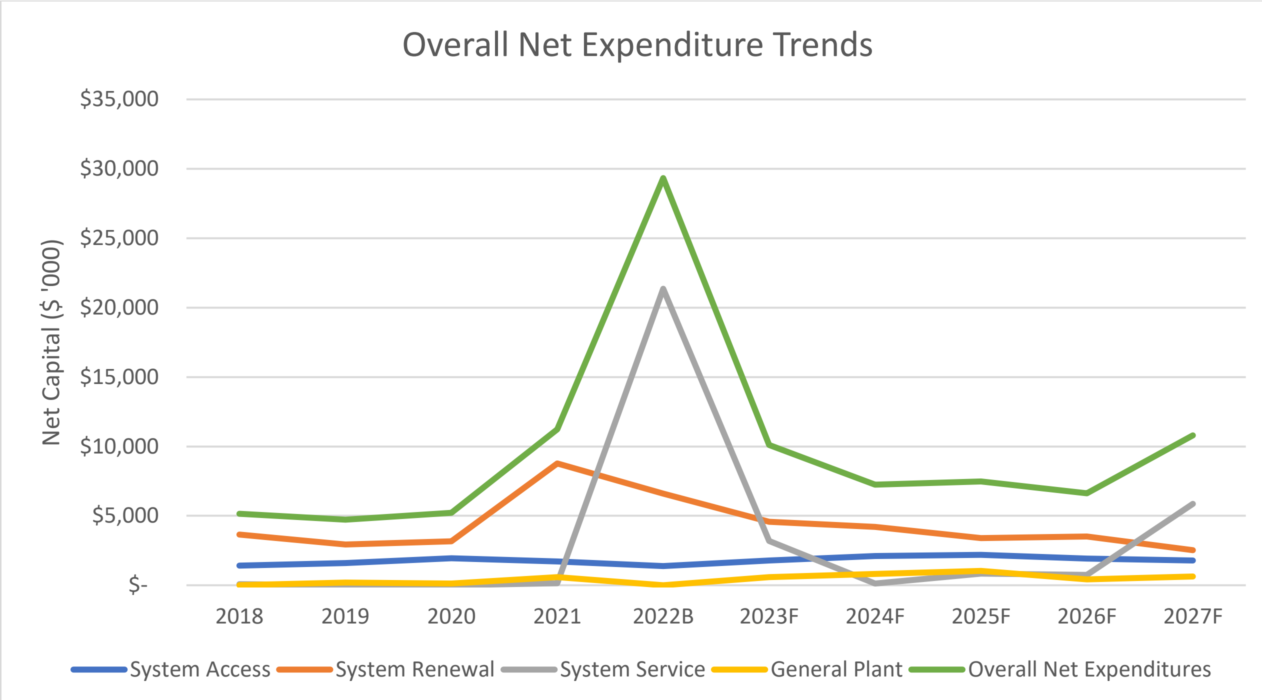


Figure 5.4-14: Overall Net Capital Expenditure Trends

Over the forecast period PUC's capital expenditures are designed to continue to meet PUC's corporate goals including safe, reliable, and affordable power. The proposed level of spending is also aimed at improving asset related performance in order to achieve the four performance outcomes established by the OEB, while also adhering to PUC's established AM Objectives set out in Section 5.3.1.1.

Over the historical period, a relatively stable trend is observed from 2018 to 2020, which is followed by a jump in costs in 2021 and 2022. As previously explained, the observed increases in 2021 and 2022 are driven by the Substation 16 ICM costs, the SSG Project ICM costs, and the additional renewal costs implemented to support the SSG Project.

Costs are reduced significantly in 2023 relative to 2022 but are still higher than other forecast years as a result of the reallocation of a portion of the SSG Project costs from 2022 to 2023 for testing and optimization purposes. Following the completion of the SSG Project, a reduced and relatively stable trend in overall net capital expenditures is observed from 2024 to 2026. This is followed by a significant increase in 2027 which is driven by PUC's proposed new station build in the west end of its service territory. This new station is required to accommodate the localized demand in this area which is being driven by requests for connection of several large and medium sized commercial customers. Additional information on this investment can be found in Section 5.2.1.4. To accommodate the increased level of investment associated with this new station build, PUC has decreased the level of investment elsewhere in its budget (i.e., system renewal) to help balance the overall budget and limit the overall impact on rates.

As previously noted in Section 5.4.1.3.5, when excluding the SSG Project costs, the average overall capital expenditures forecast is approximately 14% greater than the historical plus bridge year average, corresponding to an annualized increase of 2.65%. Given the current rate of inflation[7] , investments over the next five years will allow PUC to continue to meet customer and system needs while also keeping the rate impact to customers at or below future inflation.

5.4.2.1 Material Investments

The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g., unique characteristics; marked divergence from previous trend) are supported by evidence that enables the OEB's assessment according to the evaluation criteria set out below. The level of detail filed by a distributor to support a given investment project/program should be proportional to the materiality of the investment.

For this Application, the materiality threshold is $135,000. All capital projects, proposed to be implemented during the Test Year, with investments level exceeding the materiality threshold, are listed in Table 5.4-15. The project prioritization criteria along with scoring to determine project priority rankings are shown in Table 5.4-16.

The first five projects in the table fall in the system access category for which meeting the regulatory obligations is the primary driver. Of the next 13 projects in the table, one corresponds to the SSG Project, ten belong to the system renewal category, for which supply system reliability and public safety are the primary drivers, and the final two projects belong in the general plant category, for which business operations efficiency and non-system physical plant are the primary drivers. Detailed scope of each project along with its key driver and justification are described in detail in Appendix A and briefly summarized below.

In addition to these material Test Year projects, PUC is also proposing to undertake a GIS upgrade/ UN migration project in 2024/25. A formal business case is not yet available for this project as it is not being undertaken in the Test Year, however additional project information is included in Section 5.4.2.1.1 below.

[7] Consumer Price Index by product group, monthly, percentage change, not seasonally adjusted, Canada, provinces, Whitehorse, Yellowknife and Iqaluit. Reference Period: May 2022. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000413&pickMembers%5B0%5D=1.2&cubeTimeFrame.startMonth=05&cubeTimeFrame.startYear=2022&referencePeriods=20220501%2C20220501

Table 5.4-15: Proposed Capital Investments during Test Year - Projects over Materiality

Category	Project Code	Project Description	Priority Rank	2023 Planned Expenditure ($ '000)
System Access	1C100-1	Customer Demand - Services	1	924
System Access	1C100-2	Customer Demand - New Subdivisions	1	301
System Access	1C100-3	Customer Demand - Joint Use	1	171
System Access	1C100-4	Customer Demand - City Projects	1	201
System Access	1C100-7	Revenue Meters	1	187
System Renewal	1C200-1-1	Unplanned OH Renewal (forced)	1	276
System Renewal	1C200-1-2	Unplanned UG Renewal (forced)	1	376
System Renewal	1C300-1-5	OH Renewal - Transformers (PCBs)	1	711
System Service	1C400-1-1	System Wide - Sault Smart Grid (SSG) Project	2	3,190
System Renewal	1C300-1-3	OH Renewal - Voltage Conversion	3	864
System Renewal	1C300-1-4	OH Renewal - Restricted Conductor	4	362
System Renewal	1C300-1-2	OH Renewal - Poles	5	602
System Renewal	1C3033-3-3	Stations Renewal - Switchgear, Protection & Control Renewals	6	176
System Renewal	1C300-2-8	UG Renewal - Vaults	7	401
System Renewal	1C300-3-1	Stations Renewal - Building & Fence Repairs	8	144
General Plant	1C500-2-1	Buildings	9	238
General Plant	1C500-2-1	Tools & Equipment	10	295
System Renewal	1C300-1-1	OH Renewal - General Asset	11	172
Total Net Expenditure on Material Projects During Test Year				**9,591**
Total Net Expenditure on Capital During Test Year (All Investment Categories)				**10,113**

Table 5.4-16: Prioritizing Matrix for Test Year Projects over the Materiality Threshold

Rank	Area	Project / Program	Public Safety Impact				Outage Customer Impact				Customer Value for $				System Service Improvements				Project Interdependence				Score (%)
			Weight: 40%				Weight: 10%				Weight: 15%				Weight: 10%				Weight: 25%				
			R	C	PSI	PSI (n)	QTY	HRS	COI	COI (n)	$k	C	CV	CV (n)	QTY	SIV	SSI	SSI (n)	SQI	FI	PI	PI (n)	
1	System Access	Services, New Subdivision, Joint Use, City Projects, Revenue Meters	Ranked as first priority as these are non-discretionary (Customer/External Driven)																				n/a
1	System Renewal	Unplanned OH & UG Renewal																					n/a
1	System Renewal	OH Renewal - Transformers (PCBs)	Ranked as first priority as these are non-discretionary (Regulatory Compliance)																				n/a
2	System Service	System Wide – Sault Smart Grid (SSG) Project	0	0	0	0.0%	33000	1.81	59747	7.7%	24548	33000	1.3	0.3%	33000	5	165000	8.7%	2.5	2.5	6.3	1.1%	17.8
3	System Renewal	OH Renewal - Voltage Conversion	1	1	1	0.3%	82	1.5	123	0.0%	864	82	0.1	0.0%	82	1	82	0.0%	10	10	100.0	17.4%	17.7
4	System Renewal	OH Renewal - Restricted Conductor	7.5	5	38	9.5%	111	3	333	0.0%	362	111	0.3	0.1%	111	1	111	0.0%	5	5	25.0	4.4%	14.0
5	System Renewal	OH Renewal - Poles	5	10	50	12.7%	480	1.5	720	0.1%	602	480	0.8	0.2%	480	1	480	0.0%	1	5	5.0	0.9%	13.9
6	System Renewal	Stations Renewal - Switchgear, Protection & Control Renewals	2.5	10	25	6.4%	2357	2.5	5893	0.8%	176	2357	13.4	3.2%	2357	5	11786	0.6%	0	0	0.0	0.0%	11.0
7	System Renewal	UG Renewal - Vaults	5	5	25	6.4%	1000	4	4000	0.5%	401	1000	2.5	0.6%	1000	5	5000	0.3%	2.5	2.5	6.3	1.1%	8.8
8	System Renewal	Stations Renewal - Building & Fence Repairs	2.5	5	13	3.2%	2357	1.5	3536	0.5%	144	2357	16.3	3.9%	2357	0	0	0.0%	0	0	0.0	0.0%	7.5
9	General Plant	Buildings	0	0	0	0.0%	0	0	0	0.0%	1750	33000	18.9	4.5%	33000	0	0	0.0%	0	0	0.0	0.0%	4.5
10	General Plant	Tools & Equipment	0	0	0	0.0%	2357	1	2357	0.3%	295	2357	8.0	1.9%	2357	2.5	5893	0.3%	0	0	0.0	0.0%	2.5
11	System Renewal	OH Renewal - General Asset	2.5	2.5	6	1.6%	100	4	400	0.1%	172	100	0.6	0.1%	100	1	100	0.0%	1	1	1.0	0.2%	2.0

Notes Regarding Ranking Methodology:

1) Public Safety Impact (PSI) due to failure = Risk (R) x Consequence (C) where (R = (1 = low, 10 = high), C = (1 = low, 10 = high)
2) Customer Outage Impact (COI) = (Qty Customers Affected (QTY) x anticipated outage hours/year (HRS))
3) Customer Value (CV) = Customers Served (C) / $100,000 ($K)
4) System Service Improvements (SSI) = Quantity of Customers Affected (QTY) x Service Improvement/Enhancement Value (SIV) factor, (1 = low, 5 medium, 10 = high)
5) Project Interdependence (PI) = Impact of a project not proceeding negatively impacting the ability to complete other future planned work = (SQI = service quality impact x FI = financial impact), values (1 = low, 10 = high)
6) Score = Sum of five factors above (Public Safety, Outage Customer Impact, Customer Value, System Service Improvements and Project Interdependence after weighting each according to weighting shown in the spreadsheet above allowing for a maximum attainable score
7) (n) represents a normalized score where for the ranked projects, each is normalized to a scale of 0%-20%
8) Rank is determined by placing Scores for all planned capital projects in a rank ordered list. A rank of 1 represents the highest priority. Non-discretionary customer demand work and capital work driven by unplanned repairs and regulatory compliance have all been weighted equally and assigned a Rank of 1
9) It is noted that the projects within this matrix are those previously screened through the Asset Management Plan process, and they therefore represent only the most critical projects identified and prioritized through that process.

System Access: Services, New Subdivision, Joint Use, City Projects, Revenue Meters (Ranked #1)

These projects are required to fulfil PUC's regulatory obligations under its Condition of License and Conditions of Service, and are primarily driven by customer demand. The first project involves fulfilling customer requests for new services or upgrade of existing services. The second project covers requests from land developers involving servicing of multiple lots within subdivisions. The third project covers requests from telecommunication companies in the City for make ready work to facilitate joint use of distribution infrastructure by third parties. The fourth project involves meeting requests from the municipality to relocate overhead or underground lines installed in the public right-of-way to coordinate with road widening projects. The fifth project is related to the supply, installation and maintenance of revenue meters installed at each customer service point for retail settlement and billing purposes for all customers connected to PUC's distribution system.

Forced System Renewal: Unplanned OH & UG Renewal (Ranked #1)

These two projects involve reactive expenditure to restore power following a power interruption caused by equipment failures by replacing the failed and unsafe distribution system assets with new equipment. These expenditures are required in accordance with PUC's Condition of License and the DSC. The key drivers for these projects are supply system reliability and public safety, because when equipment has failed in service, the proposed expenditure becomes necessary to restore power and remove the unsafe equipment from service. Unplanned OH renewal is intended to cover expenditure for renewal of failed assets on overhead lines and Unplanned UG Renewal is intended to cover expenditure for renewal of assets on underground distribution system.

System Renewal: OH Renewal - Transformers (PCBs) (Ranked #1)

This project involves the replacement of PUC's remaining PCB-contaminated pole mounted transformers in accordance with PCB regulations, which set a deadline of December 31, 2025 to eliminate electrical transformers with concentrations of PCB's greater than 50 ppm. This is a high priority investment in accordance with the Federal PCB regulations.

System Service: System Wide – Sault Smart Grid Project (SSG) (Ranked #2)

As previously noted, the SSG Project will transform PUC's distribution system by integrating technologies that allows for voltage optimization, monitoring of the distribution system, and leveraging real time data. This will improve PUC's system reliability and operational effectiveness, while positioning PUC for future growth and grid modernization.

Since $3.19M of the SSG Project net spend has been reallocated to the 2023 Test Year, PUC has included the SSG Project in its prioritization process to demonstrate the priority of the project relative to other material investments proposed in the Test Year. The SSG Project is ranked #2 out of 11, following the non-discretionary projects detailed above. Further justification for the prioritization of the SSG Project is included in Section 5.3.6.2.1.

Since the SSG Project has been pre-approved as part of the EB-2020-0249/EB-2018-0219 ICM application, PUC has not prepared a material investment narrative for this project.

System Renewal: OH Renewal - Voltage Conversion (Ranked #3)

This program involves renewal of overhead distribution system assets by rebuilding of the existing overhead distribution system currently operating at 4.16 kV. The overhead lines will be rebuilt to operate at 12.47 kV upon completion of the projects. As detailed in PUC's asset condition assessment report, PUC has approximately 22 km of 4.16 kV line and two 4.16 kV distribution stations in service (Substations 4 and 5), most of which is in poor condition and at the end of their service life.

Project interdependence is the primary criterion that impacted the scoring of this project, as the work proposed will bring an end to PUC's voltage conversion program which is essential to allowing the retirement of the final two remaining end of life 4.16 kV stations (i.e., Substation 4 and 5) and retirement of all remaining 4.16 kV stock from storage, tools and training. Completion of the long-standing voltage conversion program will simplify, standardize and improve the overall performance and efficiency of the distribution system. There are 82 customers immediately impacted by the remaining works under this program.

<u>System Renewal: OH Renewal - Restricted Conductor (Ranked #4)</u>

PUC has identified #6 copper overhead primary conductor as a safety hazard. It is classified by PUC as "restricted wire". Due to the nature of the conductor, it being small and constructed of copper, its tensile strength is known to degrade over years of use. Due to this, the conductor is prone to failure. Additionally, when the conductor fails, due to its nature, the fault current dissipates quickly and therefore may not trigger the nearest protective equipment. This may cause the conductor to remain energized in an area where staff or the public may come into contact. The conductor is replaced with #2ACSR, along with related insulation and aged and poor condition infrastructure. The specific project areas covered by this project are identified in the supporting material narrative.

Public safety impact is the predominant criterion that impacted the scoring of this project since the risk of failure is relatively high. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service but working around restricted conductor can be handled through work procedures until all restricted conductors can be removed. PUC has already eliminated the risk from high public traffic areas, parks, and schools to limit the consequence of a failure, but the work proposed over the DSP period is required to continue eliminating the risks associated with the #6 conductor. There are 111 customers immediately impacted by the projects planned for the 2023 Test Year.

<u>System Renewal: OH Renewal – Poles (Ranked #5)</u>

This project involves replacement of poles determined to be "unsafe" due to degradation of their structural strength, based on in-situ testing of the poles. For the forecast period, PUC plans to replace approximately 60 wood poles per year.

Public safety impact is the predominant criterion that impacted the scoring of this project due to the potential failure mode of this asset class, with an assumed average impact of eight customers per pole (or 480 customers impacted annually). Deferring or reducing the quantities of poles proposed for replacement will result in an increased safety and reliability risk.

<u>System Renewal: Stations Renewal - Switchgear, Protection & Control Renewals (Ranked #6)</u>

This project involves the renewal of stations assets. As identified through the ACA, a number of breakers associated with the switchgear have reached end of life and are at greater risk of failure.

Public safety impact is the primary criterion that impacted the scoring of this project, followed by customer value for dollars spent. In case of an outage or loss of a main breaker at one of PUC's 14 distribution stations, over 2,350 customers would be affected on average. In terns of non-operational breakers, a fault could lead to high liability consequences such as shock, burn, or fire. PUC is proposing to replace two station breakers per year over the forecast period. Deferring or reducing these planned renewals will result in an increased safety and failure risk.

<u>System Renewal: UG Renewal – Vaults (Ranked #7)</u>

This project involves the rejuvenation of underground vaults and manholes that have been identified as deficient and are therefore more prone to failure. PUC is proposing to proactively rejuvenate one major vault and two minor vaults per year over the forecast period, as well as a manhole rejuvenation in the test year.

Public safety impact is the primary criterion that impacted the scoring of this project. A failure of a vault or manhole could pose significant safety hazards to workers and the public, while also impacting the reliability and effective operation of the system. A single failure could impact 250 customers.

System Renewal: Stations Renewal - Building & Fence Repairs (Ranked #8)

PUC has identified the need for a station building and fences repair program to ensure the upkeep of the buildings and fences that are required for the safe and efficient operation of stations in the system. Failure risk and safety are primary drivers for this project.

Customer value for dollars spent and public safety impact are the primary criteria impacting the scoring of this program. Since PUC has 14 stations, it is assumed that over 2,350 customers would be impacted on average per station. Other than the handful of grounding repairs and breached station fence repairs anticipated, the balance of other repairs does not constitute an immediate material safety risk. However, if left unaddressed for too long, they are expected to lead to a decrease in service levels through reliability reductions and lead to the need for much more costly remedial solutions in the long term. (e.g., the need to replace an entire switchgear cubicle or overhead structure due to advanced rust rather than sanding and painting minor rusting areas proactively).

General Plant: Buildings (Ranked #9)

This project involves the renewal of buildings. PUC is planning to invest in the upkeep of PUC's main facility, which represents the critical backbone of PUC's 24/7 operations. Ongoing investments in this facility are required to ensure safe and reliable continuation of PUC's operations.

The proposed building investments have been ranked as 9th out of the 11 initiatives for the Test Year. Impacts in the area of safety, customer outages, system service and project interdependence are minimal relative to other projects. As a result, the benefits to be derived from this project are primarily in the area of customer value for dollars spent, where customer dollars are focussed on eliminating inefficiencies that over time would lead to burdensome O&M expenses or costly unplanned capital expenditures to address if deferred for too long. All PUC customers will derive value from this project.

General Plant: Tools & Equipment (Ranked #10)

This project involves the renewal of tools/equipment. The planned investments in tools/equipment will help improve PUC's testing and inspection regimes which in turn will enable PUC to make better informed asset investment decisions in order to continue providing safe, reliable and effective services to customers.

Customer value for dollars spent is the primary criterion that impacted the scoring of this project. The equipment proposed to be purchased is critical in PUC being able to carry out their testing programs and gather further data to enable PUC to continue to determine the condition of assets and develop an informed ACA process. This data is then used as an input to help inform the investment plan.

System Renewal: OH Renewal - General Asset (Ranked #11)

This project involves small unplanned projects over the forecast period that are not considered emergency repairs. This includes the removal, cleanup and disposal of pole butts and the replacement of minor assets in poor condition which are identified through maintenance programs, field inspections and/or information provided from third parties.

Public safety impact is the primary criterion that impacted the scoring of this project, however this is a lower priority investment relative to other material projects detailed above. Although the safety risks of the pole after the wires and related infrastructure have been minimized, completion of the project immediately impacts PUC's image in the community, and it is important to complete the projects and restore the network to pre-existing conditions. Given that this investment involves a variety of projects, PUC has assumed that approximately 100 customers would be impacted annually if this work was to be deferred.

5.4.2.1.1 GIS UN Migration Project

The GIS system is used as PUC's primary asset registry, keeping track of the location and important attributes for all assets in the field. The data stored in the GIS is utilised by all aspects of the company and is a critical part of the operational infrastructure. Importantly, the data stored in the GIS is used by the operations group to perform activities ranging from responding to outages to field maintenance. This can include switching and load transfers during outages. It is imperative that the data is 100% accurate to ensure field staff are directed to the correct equipment when undertaking these activities. The GIS is used on a daily basis.

An assessment took place in 2020 regarding the current use of PUC's GIS. It was determined that using the "current" approach left PUC behind in today's evolving GIS technology and behind what is considered industry typical practice. Many LDCs are already utilizing tablets and smart phones in the field to view and update information. In January 2021, ESRI Canada was consulted to provide a gap analysis and assist in developing a technology roadmap for the migration to the Utility Network (UN). The output of the services engagement provided a current state assessment, future state and implementation roadmap that will identify and address high-priority operational and technical governance-related requirements.

PUC's existing GIS is based on Geometric Network technology, which is approximately twenty-five years old, approaching end of useful life, and will no longer be supported by the vendor in the next three years as they move exclusively to a UN platform. The UN technology is replacing the geometric network which has a more open web-based architecture. It is the latest model, that is becoming typical industry practice, and allows for enhanced performance with applications such as ArcGIS Portal and ArcGIS Online, enhanced field mobility and direct editing. ArcGIS Desktop is the application that will be replaced with ArcGIS Pro which is already in production.

As a result, PUC is planning to undertake a GIS UN Migration project in 2024/25, wherein all of PUC's existing asset information and custom developed applications will be migrated to the new platform. Migration to the new platform, including all of PUC's existing asset information and custom developed applications is expected to take two years. The current cost estimate for the project is between $900,000 - $1,200,000. The diagram below shows the current propose phases (one to three) defined as Design, Execution and Transition.

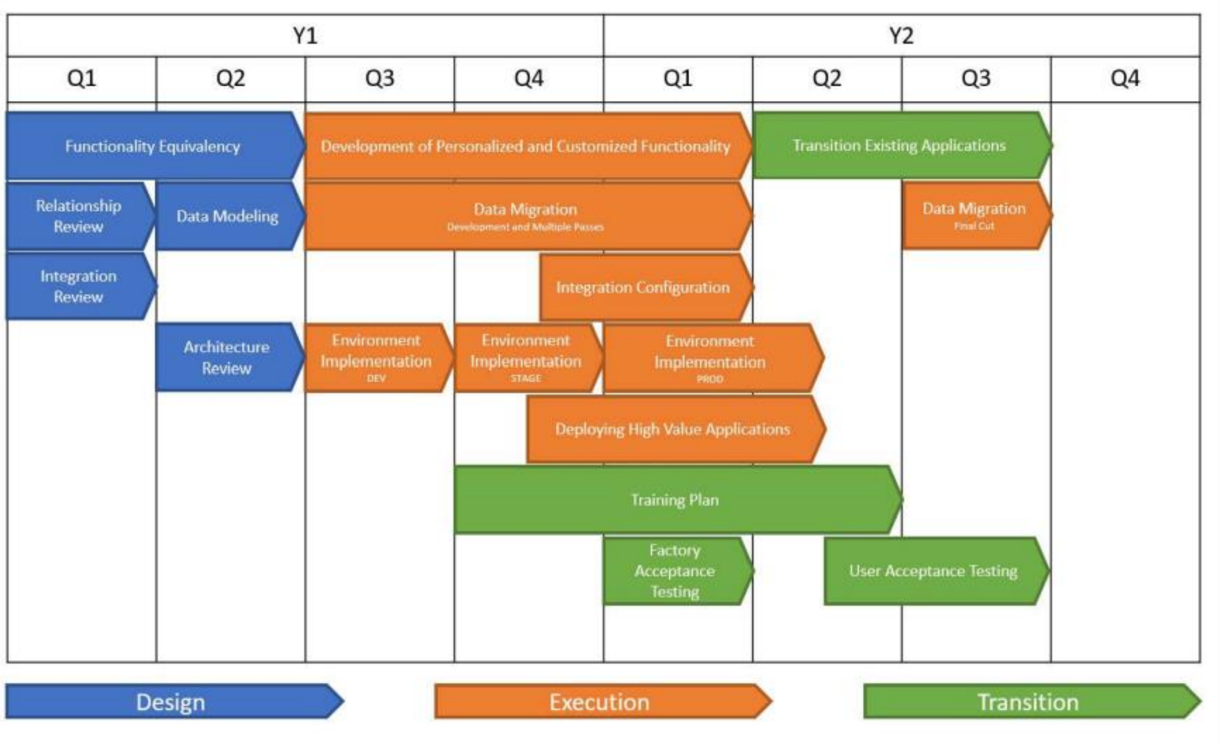


Figure 5.4-15: GIS UN Migration Project Phases

The primary driver for this project is technology obsolescence, with it becoming unsupported by the vendor in the next three years. If PUC does not upgrade the GIS, a vital backbone to PUC's operations, such that it is supported, it could significantly impact PUC's ability to manage the grid safely, effectively and efficiently.

In addition, by moving to the UN platform this will allow PUC to modernize and implement industry best practices such as field staff being able to access GIS on their tablets and phones to access the latest information as well as update it straight away. This not only ensure field staff have the most up to date information to respond and perform their tasks, but it also enables efficiency in the inputting of data from the field, responding to work request and outages. Rather than documenting this information on paper and then inputting this back at the office, this only needs to be recorded once and straight onto the live system.

PUC is currently reviewing and working with the vendors to put a detailed plan together to deliver this project in 2024 and 2025. This will include a more detailed scope and updated costs.

Appendix A

Material Investment Narratives

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

CUSTOMER DEMAND – SERVICES

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

In an effort to comply with the Distribution System Code (DSC) requirements and to support ongoing customer demand and customer-initiated requests, service projects have been budgeted based on historical expenditure trends and predictions from the City of Sault Ste. Marie regarding project developments. Service projects vary from year to year and may include installations of new/upgraded residential services, commercial services, new transformers to support services, replacement/relocation of infrastructure due to customer requests, and other miscellaneous requests from customers. New connections and service upgrades are planned using standardized designs that meet the requirements of O. Reg. 22/04, made under the Electricity Act, 1998. All requests are also reviewed against the DSC requirements and reasonableness to determine PUC's contribution level.

As part of this program, PUC typically installs between 50 and 100 new residential services annually contingent upon the local economy. Many of the new services installed are located in residential subdivision areas, requiring minimal distribution system upgrades. Some new/upgraded services in existing areas require distribution system upgrades to service the customer. These upgrades include, but are not limited to pole replacements, transformer installations/replacements and system expansions.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Year-over-year fluctuations in the volume of work performed under this program vary based on the number of customer requests received each year. The timing of work depends on when the customer request is made.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)				Forecast Costs ($ '000)					
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	628	1,191	1,080	1,331	1,164	1,254	1,273	1,294	1,364	1,274
Contributions	(89)	(163)	(169)	(238)	(322)	(330)	(343)	(350)	(357)	(364)
Capital (Net)	539	1,028	911	1,093	842	924	929	944	1,007	910

4. Economic Evaluation (Expansion Projects)

This is generally not applicable. From time to time a new residential service will require an extension of our electrical distribution system. In such scenarios, PUC follows the regulated process within the DSC to fairly expand the electrical distribution system.

5. Comparative Historical Expenditure

The historical costs for services are identified in Section 3 of this document. Typically, the number and scope of services will fluctuate each year depending on the requests made by customers. Expenditures under this program are forecast based on historical trends and considerations of forecast growth and development.

6. Investment Priority

This investment program is classed as a high priority since it is a non-discretionary program driven by customer service requests and regulatory compliance. When customer connection and service upgrade requests are initiated, they will take priority over other system undertakings and plans.

7. Alternatives Analysis

Since this is a non-discretionary program, doing nothing is not a viable option. Alternatives are considered on a case-by-case basis, and the most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	PUC considers options when services are installed/revised on a case by case basis to provide the most cost-effective solution for all parties. Where appropriate, PUC might also revise timing of planned projects within similar areas to gain overall economic efficiencies.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	The main benefit to customers is timely connection to the electrical system and having access to safe and reliable electricity. By assuring sustainable, reliable, cost-effective electrical services to customers in PUC's service territory, this program contributes towards economic development in the region as well.
Reliability	There will be negligible impact to reliability performance resulting from this project. Very minor upgrades to individual services should result in less long-term outages for the individual customer.
Safety	All new/upgraded services are installed to the most current safety standards available ensuring safety for all.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Mandated Service Obligations* - This program is driven by customer requests and regulatory compliance. It is essential for PUC to maintain customer satisfaction and compliance with the DSC by providing all customers with access to safe and reliable electricity.

ii. Secondary Drivers: *New Customers, Increased Revenue & Customer Relations* - This investment will increase the quantity of customers supplied by PUC and revise service sizes affecting revenue stream. Replacing/relocating assets to accommodate customers provides PUC with an opportunity to improve customer relations and replace assets at a reduced cost through customer contributions.

iii. Information Used to Justify the Investment: The new connections and service projects are based on customer requests and vary year to year based on need. The number of customer connections and service upgrades are forecast based on historical trends and projections from the City of Sault Ste. Marie regarding project developments and population growth. At a minimum, PUC meets with the City annually to coordinate and to review anticipated development and associated growth. Additional information on PUC's engagement efforts are included in Section 5.2.2 of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives *considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).*

i. *Demonstrating Accepted Utility Practice*: PUC informs customers that it is their responsibility to coordinate third party services to be installed. PUC provides contractor information to customer for the customer to obtain benefits of installing multiple utilities in the same excavation. PUC designs and installs services as per USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access. All new/upgraded services are installed to the most current safety standards.

ii. *Cost-Benefit Analysis*: PUC considers options when services are installed/revised on a case by case basis to provide the most practical and cost-effective solution for all parties. PUC also considers other projects when installing new services. If the service is within the area of an upcoming project, PUC might revise timing of projects to gain overall economic efficiencies.

iii. *Historical Investments & Outcomes Observed*: PUC routinely provides new connections and service upgrades to its customers. These investments have enabled unrestricted access to the distribution system which in turn has allowed continued growth and development within SSM. They also allowed PUC to ensure dependable and reliable service for its customers.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

CDM is not applicable for new customer connections and service upgrades.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this investment.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

CUSTOMER DEMAND – NEW SUBDIVISIONS

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

To comply with Distribution System Code (DSC) requirements and support ongoing customer demand, subdivision projects have been budgeted for the forecast years based on historical expenditures and predictions from the City of Sault Ste. Marie on development. The projects include installations of new subdivisions inclusive of the expansion of PUC's distribution system and transformation up to property lines for projected residential customers. To service many of the expansions, 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 reasonableness to determine PUC's contribution level.

PUC is currently anticipating approximately five major subdivision developments in the 2023 Test Year for the connection of approximately 150 new lots throughout PUC's service territory. These subdivisions are listed below, however the subdivisions listed may or may not proceed and additional subdivisions may be presented.

- Allen's Side Road
- Eastside Subdivision
- Fox Run Subdivision
- Jack Roderick Way
- Queensgate Greens

Where possible, capital contributions towards the cost of these projects are collected by PUC in accordance with the DSC and the provisions of its COS.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Key factors that may affect timing include funding and preliminary payments from customers/developers; procurement and sourcing of materials and labour to complete installation. In addition, the schedule for these types of projects is largely dictated by third-party developers and is therefore outside of PUC's control.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018*	2019*	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	(1)	65	81	416	299	376	382	388	409	382
Contributions	0	6	(18)	(80)	(63)	(75)	(78)	(80)	(81)	(83)
Capital (Net)	(1)	70	63	336	236	301	304	308	328	299

Negative capital and positive contribution amounts are due to timing issues around receiving contributions from developers.

4. Economic Evaluation (Expansion Projects)

Subdivisions typically involve an expansion of the electrical distribution system. As outlined in the DSC, capital contributions received from subdivision developers are calculated considering the initial cost of the expansion, operation and maintenance costs and anticipated revenue to be received by PUC. An example of an economic evaluation is shown in Figure 1 below for reference.

Net Present Value Summary

	With taxes	Without Federal and Provincial taxes
1. PV of Operating Cash Flow		
a) PV of Net Operating Cash Flow	130,034	130,034
b) PV of Taxes	-34,459	0
PV of Operating Cash Flow	95,575	130,034
2. PV of Capital	-175,000	-175,000
3. PV of CCA Tax Shield	17,852	
NET PRESENT VALUE	($61,573)	($44,966)

Figure 1: NPV Summary Example

Economic evaluations for the five major subdivision developments expected in the 2023 Test Year are not available at the time of writing since the project details including scope, budget and schedule are still under development. Economic evaluations will be completed closer to project execution once the project details are finalized.

5. Comparative Historical Expenditure

Connecting new subdivisions is an ongoing annual activity for PUC. Historical costs for subdivisions are identified in Section 3 of this document. Typically, the scope of subdivision developments will fluctuate each year depending on third-party requests. PUC considered historical spend, projected growth, inflation and other supply chain and material cost factors when generating the forecast costs for this program.

6. Investment Priority

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. Alternatives Analysis

Since these are non-discretionary projects, doing nothing is not a viable option. PUC reviews options for subdivision projects on a case by case basis to ensure the solution is designed and constructed in a safe, low maintenance and economical manner for all parties. An initial design is presented to the developer with the option to discuss alternatives based on the developer needs for their subdivision projects. The final decision is made considering safety, regulatory, system reliability, economics and customer relations.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC associated with the subdivision work.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

Currently there are no Leave to Construct (LTC) approvals required as part of this program. However, if tasks arise that require LTC approval, PUC will follow the required protocol.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Although this program will typically have no impact on existing system operation efficiency, PUC strives to pursue efficiency and cost-effectiveness with regards to the execution of any subdivision developments within its service territory.
Customer Value	Customers benefit by being supplied with reliable service built to current standards. By assuring sustainable, reliable, and cost-effective electrical services to customers, this program also contributes towards economic development in the region.
Reliability	When designing new system expansions to accommodate subdivisions, PUC evaluates its whole system to identify opportunities to improve safety, reliability, and system redundancy. For example, some expansions caused by subdivision developments provide PUC with an opportunity to further loop its system to reduce outage areas more effectively as they occur. Expansions also allow PUC to review circuit and system imbalances, and further balance the electrical

Primary Criteria for Evaluating Investments	Investment Alignment
	system through connection of additional demand. Through this, customers will have more reliable access to electricity.
Safety	All new subdivision work considers safety as paramount by designing and installing to USF standards and PUC standards, in coordination with municipal road allowance standards and/or specifics approved by a Professional Engineer.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Mandated service obligations* – These projects are mandatory, and the scope and timelines are based on requirements put forth by developers and/or obligations set forth in connecting customers in the DSC. PUC considers and complies with all requirements while ensuring all installations add to a safe, efficient, and reliable system.

ii. Secondary Drivers*: New Customers, Increased Revenue & Customer Relations* – This program will increase the quantity of customers supplied by PUC affecting revenue stream. Expanding the distribution system to connect new subdivisions and in turn, individual customers, provide PUC with an opportunity to improve customer relations.

iii. Information Used to Justify the Investment*:* PUC's subdivision investments are driven by regulatory compliance and customer demand. Subdivision investments are forecast based on historical trends and projections from the City of Sault Ste. Marie regarding project developments and population growth. Additionally, PUC consults with primary subdivision developers on an ongoing basis to inquire about upcoming plans to ensure PUC is prepared.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: PUC informs developers that it is their responsibility to coordinate third party services to be installed. PUC provides contractor information to developer for the developer to obtain benefits of installing multiple utilities in the same excavation. PUC designs and installs as per the latest CSA, USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access.

ii. *Cost-Benefit Analysis:* Subdivision alternatives are considered on a case by case basis to provide the most practical and cost-effective solution for all parties.

iii. *Historical Investments & Outcomes Observed:* PUC routinely accommodates new subdivision 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 Sault Ste. Marie.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

CUSTOMER DEMAND – JOINT USE

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC is a partner with multiple third-party communication companies in Sault Ste. Marie. Third-party communication companies request to attach to PUC poles to minimize infrastructure. In doing so, PUC charges a monthly rental fee established in agreements between each company. On a regular basis, third-party companies will apply for revisions to their existing attachments or for new attachments to be added to coordinate with their business objectives and customer demand. When applications are received, it is identified whether the existing PUC infrastructure is adequate to support the new/revised infrastructure in a safe manner. If PUC's infrastructure requires revisions (make ready work), the work is performed by PUC on a time and material basis.

Currently, PUC limits the number of attachments on a PUC pole to three. Ensuring a single attachment company resides on a maximum of one attachment position allows other third-party companies the same potential benefit.

Investments within this program are geared towards “make-ready” work on PUC infrastructure which may include replacement/installation of poles, anchors and related infrastructure.to accommodate the use of this equipment by joint use partners. Joint use projects are expected to increase between 2023-2025 to accommodate the government initiatives to increase broadband coverage in rural areas but are expected to return to standard values afterwards.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Tasks under this project occur throughout the year as requested by third party companies and is therefore outside of PUC’s control. Resource constraints might also affect the timing of the work. New regulations further accelerating response requirements may further impact resource concerns as well.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ ‘000)					Forecast Costs ($ ‘000)				
	2018	2019	2020	2021*	2022	2023	2024	2025	2026	2027
Capital (Gross)	280	755	569	19	110	251	254	259	136	127
Contributions	(190)	(566)	(199)	(64)	(37)	(80)	(83)	(85)	(43)	(44)
Capital (Net)	90	189	370	(45)	73	171	171	174	93	83

**The net negative capital amount shown in 2021 is due to a timing issue associated with receiving capital contributions from the Bell Canada Fibre-to-the-Home (FTTH) program.*

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Undertaking work to accommodate the use of PUC's distribution equipment for third party joint use is an ongoing activity for PUC, and the historical actual costs associated with this program are shown in Section 3 of this document. Investments under this program can vary substantially year over year depending on the timing and scope of third party developments being undertaken within PUC's service territory. As a result, when referencing historical average expenditures to generate forecast costs under this program, large unique projects are excluded from this. For example, increased costs in 2018-2020 over the historical average are contributable to a Bell Canada Fibre-to-the-Home (FTTH) program where Bell attached new infrastructure to approximately 4,000 PUC poles. This project required significant make ready work to ensure PUC's infrastructure was safe to attach to. Forecast costs are also informed by ongoing conversations with third party communication companies.

6. Investment Priority

This investment program is classed as a high priority since it is a non-discretionary program driven by third party requests and contractual obligations. When joint use 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. Alternatives Analysis

Since this is non-discretionary program, doing nothing is not a viable option as failure to perform the requested work would place PUC in violation of contractual obligations with the third party joint use partners. PUC reviews each application for new/revised attachments on a case by case basis to maximize system operation efficiency and cost effectiveness. Make ready work is reviewed and analyzed to minimize benefit for both parties while ensuring cost effectiveness.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	When partnered with third-party companies, the infrastructure required to support the communities in the region is minimized. Shared conduit structures and shared poles can be used in lieu of standalone systems, leading to less conflict in the field. PUC also reviews each request for new/revised attachments on a case by case basis to maximize system operation efficiency and cost effectiveness.
Customer Value	By permitting third-party companies to attach to PUC's infrastructure in a safe and economical manner, this investment influences communication companies to establish reliable communication systems throughout PUC's service territory and beyond. This contributes towards the economic growth and development of the region. In addition, PUC is able to offset project costs with revenue received from third party companies, thereby reducing the impact to customer rates.
Reliability	Any altering or upgrading of PUC's distribution line equipment to accommodate joint use partners will be completed such that reliability of the system is not negatively affected.
Safety	All work completed under this program considers safety as paramount by designing and installing to USF standards, PUC standards and/or specifics approved by a Professional Engineer.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Mandated Service Obligations* – PUC must meet contractual obligations to joint use partners as per existing Joint Use Agreements. By permitting third-party companies to attach to PUC's infrastructure, PUC is meeting its contractual obligations while also enabling customers throughout PUC's service area and beyond to benefit from the establishment of reliable communication systems.

ii. Secondary Drivers: *Increased Revenue* – PUC is partnered with multiple third-party communication companies in Sault Ste. Marie. All attachment points from third-party companies result in revenue for PUC, which is used to offset project cost and reduce the impact on rates.

iii. Information Used to Justify the Investment: PUC's Joint Use program is driven by contractual obligations and third party requests. Historical average expenditures within this program, excluding any unique large projects, inform forecast costs for this program. PUC also consults with third party communications companies on an ongoing basis to inquire about upcoming plans to ensure PUC is prepared. Additional information on PUC's consultation efforts with telecommunication companies can be found in Section 5.2.2.4 of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: New/revised joint use attachments will be reviewed against CSA, USF and PUC specific standards, and any infrastructure revisions will be completed using USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access.

ii. *Cost-Benefit Analysis*: Options are considered on a case-by-case basis to provide the most practical and cost-effective solution for all parties.

iii. *Historical Investments & Outcomes Observed*: PUC routinely accommodates joint use projects within its service territory. These investments have enabled the successful connection of joint use projects to PUC's distribution equipment, reducing the need for standalone systems and leading to less conflict in the field. These investments have also enabled communication companies to establish reliable communications system throughout PUC's service territory and beyond, which has also contributed towards the economic growth and development within the region.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

CUSTOMER DEMAND – CITY PROJECTS

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Much of PUC's infrastructure is located within the municipal right of way in Sault Ste. Marie and some on the right of way owned by the Ministry of Transportation (MTO). The City of Sault Ste. Marie conducts complete road reconstructions, storm sewer replacement, curb, and asphalt work annually. During these projects, PUC's infrastructure may require relocation/replacement to support the excavation. Due to the Municipal Act and specifically the Public Service Works on Highways Act, PUC is required to relocate/replace infrastructure to support these projects upon request. A cost apportionment is identified in the Public Service Works on Highways Act as 100% material and 50% labour to be absorbed by the utility. The extent of the project areas varies from year to year depending on the City's overall plan and on the nature of PUC's infrastructure in the area being addressed. These projects typically occur between Spring and Fall with majority of the work occurring in early summer in preparation for road excavations.

For the forecast period, PUC assumes infrastructure relocation to accommodate road construction and realignment. In 2023, an underground vault requires relocation to accommodate the construction of Passchendaele Road, multiple pole relocations are required to accommodate a new sidewalk installation on Northern Avenue, and the completion of an overhead to underground relocation in the Bigham Street area is required to accommodate the construction of a Downtown Plaza on land that was previously a municipal right of way. Cost recovery for this program is typically based upon the cost apportionment set out in the Public Service Works on Highways Act.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Key factors that may affect timing include City approvals, roadway schedules, construction needs, and resource constraints. In addition, the schedule for these types of projects is largely dictated by the City/MTO and is therefore outside of PUC’s control.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ ‘000)					Forecast Costs ($ ‘000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	802	390	134	179	90	251	255	324	341	318
Contributions	(205)	(160)	(36)	(59)	(15)	(50)	(52)	(66)	(68)	(69)
Capital (Net)	597	230	98	120	75	201	203	258	273	249

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Undertaking infrastructure relocation/replacement work to accommodate city projects is an ongoing activity for PUC, and the historical actual costs associated with this program are shown in Section 3 of this document. PUC also references the City of Sault Ste. Marie's five-year capital works program to identify the approximate scope of work and requirements for upcoming years. Historical values are used in conjunction with the City's five year plans to generate the forecast costs for this program. Examples of City Projects completed over the historical period are noted in the table below.

Table 2: Historical City Project Examples

Year	City Projects Completed
2018	• Black Road Reconstruction (2nd Line to 3rd Line) – Replacement of entire pole line to accommodate road widening
2019	• Black Road Reconstruction (McNabb to 2nd Line) – Replacement of poles to accommodate road widening. • McNabb Street Storm Sewer Replacement – Replacement of poles and underground infrastructure to accommodate a major storm sewer replacement.
2020	• Bay Street Reconstruction – Road realignment required multiple pole relocations and manhole restorations.
2021	• Downtown Plaza construction – relocation of overhead infrastructure to underground to accommodate the downtown plaza construction on previous municipal right of way. • Third Line East – Relocation of poles to accommodate road alignment and retaining wall installation.

6. Investment Priority

This investment program is classed as a high priority since it is a non-discretionary program driven by third party requests and regulatory compliance. When infrastructure relocation/replacement requests are initiated under this program, they will be balanced with other mandatory system access projects but take priority over other system undertakings and plans.

7. Alternatives Analysis

Since this is a non-discretionary program, doing nothing is not a viable option. PUC is required to relocate/replace infrastructure to accommodate City/MTO projects so that the projects can progress smoothly while minimizing or eliminating any potential safety hazards relating to PUC's infrastructure. For each request received under this program, alternatives are considered on a case by case basis at the time of project implementation, and the most practical solution is pursued considering safety, regulatory, system reliability, economics and customer relations.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

Currently there are no Leave to Construct (LTC) approvals required as part of this program. However, if tasks arise that require LTC approval, PUC will follow required protocol.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	These projects typically have negligible effects on system operation efficiency, however PUC attempts to coordinate projects where possible to optimize efficiency and cost effectiveness. For example, when there is an opportunity to address future concerns, it may be advantageous from a cost perspective to address these needs at the time of relocation rather than returning at a late date to perform the work.
Customer Value	Customers benefit from PUC infrastructure located on municipal road allowances, minimizing cost for PUC to install electrical services. This cost saving will be reflected back to customers.
Reliability	Although the purpose of these projects is not to increase reliability, depending on the age of the assets being relocated/replaced, system reliability may be positively impacted due to the installation of new infrastructure based on current design standards.
Safety	All relocation/replacement work to accommodate City projects consider safety as paramount by designing and installing to USF standards, PUC standards and/or specifics approved by a Professional Engineer.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Mandated service obligations* – This program is mandatory, and the scope and timelines of the infrastructure relocation works required under this program are based on requests put forth by the City/MTO.

ii. Secondary Drivers*: Cost savings* - During relocation, there may be opportunities for PUC to update infrastructure and gain increased life and increased asset value at a reduced cost due to cost apportionment.

iii. Information Used to Justify the Investment*:* PUC is required to relocate infrastructure to support City/MTO projects. PUC references the City of Sault Ste. Marie's five-year capital works program to identify the approximate scope of work and requirements for upcoming years (to date, PUC has received plans up to and including 2023). Additionally, PUC consults with the City and MTO on an ongoing basis to inquire about upcoming plans to ensure PUC is prepared. Additional information on PUC's consultation efforts with the City of Sault Ste. Marie and other municipal stakeholders can be found in Section 5.2.2.2 of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

Demonstrating Accepted Utility Practice: When infrastructure relocation projects are required to accommodate City/MTO projects, all areas revised are reviewed and constructed in compliance with the latest CSA, USF, and/or PUC specific standards. In addition, any infrastructure relocation work presents an opportunity to update dated infrastructure to current standards which can address existing reliability and performance concerns.

i. *Cost-Benefit Analysis*: Project alternatives are considered on a case by case basis to provide the most practical and cost-effective solution for all parties.

ii. *Historical Investments & Outcomes Observed*: PUC routinely undertakes infrastructure relocation projects to accommodate City/MTO projects within its service territory. These investments have helped to ensure the successfully implementation of City/MTO projects in the past by eliminating any safety hazards relating to PUC's infrastructure. In addition, historical work completed under this program has also enabled PUC to update its infrastructure and gain increased life and increased asset value at a reduced cost due to cost apportionment.

iii. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. INNOVATION

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

REVENUE METERS

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC owns and operates approximately 34,250 revenue meters, installed on its customers' premises for the purpose of measuring electric consumption and demand of connected load for the purpose of billing. All existing residential and general service (GS) customers (< 50 kW) were equipped with smart meters between 2009 and 2010.

This program includes expenditures related to the supply, installation and maintenance of revenue meters installed at each customer service point for retail settlement and billing purposes for all customers connected to PUC's distribution system. Revenue meters have four primary drivers, including (a) new meters for new customers, (b)) replacement of failed units, (c) reliability (elimination of meter types that have history of poor reliability) and (d) standardization.

The metering services included within this program are divided across 3 main sub-programs:

- **General:** This sub-program includes the installation of meters for new customers, replacement of faulty or expired meters, and the maintenance and upgrade of supporting metering infrastructure over the 2023-2027 forecast period. All new meters installed or replaced are 'iConA' remote disconnect smart meters. Meters to be purchased by PUC are forecast based upon historical information, quantity of meters expected to reach their seal expiry date, as well as the forecast new customer connections. PUC is looking to purchase approximately 400 new meters on average each year over the forecast period. This sub-program also includes costs associated with the purchase of smaller items that are used for maintenance and repairs, including but not limited to, meter seals, meter rings, disconnect sleeves, and metering wire. The number of meters and supporting metering infrastructure required for purchase will be reviewed each year by PUC to ensure the appropriate amounts are purchased.
- **Compliance Testing & Resealing:** In accordance with Measurement Canada Guidelines, PUC is required to reseal meters at specified intervals to ensure that a customer's electricity usage is metered accurately. Once a seal expires, the meter can no longer be used for billing purposes and must either have its seal period extended via compliance testing, or be replaced. Between 2023 to 2027, approximately 27, 968 of PUC's residential smart meters will subjected to testing by Measurement Canada using compliance sampling methods. This method sees compliance sample groups of approximately 1,000 meters that are tested. If the units pass the sample testing, their seal period will be extended and they can remain in service for the number of years as determined by the statistical sampling process. Additionally, in this same period 454 meters will expire and will need resealing. If the units fail sample testing, they will have to be removed from service and replaced by the end of the year that they are sampled in.
- **MIST Conversion for GS>50kW Customers:** A Metering Inside the Settlement Timeframe (MIST) is an interval meter from which data is obtained and validated within a designated settlement timeframe. In accordance with the DSC, PUC is required to install MIST meters for all general service customers that have a monthly average peak demand during a calendar

year of over 50 kW (i.e., GS > 50 kW). PUC is planning to complete the conversion of 78 existing GS>50 kW customers to MIST meters in years 2024 and 2025.

Since these investments are required by the Distribution System Code (DSC) and Measurement Canada guidelines, they are considered non-discretionary. By implementing this program, PUC 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.

2. TIMING

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: The timing of the metering services included in this program are highly dependent on customer requests for new services as well as on the timing of metering system upgrade cycles. Other factors that might affect timing include material and resource constraints.

3. HISTORICAL AND FORECAST CAPITAL EXPENDITURES

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	174	62	500	208	173	207	509	527	243	255
Contributions	0	0	0	0	(20)	(20)	(21)	(21)	(22)	(22)
Capital (Net)	174	62	500	208	153	187	488	506	222	233

Note: The forecast capital contributions are expenditure that is collected from general customers where instrument transformers are required to be used with the primary metering. These are purchased by the customers as per PUC's Conditions for Service. The reason there are no capital contributions from 2018-201 is that no primary customer connections were carried out.

4. ECONOMIC EVALUATION (EXPANSION PROJECTS)

This is not applicable.

5. COMPARATIVE HISTORICAL EXPENDITURE

Metering services are ongoing annual expenditures. In the previous five historical years, PUC has purchased 1,590 meters to be used for new meter installs or meter replacements as part of this program. The following table shows the number of meters purchased each year. Meters are purchased into inventory and exact installation timing depends upon the needs of customers.

Table 2: Historical Number of Meters Purchased

	2018	2019	2020	2021	2022
Number of Meters Purchased	782	413	215	50	130

It is also noted that for the historical period 2018-2021 that there were no capital contribution amounts received although it is regularly budgeted for. This reflects the fact that there were no larger or primary customer service connections in which the customer is required to purchase their own instrument transformers in alignment with PUC Conditions of Service.

PUC considered historical expenditure, existing meter information, forecast customer needs, inflation, and other supply chain and material cost factors to generate forecast costs under this program.

6. Investment Priority

This investment program is classed as a high priority due to the obligation to connect new customers and the need to comply with mandated service obligations as defined by the DSC and Measurement Canada.

7. Alternatives Analysis

This investment is non-discretionary. No alternatives were considered since 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 settlement data.

8. Innovative Nature of the Project

There is nothing innovative in this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	To enable cost efficiencies, PUC will look to purchase the new meters and associated equipment in bulk. Additionally, through addressing meters that are expiring, PUC will have reduced the number of meters that would be susceptible to unexpected failure and therefore reduce the cost for having to reactively repair these meters. Metering technology also supports the efficient and effective operation of PUC's system, and the metering services under this program will increase operational efficiency by reducing the number of manual reads.
Customer Value	For new meter installations as part of customer connection requests, the primary benefit for the customer is access to the

Primary Criteria for Evaluating Investments	Investment Alignment
	distribution system thereby meeting customers' power needs. Additionally, by upgrading and renewing existing meters that are expiring, this will ensure that customer meters continue functioning, capturing accurate electricity usage, and therefore enabling PUC to produce an accurate bill. Customer also have the ability to monitor their historical consumption through the PUC Customer app.
Reliability	Revenue meters have no impact on reliability performance on the feeder or at the customer location. However, by installing new meters that are up to current standards, this ensures that the reliability of the meters themselves continues to be maintained, thus enabling a reliable source of billing settlement data. All meters have last gasp functionality which in turn enables emergency response and outage restoration activities more effectively.
Safety	New meters will meet all safety standards.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Mandated Service Obligations* - The main driver for this program is PUC's obligation related to metering services as defined by the DSC and Measurement Canada. PUC is obligated to install and maintain meters at all customer connection points from both residential and commercial customers. By accommodating new connection requests and by replacing meters that have expired with new meters, PUC ensures that it complies with its obligations to provide, install, and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distribution system.

ii. Secondary Drivers*: Failure Risk* - By addressing expired meters, this reduces the risk of the meters failing and ensures the continued delivery of reliable and accurate bills.

iii. Information Used to Justify the Investment*:* New meter installations are mandatory investments arising from customer requests for new service connections, therefore customer requests are the source of information used to justify the new meter installations. PUC also collects and tracks data on its existing meters, and this information is used to determine when a meter requires testing, resealing or replacing.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital *investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).*

i. *Demonstrating Accepted Utility Practice*: PUC plans and executes its metering program to accommodate customer requests and comply with regulations. All new meters installed comply with the latest standards and regulations, and all metering services will be carried out in accordance with PUC's standards and practices.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Historical Investments & Outcomes Observed:* This historical costs and number of meters replaced during the historical period are detailed in sections 3 and 5 in part A of this document. Through its metering program, PUC has been able to continue to accurately bill customers.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing innovative in this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

UNPLANNED OH RENEWAL (FORCED)

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

The unplanned overhead (OH) renewal program is intended to cover costs associated with capital asset renewal from unplanned occurrences, typically resulting from weather related occurrences and/or vehicle accidents. When an unplanned occurrence materializes, PUC reviews the situation and determines whether a repair (maintenance budget) is adequate or if a complete replacement of the asset is warranted. When a complete replacement is warranted, PUC will replace the asset to today's standards, where feasible.

The number of customers affected by each failure is dependent on the location of the failure and the assets affected. For example, if a single distribution transformer fails, the customers affected should be limited to approximately 15. If the asset failed is a distribution pole supporting the sub transmission line (34.5kV), the customers affected could be up to 50% of the City. The number of customers immediately affected is not within PUC's control. PUC attempts to limit the number of customers that experience extended outages by switching, repairing and/or replacing assets.

For the forecast period, PUC has estimated the average number of assets that may need replacement based on historical failure information. The following table highlights the estimated number of replacements based on asset type. To be clear, as this is a reactive program, it is hard to predict the exact and type of assets that will need to be replaced on an unplanned basis. These figures are provided based on historical information and will likely be change.

Table 1: Estimated Number of Replacements by Asset Type

Asset Class	2023	2024	2025	2026	2027
Poles	15	15	15	15	15
Pole mount transformer	15	15	15	15	15
Fused switches	4	4	4	4	4
Disconnect switches	1	1	1	1	1

2. Timing

i. Start Date: January 2023

ii. In-Service Date: 2023 - 2027

iii. Key factors that may affect timing: Forced (reactive) replacements are prioritized and therefore no factors should affect timing.

3. Historical and Forecast Capital Expenditures

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	244	357	304	457	293	314	318	324	341	318
Recoverable[1]	74[2]	(156)	(163)	(86)	(37)	(38)	(39)	(40)	(41)	(41)
Capital (Net)	318	201	141	371	256	276	279	284	300	277

[1] The recovery rate is around 15% from vehicle accident poles.
[2] The positive removal amount in 2018 is the reversal of some uncollectable invoicing from prior years.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PUC compares historical values for each category to budget for a recent average. As this budget is dependent on externally driven aspects such as weather and traffic accidents, the expenditures are considered on an annual basis and become difficult to predict. Between 2019 and 2021, 52 poles and 45 pole mount transformers were replaced, with total costs around $734,000 including recoverable, which averages around $245,000 per year.

6. Investment Priority

This is a high priority investment and falls under non-discretionary category. Projects under this investment are on top of PUC's list because they arise from system outages and safety concerns. Using PUC's prioritization process, this project ranks 1st out of 11.

7. Alternatives Analysis

PUC considered the following options:

- **Option 1: Proactive Replacement of Overhead Assets** - Although PUC tests assets and performs regular system inspections to understand where majority of concerning assets are located, completely eliminating system outages through planning is not possible. External factors such as weather or accidents can cause unplanned outages and reactive measures are required to respond to those situations, therefore this is not a viable option.

- **Option 2: Reactive Repair/Replacement of Overhead Assets** - There are no other practical alternatives to be considered because of the reactive and high priority nature of these projects. It is essential to replace affected overhead assets as soon as possible to ensure safety and access to reliable electricity. A reactive approach to safe asset failures extends the assets useful life to the point of failure. Balancing the value to the extended life and the incremental costs due to the reactive approach is considered to optimize replacements.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	This is not applicable.
Customer Value	Through this investment, customers will have reduced outage times and safety concerns managed in a timely fashion.
Reliability	This investment has a significant impact on reliability performance. Although these projects do not impact the frequency of outages (SAIFI), they do limit the size of the extended outage and reduce the duration of outages (SAIDI, CAIDI).
Safety	Safety is a driving factor for this investment. By attending the site, making it safe, and replacing the failed infrastructure, PUC reduces hazards for both the public and the workers. Final installations are then completed as per CSA, USF and/or PUC specific standards.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Failure risk* - When a fault occurs, it typically causes an outage for several customers. PUC strives to provide a reliable system for all its customers by attending to the site as soon as possible.

ii. Secondary Drivers: *Safety* - Safety to the public and workers when a fault occurs in the system is a driving investment factor. Although the system is protected through fusing, reclosers, relays, and breakers, it is imperative that PUC assesses the site to ensure safety.

iii. Information Used to Justify the Investment*:* This investment is required to provide a safe and reliable electrical system to customers and mitigate the risk of PUC's reliability statistics from decreasing by limiting the duration of outages.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: Emergency replacement of assets are constructed in accordance with USF and/or PUC specific standards, which are in line with industry standards allowing third parties reasonable access. Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or PUC standards. Final installation will be completed as per CSA, USF and/or PUC specific standards.

ii. *Cost-Benefit Analysis:* There are no other cost-effective and practical alternatives to this investment.

iii. *Historical Investments & Outcomes Observed:* Although PUC compares historical values for each category to budget for a recent average number of unplanned outages, it is difficult to accurately project due to the unpredictable nature of the outages. In the past, these projects have had minimal long-term effects on O&M costs. Asset replacements due to failure do not require significant O&M attention in the future.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

UNPLANNED UG RENEWAL (FORCED)

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

The unplanned underground (UG) renewal program is intended to cover costs associated with capital asset renewal from unplanned occurrences, typically resulting from failed underground and/or pad mounted assets. When an unplanned occurrence materializes, PUC reviews the situation and determines whether a repair (maintenance budget) is adequate or if a complete replacement of the asset is warranted. When a complete replacement is warranted, PUC will replace the asset to today's standards, where feasible.

Impacts to customer vary on a case-to-case basis. Some examples are extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC responds to each case effectively with the goal of minimizing the duration of outages for all customers.

For the forecast period, PUC has estimated the number of assets that might fall under the forced underground renewal program. To be clear, as this is a reactive program, it is hard to predict the exact and type of assets that will need to be replaced on an unplanned basis. These figures are provided based on historical information and will likely be change.

Table 1: Estimated Number of Replacements by Asset Class

Asset Class	2023	2024	2025	2026	2027
Pad mount transformer	6	6	6	6	6
Submersible transformer	7	7	7	7	7

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Forced (reactive) replacements are prioritized and therefore no factors should affect timing.

3. Historical and Forecast Capital Expenditures

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	208	303	344	388	322	376	382	388	409	382
Contributions	(17)	(2)	0	(19)	0	0	0	0	0	0
Capital (Net)	191	301	344	369	322	376	382	388	409	382

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PUC compares historical values for each category to budget for a recent average. Since this budget is dependent on unexpected failures, the expenditures are considered on an annual basis and become difficult to predict. Limited investment into aging underground infrastructure result in increased forced replacement and maintenance costs.

Between 2019 and 2021, five (5) mini pad, 13 pad mount, and 21 submersible transformers were replaced, for a project total cost of approximately $786,000, making the average yearly cost of forced underground renewal projects to be around $262,000.

6. Investment Priority

This is a high priority investment and falls under non-discretionary category. Using PUC's prioritization process, this project ranks 1st out of 11. Projects under this investment are on top of PUC's list because they arise from system outages and safety concerns.

7. Alternatives Analysis

PUC considered the following options:

- **Option 1: Proactive Designing of Underground Assets** - Proactively designing all potential failure assets or designing asset on the spot after the failure is not practical and therefore not a viable option.
- **Option 2: Reactive Repair/Replacement of Underground Assets** - There are no other practical alternatives to be considered because of the reactive and high priority nature of these projects. It is essential to repair/replace affected assets as soon as possible to ensure safety and access to reliable electricity. This investment also has some cost-savings opportunities for PUC. A reactive approach to safe asset failures extends the assets useful life to the point of failure. Balancing the value to the extended life and the incremental costs due to the reactive approach is analysed to optimize replacements.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	This is not applicable.
Customer Value	Through this investment, customers will have reduced outage times and safety concerns managed in a timely fashion.
Reliability	This investment has a significant impact on reliability performance. Although these projects do not impact the frequency of outages (SAIFI), they do limit the size of the extended outage and reduce the duration of outages (SAIDI, CAIDI).
Safety	Safety is a driving factor for this investment. By attending the site, making it safe, and replacing the failed infrastructure, PUC reduces hazards for both the public and the workers. Final installations are then completed as per CSA, USF and/or PUC specific standards.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Failure risk* - When a fault occurs, it typically causes an outage for several customers. PUC strives to provide a reliable system for all its customers by attending to the site as soon as possible.

ii. Secondary Drivers: *Safety* - Safety to the public and workers when a fault occurs in the system is a driving investment factor. Although the system is protected through fusing, reclosers, relays, and breakers, it is imperative that PUC assesses the site to ensure safety.

iii. Information Used to Justify the Investment: This investment is required to provide a safe and reliable electrical system to customers and mitigate the risk of PUC's reliability statistics from decreasing by limiting the duration of outages.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital *investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).*

i. *Demonstrating Accepted Utility Practice*: Emergency repair and replacement of assets are constructed in accordance with USF and/or PUC specific standards, which are in line with industry standards allowing third parties reasonable access. Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or PUC standards. Final installation will be completed as per CSA, USF and/or PUC specific standards.

ii. *Cost-Benefit Analysis:* There are no other cost-effective and practical alternatives to this investment.

iii. *Historical Investments & Outcomes Observed:* Although PUC compares historical values for each category to budget for a recent average number of unplanned outages, it is difficult to accurately project due to the unpredictable nature of the outages. In the past, these projects have had minimal long-term effects on O&M costs. Asset replacements due to failure do not require significant O&M attention in the future.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

OH RENEWAL – TRANSFORMERS (PCBS)

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC owns, operates and maintains 1,850 pole mounted transformers, all of which are oil filled. Historically, a chemical compound known as a polychlorinated biphenyl (PCB) was widely deployed in dielectric and coolant fluids in the manufacturing of oil filled electrical apparatus. However, this manufacturing practice was discontinued when it became evident that PCBs build up in the environment and exposure to high levels can cause harmful health effects.

In 2008, Environment Canada enacted Federal Regulation *SOR 2008-273 – PCB Regulations* which dictates requirements to replace equipment with oil containing PCBs by various dates depending on the PCB concentration. The regulations set a deadline of December 31, 2025 to eliminate concentrations of PCB's greater than 50 ppm in pole mounted, oil filled, electrical transformers. This project addresses the removal and replacement of the remaining overhead pole mounted transformers with PCB concentrations greater than 50 ppm within PUC's distribution system.

PUC undertook a PCB transformer testing program in 2020/2021 to determine the number of remaining pole mounted transformers within its distribution system with PCB concentrations greater than 50 ppm. To date, approximately 73% (1,350 of 1,850) of PUC's transformers have been inspected and tested, and PUC has confirmed that 11% (145) of transformers have PCB concentrations greater than 50 ppm. PUC is planning to inspect and test the remaining transformers over the period from 2023 to 2024, however based on an extrapolation of the testing results, PUC anticipates that approximately 200 transformers (i.e., 11% of the total pole mount transformer population) will have PCB concentrations greater than 50 ppm and therefore need to be replaced by December 2025. As a result, PUC is planning to replace approximately 67 PCB-contaminated transformers annually between 2023 to 2025 with new standardized transformer equipment in order to comply with PCB regulations.

To take advantage of timing, cost and resource efficiencies, PUC is also planning to replace end-of-life poles, which are associated with the transformer forecast to be replaced, as part of this project.

By implementing this project, PUC will ensure continued compliance with environmental legislation while also mitigating the health, environmental and safety risks associated with PCB contamination >50 ppm.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2025

iii. Key factors that may affect timing: Material and resource constraints may affect timing, however PUC intends to complete designs and order materials as required. Due to the significant delay on transformer delivery (quoted up to 2 year delivery time), this may impact the program and how PUC is able to meet the December 31, 2025 deadline.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	0	0	0	0	0	711	721	734	0	0
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	711	721	734	0	0

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

As part of this project, the average pole mount transformer replacement cost including a portion of pole replacements is on average $8,500 per location. Since this is a new separate project for PUC, there is no direct comparative historical expenditure information.

However, PUC has replaced pole mounted transformers historically as part of other projects or programs, at an average cost of $5,000 per replacement for the transformer only or $10,000 when the pole requires replacement.

6. Investment Priority

This investment is classed as a high priority due to the obligation to eliminate concentrations of PCB's greater than 50 ppm in electrical transformers by December 31, 2025, in accordance with the Federal PCB Regulations.

7. Alternatives Analysis

This investment is non-discretionary. No alternatives are considered, since failure to remove PCB contaminated distribution line equipment would place PUC in violation of Federal PCB Regulations and result in increased public health, environmental and safety risks.

8. Innovative Nature of the Project

There is nothing innovative in this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Planned replacement of these pole mounted transformers rather than reactive replacement at the time of a leak or catastrophic failure can usually be organized as part of regular work and therefore not subject to overtime premiums. Planned replacements will also eliminate the risk of any additional work or costs associated with potential PCB contamination.
Customer Value	The potential health and safety hazards to customers and the public associated with PCB transformers are being mitigated via the execution of this project. Remediation of PCB contamination is costly and therefore minimizing the exposure provides additional long term customer value.
Reliability	This project will replace old PCB contaminated transformers with new equipment. As the existing transformer is beyond its useful life, the new transformer should improve reliability. In addition, the replacement of EOL poles as part of this project will also improve the overall reliability of the system.
Safety	The potential health, environmental and safety risks associated with PCB transformers are being mitigated via the execution of this project.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Mandated Obligations Mandated Service Obligations* – the main driver for this project is the Federal Regulation SOR 2008-273 which dictates that all pole mounted equipment with oil containing PCBs in concentrations of 50 ppm or greater must be removed from service by 2025.

ii. Secondary Drivers: *Failure Risk* – By addressing the contaminated pole mounted transformers, this eliminates the risk of these transformers leaking or failing and ensures PUC's ability to guard worker, public and environmental safety and while maintaining system reliability. All transformers being replaced within this program are beyond their useful life and are subject to failure. Replacement will help improve reliability.

iii. Information Used to Justify the Investment*:* PUC undertook a PCB transformer testing program in 2020/2021 to determine the number of remaining pole mounted transformers within its distribution system with PCB concentrations greater than 50 ppm. Approximately 73% of PUC's transformer population has been inspected and tested to date, and the results were used to identify the transformers that require replacement by the December 31, 2025 deadline.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: PUC is executing this project to comply with regulations. All new pole mounted transformers purchased will comply with the latest standards and regulations, and all installations will be carried out in accordance with PUC's standards and the *ON Reg. 22/04* to ensure no undue safety hazards. The transformers will be replaced with PUC's current standards for pole mounted transformers used throughout PUC's system.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Historical Investments & Outcomes Observed:* Pole mounted transformers have been replaced historically as part of other projects or programs, but this is the first project focused on eliminating pole mounted transformers. Historical information from other projects has been used to create a program budget. Estimates will be reviewed for accuracy during detailed design.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that *allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.*

There is nothing innovative in this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

OH RENEWAL – VOLTAGE CONVERSION

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Approximately 30 years ago, PUC started a program to gradually upgrade its distribution system from 4.16 kV to 12.47 kV. When the existing 4.16 kV infrastructure reaches the end of its service life, rather than like for like replacement of 4.16 kV rated equipment with 4.16 kV rated equipment, the voltage is upgraded to 12.47 kV, which results in greater operating efficiency. A vast majority of the distribution system has already been upgraded to 12.47 kV and at present relatively small pockets of service area with 4.16 kV network remain.

PUC has approximately 22 km of 4.16 kV circuits and two 4.16 kV distribution stations (Substations #4 and #5) remaining in service. Most of the remaining distribution infrastructure operating at 4.16 kV is at the end of its service life and the poor condition of equipment has been resulting in frequent equipment failures with adverse impacts on reliability. Maintaining a distribution system with two operating voltages has also resulted in duplication of lines and economic inefficiencies due to system energy losses.

As part of this Voltage Conversion program, PUC is proposing to complete its long standing voltage conversion initiative by retiring the remaining network equipment operating at 4.16 kV from the grid. This includes replacing two sections of 4.16 kV circuits with 12.47 kV circuits (detailed below), disconnecting Substations #4 and #5, and removing all remaining 4.16 kV circuits from service. In the 2023 Test Year, the following activities are planned:

- **Railway Tracks (Elizabeth to Simpson):** This project includes the replacement of *1,400 m* of overhead end of life 4.16 kV circuit with 12.47 kV circuit from Elizabeth Street to Simpson Street. The circuit is primarily 3phase and will be reduced to single phase further increasing reliability and reducing operations and maintenance costs. There are eighty-two (82) customers immediately impacted by the project.

Figure 1: Railway Tracks (Elizabeth to Simpson) – Project Area

Figure 2: Typical Pole in Project

- **Pim (Ontario to Sub 4):** This project includes the replacement of *765 m* of overhead end of life 4.16 kV circuit to 12.47 kV circuit from Ontario Street to Substation 4. Although this project does not directly service any customers, removal of the existing 4.16 kV line will permit PUC to decommission Substation #4 and reduce reliability concerns and ongoing operations and maintenance costs.

Figure 1: Pim Street (Ontario to Sub 4) - Project Area

Figure 2: Typical Pole in Project

- **Installation of 34.5kV switch point:** This project includes the installation of a new 34.5 kV switching point in an area adjacent to Substation #4 (shown in Figure 5 below). The installation of a 34.5 kV switching point will provide PUC the same level of switching flexibility currently available in the 34.5 kV sub-transmission system.

Figure 3: 2012 Photo of Area Adjacent to Substation #4

PUC is also planning to disconnect Substations #4 and #5, which will increase safety, reliability and reduce operation and maintenance costs.

Completion of PUC's long standing voltage conversion project during this filling period is expected to bring benefits in a number of ways. Firstly, these remaining circuits once transferred over from 4.16 kV to 12.47kV, will allow for the connection of DER as the newer 12.47 kV feeders include the necessary protection systems to support their connection. Secondly, the elimination of multi-circuit distribution lines along many streets eliminates the need to stock multiple types of equipment and should lead to a less complex and better hardened system better able to withstand more severe wind and ice loading weather conditions expected with climate change. Additionally, removal of the remaining 4.16 kV distribution lines will permit the disconnection of the two remaining 4.16 kV substations improving system safety and reliability. Furthermore, the reduction in electrical losses from retiring the remaining 4.16 kV infrastructure and with the move to higher voltage are expected to bring advantages from an environmental perspective.

Although Substations #4 and #5 will be disconnected during this DSP period, decommissioning of the substations has been deferred to the next cost of service period.

2. TIMING

i. Start Date: January 2023

ii. In-Service Date: December 2023

iii. Key factors that may affect timing: Project implementation may be delayed depending on unplanned or higher priority work arising, resulting in resource constraints.

3. HISTORICAL AND FORECAST CAPITAL EXPENDITURES

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	257	557	296	640	663	864	0	0	0	0
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	257	557	296	640	663	864	0	0	0	0

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PUC has extensive historical information on voltage conversion projects and projects of similar nature. Using this information, PUC can reasonably estimate each project without a detailed design being completed beforehand. For example, according to 2017 estimates, the conversion project along McDonald (Pine to Sub 4) cost around $100,000, whereas the McDonald (Lake to Moluch) project costs were around $210,000. Since each project is unique (e.g., some projects require complete rebuilds of the pole lines while others are mostly removal with some replacements, some projects have vehicle accessibility while others are in difficult to access rear lots, etc.), average costs are difficult to identify.

6. Investment Priority

Using PUC's prioritization process, this project is ranked 3rd out of 11 projects. In the prioritization process, project interdependence is the main contributor to the ranking of the project, meaning that not proceeding with this project will negatively impact the ability to complete other future planned work. It is important to complete the remaining conversion projects in order to simplify, standardize and improve the overall performance and efficiency of the distribution system.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Do Nothing** – System assets planned for replacement under this program are nearing or beyond their anticipated lifespan, making them unreliable and unsafe in some situations. Replacing these assets is essential in maintaining a safe and reliable distribution system, therefore doing nothing is not an option. Since most of the conversion and replacement has already taken place, it is important to complete the remaining conversion projects.
- **Option 2: Voltage Conversion and Station Replacement** – This option includes retiring the remaining network equipment operating at 4.16 kV from the grid, upgrading all the remaining line sections to 12.47 kV, and replacing Substation 4 with a 34.5 kV switch point. This is the preferred option as it will enable PUC to replace end of life poor condition equipment with new standardized equipment while also reducing electrical losses, eliminating multi-circuit distribution lines, and enabling future opportunities for the connection of DER and EVs.

8. Innovative Nature of the Project

Although voltage conversion projects are not considered innovative for PUC, once these circuits are transferred over from 4.16 kV to 12.47 kV, this will allow for the connection of distributed energy resources (DER) and electric vehicle (EV) charging as the newer 12.47 kV feeders include the necessary protection systems to support their connection.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that *it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).*

Currently there are no Leave to Construct (LTC) approvals required as part of this program. However, if tasks arise that require LTC approval, PUC will follow the required protocol.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Upgrading 4.16 kV rated equipment to 12.47 kV equipment will result in greater operating efficiency, reduced power losses, and standardized equipment allowing for purchasing efficiencies. It will also eliminate the last of many complex multi-circuit distribution lines and the need to stock multiple types of equipment.
Customer Value	Customers will benefit from continued access to safe and reliable electricity. The conversion will also enable future opportunities for DER and EV charging.
Reliability	This investment will have a positive impact on system reliability since old poor condition assets are being replaced with new assets with lower failure risk.
Safety	To convert voltages, many transformers will require replacement. The framing, inclusive of separations on existing poles may be well below current standards. In order to ensure separations are achieved and working space is considered, many poles beyond their useful life will require replacement. In replacing poles, safety is increased for both the work (working space) and the public (new asset). Additionally, removal of the 4.16 kV distribution lines will permit retiring of the two remaining 4.16 kV substations improving system safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Safety & Reliability* - Most of the remaining distribution infrastructure operating at 4.16 kV is at the end of its service life and the poor condition of equipment has been resulting in equipment failures with adverse impacts on reliability. The two remaining 4.16 kV substations have surpassed their useful life creating increased safety and reliability risks. Decommissioning the existing substations is not feasible without the complete system conversion. With stations being replaced with higher distribution voltage to meet industry standards, the system will be more dependable, and customers will have access to reliable electricity.

ii. Secondary Drivers: *Cost effectiveness* - The conductors are currently operating at a lower voltage (4.16 kV vs. 12.47 kV), which requires a larger amount of current to be fed through conductors to supply the same amount of power. Voltage conversion will result in a reduction in losses. Additionally, standardizing material allows PUC to store less material, requiring less inventory.

iii. Information Used to Justify the Investment: PUC's Voltage Conversion Program is a long standing program that is informed by PUC's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP). As detailed in PUC's ACA report included in Appendix H of the DSP, PUC has approximately 22 km of 4.16 kV line and two 4.16 kV distribution stations in service (Substations 4 and 5). Most of the remaining distribution infrastructure operating at 4.16 kV is at the end of its service life and the poor condition of equipment has been resulting in frequent equipment failures with adverse impacts on reliability. By allowing poor condition and end-of-life equipment to be replaced, this investment prevents the power supply reliability from degrading below PUC's targets. The planned replacement and conversion projects are essential in maintaining a reliable distribution system for the customers.

3. INVESTMENT JUSTIFICATION

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: Replacements will be constructed using USF standards, PUC standards, and/or specifics approved by a Professional Engineer.

ii. *Cost-Benefit Analysis*: There are no other practical and cost-effective alternatives for projects under this investment that provide the same level of benefits to customers.

iii. *Historical Investments & Outcomes Observed*: PUC has completed several voltage conversion projects historically 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:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

Although voltage conversion projects are not considered innovative for PUC, once these circuits are transferred over from 4.16 kV to 12.47 kV, this will allow for the connection of DER and EV charging as the newer 12.47 kV feeders include the necessary protection systems to support their connection.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

OH RENEWAL – RESTRICTED CONDUCTOR

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor (i.e., small and constructed of copper), the conductor becomes elongated and brittle over years of use, making it prone to failure through breaking. One of the consequences is an increased frequency and duration of outages. Additionally, because of its potential to break with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenergized state. The time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs.

When #6 is replaced, it is upgraded to #2 aluminum conductor steel-reinforced cables (#2ACSR), which are high-capacity and high-strength conductors. Generally, along with restricted conductors, any poor condition and end of life assets such as poles, cross arms, pole mount transformers, fused switches and/or disconnect switches are also addressed at the same time to gain economies of scale.

The typical age of installation in areas where #6 conductor is present is typically mid 1970's or earlier, making the assets 50 years or older. This is generally why restricted conductor projects involve more than simply replacing the conductor, resulting in efficient long-term solution and economies of scale. The following table highlights the areas with #6 conductor that are planned to be addressed over the forecast period as part of this restricted conductor replacement program:

Table 1: Proposed Restricted Conductor Replacements

Year	Areas Addressed for Restricted Conductor Replacement
2023	Bloor Street West, Langdon/Sydenham/Cheshire/Henry/Kingsford/Murton Phase 1
2024	Langdon/Sydenham/Cheshire/Henry/Kingsford/Murton Phase 2, Herkimer/Victoria/Hess, Brule Road, Old Goulais Bay Rd.
2025	St. Basils Dr/Walters St., Fournier Rd./River Rd.
2026	Nettleton Street, 4th Line E, Fish Hatchery Road/Landslide Road, Trunk Rd. (East of Fournier)
2027	None

The two key projects planned for the 2023 Teat Year are described further below:

- **Bloor Street West:** This project includes the replacement of 300 m of #6 copper overhead primary conductor located at Bloor Street West, immediately affecting 16 customers. The area is front lot accessible.

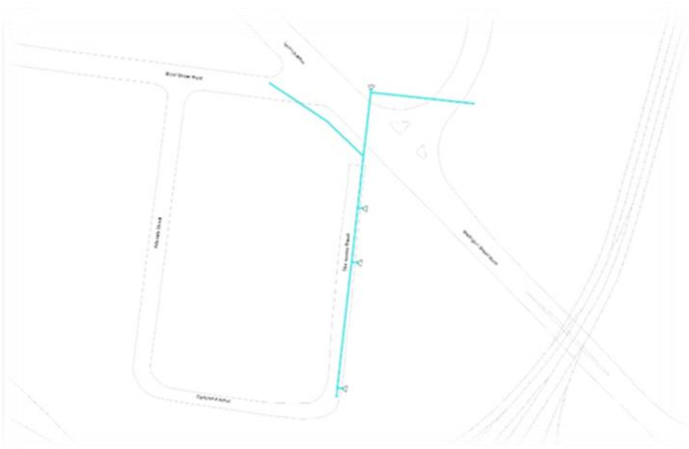


Figure 1: Bloor Street West - Project Area

Figure 2: Typical Pole in Project

- **Langdon/Sydenham/Cheshire/Henry/Kingsford/Murton Phase 1:** This project includes the replacement of 980 m of #6 copper overhead primary conductor located on multiple streets in the area of Langdon Road. The area is front lot accessible immediately affecting 95 customers.

Figure 3: Langdon Road Area - Project Area

Figure 4: Typical Pole in Project

Completing the proposed work under this program will eliminate safety risks associated with the #6 conductor, while also having a positive effect on reliability and system operation efficiency.

2. Timing

i. Start Date: January 1, 2023

ii. In-Service Date: December 31, 2023

iii. Key factors that may affect timing: Project implementation may be delayed depending on unplanned or higher priority work arising, resulting in resource constraints.

3. Historical and Forecast Capital Expenditures

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	930	406	620	222	878	362	1,288	517	834	0
Contributions	0	(14)	(52)	0	0	0	0	0	0	0
Capital (Net)	930	392	568	222	878	362	1,288	517	834	0

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Using historical information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC can reasonably estimate each project without a detailed design being completed beforehand. However, the costs per length on a project-by-project basis are extremely variable and are dependent on many factors. Factors include vehicle accessibility, condition of pole and associated infrastructure and weather conditions during construction. Due to this, it difficult to utilize a single project or even a single year to analyse costs.

6. Investment Priority

Using PUC's prioritization process, this project is ranked 4th out of 11. In the prioritization process, Public Safety is the main contributor to the ranking of the project. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service but working around restricted conductor can be handled through work procedures until all restricted conductors can be removed.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Do Nothing** – Although it is possible to work around a restricted conductor temporarily, not removing it will cause the project to be extended, resulting in increased associated operation and repair costs. Additionally, not replacing restricted conductors can pose serious safety risks for workers and the public. Therefore, this is not a practical and viable option.
- **Option 2: Replacement of Restricted Conductors & Associated Infrastructure** – This option will remove restricted wire and generally replace it with new #2ACSR primary conductor. This option also optimizes mobilization costs to replace aged infrastructure at the same time limiting multiple visits and additional outages to customers. This is the preferred option as it will enable PUC to eliminate the safety risks associated with this conductor, while also having a positive effect on reliability and system operation efficiency.
- **Option 3: Replacement of Restricted Conductors** – This option will remove restricted wire and generally replace it with new #2ACSR primary conductor. This option reinsulates and replaces conductor like-for-like. Although the safety risk of the conductor is removed, the safety and reliability risks of the aged infrastructure remains with additional mobilization costs required. As a result, this option was discarded.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

Currently there are no Leave to Construct (LTC) approvals required as part of this program. However, if tasks arise that require LTC approval, PUC will follow the required protocol.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Removing the restricted conductor will have a positive effect on system operation efficiency since it will reduce the system downtime and the inconvenience associated with routinely isolating these circuits when work is required. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are also reviewed and addressed if required. This leads to asset management efficiencies and cost savings for PUC.
Customer Value	Customers benefit from a safer, more reliable system and more cost effective electrical distribution system. Reducing downtime of PUC's system also contributes positively towards economic development in the region.
Reliability	Removal of restricted conductor and replacement of associated infrastructure that is in poor condition and beyond its useful life will reduce the risk of outages and downtime, leading to a more reliable system.
Safety	Safety is a driving factor for this investment. Removal of restricted conductor eliminates the risks associated with routinely isolating circuits to provide adequate worker safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Safety* – Safety is the primary driver for this project. The restricted conductor can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third-party contractors are working on infrastructure attached to PUC's poles with restricted conductor present as additional forces to the conductor further expose failure points. Eliminating the restricted conductor will eliminate the safety hazards associated with this equipment and make the workplace safer.

ii. Secondary Drivers: *Economic Efficiency* - PUC's current practice for work on poles containing restricted conductor is to take an outage if staff, contractors, or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

iii. Information Used to Justify the Investment: It is common knowledge and well documented across the utility sector that the #6 conductors, over time, become brittle and present a safety risk if not adequately managed through costly customer impactive work methods. This is a known risk that is being proactively addressed through implementation of this program.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: Given the known safety risks associated with these small copper conductors, most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists. Replacements will also be constructed using USF standards, PUC standards, and/or specifics approved by a Professional Engineer.

ii. *Cost-Benefit Analysis:* Although doing nothing may be temporarily possible using work arounds, this can lead to increased risk and more expensive procedures in the near future. Therefore, there are no other practical and cost-effective long-term alternatives available to address the remaining restricted conductor in PUC's distribution system. During the design to replace the restricted conductor, a wholistic review of the area is completed to determine the most practical solution.

iii. *Historical Investments & Outcomes Observed*: PUC has completed several restricted conductor replacements historically and has observed many positive outcomes from these projects including but not limited to improved safety, maintained or improved system reliability, and improved operational efficiency. When end-of-life poor condition assets are replaced as part of these restricted conductor replacements, this also results in maintained or improved system reliability while also gaining economies of scale.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. INNOVATION

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this investment.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

OH RENEWAL – POLES

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC has a significant amount of overhead (OH) electrical infrastructure. Within that overhead infrastructure, PUC owns approximately 12,600 poles and are currently joint use on another 3,350 Bell Poles. Poles are classed as critical infrastructure due to the role they play in carrying OH assets that deliver safe and reliable electricity to their customers. PUC has an annual pole replacement program. PUC retains a third-party to perform pole testing on 1/7 of its poles annually that are ten years or older to determine poles that require immediate attention, short term attention, and continuous monitoring. The third-party testing results and field identification and inspection by staff are used to inform the asset condition assessment (ACA). This ACA is used to inform PUC's investment plan in unsafe poles. The asset life relative to the typical life cycle is determined on a case-by-case basis. Generally, deteriorated poles are beyond 45 years old, but some poles are identified as deteriorated prior to this due to ground line rot, infestation, woodpecker damage, etc.

PUC undertook an ACA in 2021, which has been used to help build the proposed plan. The full ACA report can be found in Appendix H of the DSP. As of 2021, 4.7% (590) wood poles are in poor condition and 4.6% (574) wood poles are in very poor condition. For the forecast period, PUC plans to replace approximately 60 wood poles per year. As well as replace the poles, PUC will also look to replace associated attachments at the same time. PUC strives to coordinate multiple programs together to optimize replacements. For example, a restricted wire program in the same area as multiple deteriorated poles will allow both programs to be completed at an overall reduced cost.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: 2023 - 2027

iii. Key factors that may affect timing: Projects with higher priority, resource and supply chain constraints.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	499	476	590	312	695	602	611	621	655	611
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	499	476	590	312	695	602	611	621	655	611

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs associated with pole replacements under this program are shown in Section 3 above. The historical information and factors such as inflation, supply chain and material cost factors into replacement costs. As all poles are different, it is difficult to predict a per pole cost on such a small quantity of poles. For the forecasted period, PUC has assumed an average cost of replacing a single pole is approximately $8,000.

6. Investment Priority

Using PUC's prioritization process, this project is ranked 5th out of 11 projects. In the prioritization process, Public Safety is the main contributor to the ranking of the project. Pole replacement projects are based on identification of deteriorated poles and level of risk associated with them in the field. They are one of the most critical pieced of infrastructure as they carry the critical assets that deliver the electricity supply to the customers.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Proactive Pole Replacement** – Dependent on the level of risk for the poles identified, some may be considered emergency replacements, short term replacements (<1year), or long-term replacements (<5years). The proposed proactive replacement of unsafe poles will ensure that the number of unplanned outages remain minimal by avoiding asset failures, so that the customers have access to reliable electricity for their needs. Costs also be reduced when compared with a completing all pole under a reactive program.

- **Option 2: Do Nothing/Reactive Replacement** – PUC does consider reactive replacement for some pole replacements. While this can be employed for unplanned and unexpected failure of poles, it is not sustainable to carry out for all pole replacements. Customers would experience longer and increased unexpected outages. In addition, replacing poles reactively generally incurs a premium as they are unplanned and inevitably are replaced outside normal hours and therefore resource costs increase. This ultimately would increase forced renewal costs.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Although this investment has minimal effect on system efficiency, failure to replace deteriorating poles might result in asset failure and system reliability concerns. This will have an overall negative impact on the efficiency of the distribution system at a given time. In addition, PUC is being efficient in its replacement plan by replacing other associated assets with the poles (conductor, pole-mount transformer, switches) that have also reached or approaching end of life, rather than return at a later date.
Customer Value	Customers located in the area of the identified deteriorated poles will benefit from the system reliability and safety being maintained at current levels, dependent on the nature of the pole. Additionally, proactive pole replacements reduce the cost in comparison to reactive replacements upon failure, reducing PUC's overall costs and minimizing impacts to customer's monthly bills.
Reliability	Reliability performance directly benefits from replacement of deteriorated poles as it reduces the likelihood of unplanned outages which typically result in longer duration outages. Optimal asset conditions are needed to maintain a safe and reliable distribution system. Replacing less than forecast program will cause increased safety and reliability risks as well as increased forced renewal costs.
Safety	Public and employee safety is a driving factor for this investment. Proactively replacing deteriorated poles minimizes the risk of pole failures that can cause potential maintenance and electrical hazards.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Failure risk* - Power supply reliability is the primary driver for this investment. Proactively identifying poles that are close to failure and replacing them minimizes the risk of asset failure. This reduces the risk of prolonged and uncontrolled power outages. Without pole replacements, PUC's reliability statistics would be negatively affected. By replacing the proposed amount of poles PUC will be able to maintain reliability levels.

ii. Secondary Drivers*: Public 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*:* Recent ACA results has identified around 4.7% (590) of poles to be in poor condition and around 4.6% (574) of poles to be in very poor condition. By identifying and proactively replacing poles nearing their end of life and in deteriorated condition, PUC mitigates the risk of outages and provides a safe electrical system by controlling hazards. It is important that customers have access to a safe and reliable distribution system. The full ACA report can be found in Appendix H of the DSP, and additional information on PUC's asset management process is included in Section 5.3 of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: Pole replacements will be constructed using USF standards, PUC standards, and/or specifics approved by a Professional Engineer, which are in line with industry standards.

ii. *Cost-Benefit Analysis*: Each pole replacement is reviewed on a case-by-case basis to identify any available alternatives. Some alternatives may include coordination of replacement programs and/or the replacement of multiple poles with fewer to save costs, additional coordination with adjacent pole owners, etc. However, there are typically no practical alternatives to pole replacements.

iii. *Historical Investments & Outcomes Observed*: Using age distribution of PUC's poles, previous pole testing data, and historical quantities of deteriorated poles identified in the field, PUC attempts to accurately predict the quantity of poles that will require replacement. Costs vary depending on the quantity of the poles identified and the nature of the poles. Historical costs can be found in section 3 and 5 of part A of this document. Through active pole replacement initiatives, PUC has been able to maintain safe and reliable electricity supply.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

STATIONS RENEWAL – SWITCHGEAR, PROTECTION & CONTROL RENEWALS

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC has 14 substations, which house equipment such as switchgear, protection and control assets. These stations are critical in ensuring PUC can supply safe and reliable electricity to its customers. PUC undertakes regular maintenance and testing of its assets on its stations and as such has identified breakers associated to the switchgear that require replacing. As identified through the asset condition assessment, a number of breakers associated with the switchgear have reached end of life and are at greater risk of failure. Historically, PUC has experienced failures of these breakers and have had to borrow un-used tie-breakers from other stations to keep the overall system running. This is no longer a sustainable solution for PUC and is putting greater strain on the network. PUC is proposing to replace two breakers per year for the forecast period with new vacuum style breakers that meet the latest standards and industry accepted technology type. For the test year, 2023, the two replacement breakers will be installed at Substation 1. For the years 2024-2027, two breakers per year will be replaced at other stations which are selected prior to each year. The prioritization of the stations is based on current test results and consideration to the customer exposure that would arise due to a breaker failure (e.g., a feeder with a high customer count, mains vs. tie breaker or feeder).

2. Timing

i. Start Date: 2023

ii. In-Service Date: 2023 - 2027

iii. Key factors that may affect timing: There are currently no known factors that could affect the timing. PUC will continue to monitor supply chain and resource constraints and adjust as required.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	67	37	244	400	1,326	176	178	181	191	178
Contributions	(5)	0	(22)	(39)	0	0	0	0	0	0
Capital (Net)	62	37	222	361	1,326	176	178	181	191	178

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PUC has periodically replaced failed breakers in the past. In 2022, PUC is replacing a failed breaker at Substation 19, with an estimated quote for the breaker of $65K. PUC has used this quote, and included factors such as inflation, install and material costs to forecast its costs for 2023-2027.

6. Investment Priority

This is a high priority investment. If these breakers are not replaced then there is a greater risk of failure. Should a failure occur this could have a significant impact on PUC ability to deliver safe and reliable electricity supply. Using PUC's prioritization process, the project is ranked 6th out of 11. In the prioritization process, Public Safety Impact and Customer Value for Dollars Spent were the primary reasons for the relatively high ranking of this project.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Do Nothing** – This is not an option, as if the breaker fails then PUC ability to supply safe and reliable electricity is severely impacted and in some cases significant outages could be experienced by multiple customers.
- **Option 2: Like for Like Replacement** – This is the preferred option. PUC will replace breakers at risk of failure and at end of life with a new vacuum stye breaker that meets the latest standards.
- **Option 3: Borrow breakers from other stations** – While PUC has employed this tactic occasionally in the past, this is not a sustainable solution. This requires there to be an ability to borrow un-used tie-breakers from other stations. However, this can put strain on the network overall as these stations would no longer have the full protection in place. In addition, the typical type of breaker now used by utilities is a new vacuum style breaker.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This project does not fall in the category requiring leave to construct.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	New breakers installed will meet the latest technology and standards, which inherently makes them more efficient than the older assets. PUC is planning on installing new vacuum style breakers. PUC plans on purchasing the same breakers as they have in the past, which standardizes equipment bringing efficiencies to maintenance and operating tasks.
Customer Value	By upgrading and renewing station assets, PUC will ensure that customer have access to safe and reliable electricity.
Reliability	This investment will upgrade older and poor condition assets that are at risk of failure, with newer assets that which will ensure PUC continue to maintain system reliability.
Safety	By upgrading and renewing older station assets, PUC mitigates hazards from any unexpected failures to increase worker safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Failure Risk* – This investment includes asset renewal projects of assets that are past end of life, in poor and very poor condition and at risk of failure. This will help maintain an efficient and reliable electricity system by reducing the risk of asset failure.

ii. Secondary Drivers: *Functional obsolescence* – PUC strives to maintain an efficient system, so identifying and replacing inefficient or obsolete technology helps PUC achieve operational efficiency.

iii. Information Used to Justify the Investment: This investment is informed by PUC's Asset Condition Assessment and Asset Management Plan, which helps identify end-of-life assets or assets in poor and very poor condition. From the asset condition assessment, 7 switchgear assets were identified as being in poor and very poor condition, with a further 3 in fair condition (in need of consideration for replacement). This data has been used to help inform it asset management plan and the forecast replacements. More details on PUC's asset management plan and asset condition assessment could be found in Section 5.3 and Appendix H of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: The protection and controls meeting interoperability standards will be specified and implemented for this investment. Switchgears used will conform to ESA, CSA, and IEEE standards. PUC is proposing that the new breakers are the new vacuum style breaker which is the latest technology type that utilities use.

ii. *Cost-Benefit Analysis:* Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives. If PUC was to employ the 'Do Nothing' option, it would have to replace any failed breaker reactively, which inherently puts premium on costs compared to pro-active costs. In addition, there are the potential knock on effects of the outages etc.

    Option 3 may seem to be a beneficial option as other breakers are moved from station that's don't require them at the time. However, it is time consuming to keep moving breakers around to the stations that require them. This is a short term solution and is employed in a reactive setting, where there has been an unexpected failure.
    Option 2 allows PUC to be pro-active and plan out its replacement, procuring the breakers through normal timelines rather than in a rush substation (which would typically mean costs are increased. In addition, staff and resources are used during normal operating hours, whereas in a reactive situation, staff could be working out of hours which incurs additional costs.

iii. *Historical Investments & Outcomes Observed:* The historical costs of breakers associated with the switchgear replaced during the historical period are detailed in sections 3 and 5 in part A of this document. PUC has observed that where it has replaced failed breakers it has been able to maintain its ability to deliver safe and reliable electricity supply to its customers.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this investment.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

UG RENEWAL – VAULTS

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. OVERVIEW

PUC's underground distribution system employs concrete chambers for various functions. Manholes provide the junction point on underground ducts to facilitate cable pulling and provide access for inspection of cable splices. Vaults provide below grade space of installation of electrical equipment such as submersible transformers or switches. In the case manholes, steel reinforced concrete is used for walls, roofs and floors. Recent constructure of vaults includes reinforced concrete for the walls and floors (where installed), with steel frames and lids installed. Many historical installations of a vault included less secure walls and relied on the stability of the ground itself. In locations subject to flooding floor drains and sump pumps are provided. Vaults where heat generating equipment such as distribution transformers are installed are also equipped with ventilation grates. Man access is provided through the top. When vaults and manholes are located in roadways, parking lots or other areas open to vehicular traffic, the structures must be designed by a structural engineer. Since manholes and vaults are confined spaces, they must be adequately sized to rescue trapped workers during a fire or explosion inside the vault or manhole. As of June 2022, PUC has approximately 1,440 vaults, including manholes, vaults for pad mounted switches, junction units, minipad transformers and submersible transformers.

The common degradation mode for manholes and vaults is the deterioration of concrete structures due to concrete spalling and corrosion of rebar, sinking of the roof top surfaces allowing rainwater to collect and flood the manhole and vaults. Functional obsolescence, where the size of the manhole or vault no longer meets the space requirements, can also lead to end of life of a structure. The continued reliability and safety of the underground distribution system is reliant on the performance and condition of equipment installed in vaults throughout PUC's service territory.

The health and condition of manholes and vaults can be measured through visual inspection looking for structural damage to concrete walls or roof, frequent flooding incidents, non-functioning drains or sump pumps, or inadequate space. A few examples are shown in the following figures.

Figure 1: Pictures Showing the Condition of Underground Vaults on PUC's System.

The majority of PUC's underground electrical system built in the downtown area is beyond its useful life. Physical inspections within PUC's inspection process identify vaults that require repair and/or rejuvenation. PUC is proposing to address short term vault concerns over the forecast period with the following work:

- **Rejuvenation of major vaults identified as deficient:** PUC is proposing to proactively rejuvenate one major vault per year over the forecast period, for a total of 5 major vault rejuvenations. A major vault in this category generally includes a major pullbox or splice vault and excludes manhole replacements. As vaults are identified through annual inspections, they are added to the list to address. The rejuvenation efforts associated with these major vaults vary from a replacement of steel beams and rebuild of concrete to a complete vault replacement. Structural engineering is required to assess on a vault by vault basis to determine the rejuvenation scope of works.
- **Rejuvenation of minor vaults identified as deficient:** PUC is proposing to proactively rejuvenate 2 minor vaults per year over the forecast period, for a total of 10 minor vault rejuvenations. Minor vaults generally include residential splice vaults, submersible transformer

vaults and pad mounted junction unit vaults. Typically, the rejuvenation efforts associated with these minor vaults include a complete replacement. Many submersible transformer vaults that require replacement are replaced with vaults for minipad transformer installation to improve safety and system reliability.

- **Manhole 123:** Through recent inspections, Manhole 123 has been determined to be a safety hazard to traffic passing over the manhole. The manhole lid has been repaired and secured down to the manhole temporarily to minimize risks. However, there is a reliability concern as significant effort will be required to access the manhole. PUC is proposing to complete a full assessment of Manhole which will include an engineering assessment, and recommendation to rejuvenate the manhole. Upon receipt of the assessment, PUC will determine the best course of action which may include rejuvenation, replacement or reworking the electrical system to eliminate the manhole.

By proactively addressing these structurally deficient vaults and manholes, PUC will be able to prolong the useful life of these structures and protection of the assets within these structures, and also mitigate risks to public safety, employee safety and system reliability while maintaining the long-term viability of the distribution system.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Key factors that may affect timing include material and resource constraints.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	79	68	61	5	0	401	89	91	95	89
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	79	68	61	5	0	401	89	91	95	89

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The costs per vault rejuvenation significantly vary from vault to vault depending on the nature of the repair, especially with major vaults. Replacement of a manhole can be in excess of $250,000 if the deterioration warrants a rebuild. Minor vaults are slightly different and typically result in a $15,000 to $25,000 rebuild.

6. Investment Priority

This is a moderate priority investment, therefore emergency plans and system access projects take precedence over program. Using PUC's prioritization process, this project ranks as 7th out of 11. In the prioritization process, Public Safety is the main contribution to the ranking of this project. Due to the nature of the hazard, it is important to rejuvenate the vaults, removing safety hazards and increasing system reliability.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Do Nothing** – Although it is possible to barricade off the areas around some of the vaults, it is not a practical solution to defer the vault rejuvenation with the increased safety risk to the public.
- **Option 2: Repair Deteriorated Vaults** – Each vault is reviewed on a case by case basis to determine the extent of the deterioration. If a simple repair will safely return the vault to a fair condition extending the vault's useful life, this is completed. In many instances, repair jobs only defer the requirement for rejuvenation and therefore is reviewed in detail prior to proceeding.
- **Option 3: Rejuvenate Deteriorated Vaults** – In cases where the deterioration of the vault has been identified as severe, creating a potential safety hazard, and the deterioration is generally beyond a simple repair, a detailed review from a structural engineer is completed to determine the best solution.

8. Innovative Nature of the Project

There is nothing innovative in this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Planned rejuvenation efforts can be carried out by resources during regular business hours, thus avoiding overtime premiums associated with unplanned efforts potentially occurring after-hours. The proactive rejuvenation of these structures will also ensure continued effective operation of PUC's underground distribution system.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	Customers will benefit via maintained system reliability and reduced risk of vault / manhole failures thereby reducing the potential health and safety risk to customers.
Reliability	The proactive rejuvenation of the structurally deficient vaults and manholes will maintain the reliability performance of the system by reducing the risk of a failure posed by the vaults and manholes.
Safety	By proactively addressing these structurally deficient vaults and manholes, PUC will mitigate risks to public and employee safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Failure Risk* – The identified vaults and manholes requiring rejuvenation have been identified as deficient and are therefore more prone to failure. A failure of a vault or manhole could pose significant safety hazards to workers and the public, while also impacting the reliability and effective operation of the system. This program is required to reduce the failure risk associated with these structures.

ii. Secondary Drivers: *Safety Risk* - This program is needed to rejuvenate those assets such that PUC staff are able to safely enter the vaults to perform work to reduce the outage duration.

iii. Information Used to Justify the Investment: Manholes and vaults are inspected at a minimum frequency of every three years. During these inspections, when a vault demonstrates deterioration to the extent that structural integrity is questioned, the vault is identified as "follow-up required". A more detailed review and inspection from experts occur to determine the most practical course of action. Additional information on PUC's asset management process and maintenance and inspection practices can be found in Sections 5.3.1 and 5.3.3 of the DSP, respectively.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: By proactively addressing deficient vaults and manholes prior to failure, PUC will reduce the cost since work can be performed during regular business hours avoiding overtime premiums that would be incurred if the vaults had to be addressed reactively. In addition, this work will be completed in accordance with PUC's standards and the ON Reg. 22/04 to ensure no undue safety hazard.

ii. *Cost-Benefit Analysis:* Vaults and manholes are an integral part of the underground system, and investments in them are required in order to maintain a safe and reliable system. Doing nothing and running the structures to failure would be more hazardous, costly and impactful relative to proactive rejuvenations as it could impact safety and/or decrease the reliability and operational effectiveness of the system.

iii. *Historical Investments & Outcomes Observed:* PUC has historically not experienced deterioration of many major vaults. Minor vault replacements occur on an annual basis, through inspection, as they are identified as deficient. It is evident that replacement of submersible vaults with vaults to accommodate minipad transformers outside of pedestrian and vehicular traffic areas has reduced safety concerns and maintained system reliability and switching efficiencies.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

STATIONS RENEWAL – BUILDING & FENCE REPAIRS

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Across PUC's fleet of substations, there are many buildings that house the critical infrastructure that is used to operate the station and the system. In addition, each station has fencing around it to restrict access to authorised staff only and to provide safety protection to the general public and to prevent theft and vandalism. PUC has a Station Renewal - Building & Fence Repairs program to ensure the upkeep of the buildings and the associated fences. Projects are typically split into three categories:

- Contingency Repairs – This category addresses any repairs and upgrades to the fencing around the stations, associated grounding and bonding, gates, as well as any unexpected building repairs that are required.
- Station Upkeep and Aesthetics – This addresses items such as rust removal and treatment, painting and general upkeep to ensure the structures and station equipment remain in good condition and to prevent deterioration. Eliminating any potential safety hazards is also a driver.
- Building Structures and associated assets – Any physical building structure upgrades and repairs are covered under this category. For example, replacement or repair of metal clad enclosures or brick buildings.

PUC has designed an annual program, identifying projects across these three categories.

2. Timing

i. Start Date: 2023

ii. In-Service Date: 2023-2027

iii. Key factors that may affect timing: Timing of these upkeep projects is generally not critical other than safety items identified through stations inspections which are addressed promptly when identified. Materials are generally relatively available and have short lead times so no issues with completing this work in a timely fashion is currently anticipated.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	74	1	2	43	86	144	115	97	102	96
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	74	1	2	43	86	144	115	97	102	96

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Due to the nature of the projects within this program, and the fact that they are relatively variable and different, there are no good cost comparators available.

6. Investment Priority

This is a low priority investment, ranked 8th out of 11 material projects in the test year. Other than the handful of grounding repairs and breached station fence repairs anticipated, the balance of other repairs does not constitute an immediate material safety risk. However, if left unaddressed for too long, they are expected to lead to a decrease in service levels through reliability reductions and lead to the need for much more costly remedial solutions in the long term. (e.g., the need to replace an entire switchgear cubicle or overhead structure due to advanced rust rather than sanding and painting minor rusting areas proactively).

7. Alternatives Analysis

Alternatives considered for these projects are case by case as they arise. Generally, in each case, other than the repair approach, 'run to fail' and 'replace with new' are weighed against one another using criteria identified in our prioritizing methodology (i.e., safety impact, outage impact, customer value, system service and project inter-dependability).

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Upgrading assets that to meet the Electrical Safety Authority (ESA) standards assists in maintaining operationally efficient workplace.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	Fences repair is important to maintain public safety, so customers are ensured of a secure and safe electricity facility in their community. In addition, repairs to buildings that house critical operational assets will ensure they are protected from the elements and continue to function as required, ensuring a safe and reliable supply of electricity.
Reliability	This investment does not directly affect the reliability of the electrical system. However, indirectly through these investments the assets are protected from external interference and therefore ensures that PUC can continue to deliver safe and reliable supply.
Safety	Building and fence repairs are required to maintain public and worker safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Safety* – Fences and building repairs help mitigate public and worker safety hazards by maintaining a secure facility.

ii. Secondary Drivers*:* There are no secondary drivers for this investment.

iii. Information Used to Justify the Investment*:* This is a need-based investment that has been budgeted based on historical expenditures. It is essential in securing the substations and ensuring public and worker safety.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: ESA and Ontario Building Code standards followed on exhaust fans and climate control when replacing/ upgrading.

ii. *Cost-Benefit Analysis:* Alternatives considered for these projects are case by case as they arise. Generally in each case, other than the repair approach, 'run to fail' and 'replace with new' are weighed against one another using criteria identified in our prioritizing methodology (i.e., safety impact, outage impact, customer value, system service and project inter-dependability).

iii. *Historical Investments & Outcomes Observed:* Due to the facility being relatively new, PUC has no experience with similar historical costs that can be used for comparison.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

BUILDINGS

INVESTMENT CATEGORY:

GENERAL PLANT

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC has a large operations and administration facility, built in 2012, that represents the critical backbone of PUC's 24/7 operations, as it houses the office and field staff who undertake the daily operations, including customer billing, engineering & planning, field services as well as operations within the control room. Without investing in this facility, there will a be detrimental impact on PUC 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.

As the facility is reaching 10 years in service, PUC has undertaken an extensive review of the facility to identify the most critical projects that are required to be carried out to ensure the safe and reliable continuation of PUC's operations. The following list highlights the proposed work and costs to be carried out in the 2023 Test Year:

Table 1: Proposed Building Work & Costs in 2023

Projects	2023
CO/NOx Detecting System (fleet garage) - Replacement	$100,368
BMS (Building Management System) - Software & Hardware – Replacement	$62,730
Rotary Lift - Fleet Mechanic Shop – Upgrade of Obsolete parts	$18,819
Power Washer - Operations Wash Bay – Replacement of end of life system	$25,092
Misc. Items	$31,365
Total	**$238,374**

2. Timing

i. Start Date: Jan 2023

ii. In-Service Date: Dec 2023-2027

iii. Key factors that may affect timing: If new projects of higher priority in other categories are developed then this may mean PUC will have to adjust its plan for lower priority projects (i.e., System Access (non-discretionary) projects take precedent and resources, and budget may be reassigned).

3. Historical and Forecast Capital Expenditures

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	8	178	110	589	36	238	293	265	361	592
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	8	178	110	589	36	238	293	265	361	592

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Building program investments are ongoing expenditures primarily associated with the upkeep of PUC's main facility located at 500 Second Line in Sault Ste. Marie, which was constructed in 2012. The facility entails the office tower for all administrative staff, operations headquarters, the fleet garage, fueling facilities, stores building and stores yard, and a handful of smaller outbuildings. In the previous 5 historical years, PUC has spent approximately $885,000 maintaining and undertaking minor repair projects to ensure the continued safe, efficient and reliable operations. Of that amount, approximately $700,000 went towards an unplanned project to replace all of the original motor operated roll-up doors in the fleet garage in response to a health and safety near-miss deficiency in which the doors could fall abruptly without notice. The historical costs are identified in section 3 of this document.

Typically each building project is different, and therefore a comparison of historical projects and future projects is not indicative of a particular trend. Over the past year, PUC has begun a formal asset management program specific to facilities which is expected to improve information and planning with respect to this area of general plant moving forward. Currently, PUC engages with contractors and suppliers in developing and understanding associated costs. In addition, factors such as inflation and supply chain and material costs are used to generate the forecast costs.

6. Investment Priority

These investments have been assigned a relatively low priority, ranked as 9th out of the 11 initiatives for the test year. Impacts in the area of safety, customer outages, and customer service levels would be minimal relative to other projects. Any benefits to be derived from this basket of projects are primarily in the area of customer value, where customer dollars are focussed on eliminating inefficiencies that over time would lead to burdensome O&M expenses or costly unplanned capital expenditures to address if deferred for too long.

7. Alternatives Analysis

PUC considered the following options:

- **Option 1: Do Nothing –** This option is not feasible. Many of the assets associated with PUC's facility are reaching their end of life and/or have become obsolete. Without investing in replacing these assets, there is a risk that the facility will not be fit for PUC staff to carry out their jobs safely and efficiently.

- **Option 2: Carry out the proposed pacing of investments –** PUC has identified a list of all minor projects it needs to carry out on its facility. PUC has then determined which are most critical to undertake in the next five years and which can be monitored and pushed out to later years. This has resulted in the proposed project plan that accounts for urgency of investment and the resources and budget available.
- **Option 3: Increase pacing of investments required –** This option would see PUC 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 could take money and resources away from other critical work in the other investment categories. As a result, PUC does not recommend this option.

8. Innovative Nature of the Project

There is nothing innovative about the investments proposed.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	By investing in its facility to keep it up to date, clean and safe, PUC will indirectly ensure that staff can continue to work in a safe and comfortable environment which will enable the staff to maintain its efficiency.
Customer Value	A safe, warm and clean environment ensures that staff can undertake their work effectively and efficiently by delivering what customers need.
Reliability	Through these investments, there is no direct impact on reliability of the network in terms of planned outages. However, the facility houses equipment and materials that are used on a daily basis to help maintain the reliability of the system, and therefore there is an indirect impact. There is also a direct impact of maintaining and upgrading the facilities as in-field crews can continue to get to their work sites and/or respond to outages in a timely manner.

Primary Criteria for Evaluating Investments	Investment Alignment
Safety	The replacement of obsolete and/or end of life assets within the facility, such as the CO/NOx detection system, ensures that PUC has functioning assets that meet the latest health and safety standards and regulations keeping its staff safe while carrying out their work activities.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Non-System Physical Plant* - The primary driver for this program is to renew and invest in PUC's non-system physical plant. Within the context of this program, it is to invest in PUC's facilities that house in-office & operations staff and equipment that is used for maintenance and operations.

ii. Secondary Drivers: *System Maintenance Support* - The facility houses maintenance equipment and vehicles and contains the workshops for the field staff to undertake repairs. By investing in the facility and ensuring it is fit for purpose, PUC is protecting the equipment stored which helps to ensure that they will work when needed.

iii. Information Used to Justify the Investment*:* The following information has been used to determine the proposed projects:

- CO/NOx detection system – The CO/NOx system is an essential life safety system that monitors air quality in the fleet garages and workshops. These are subject to annual inspections. This system has reached its expected end of life (10 years) and to comply with safety rules it requires replacing.
- BMS (Building Management System) - Software & Hardware – This system is the computerized software system that allows facilities to keep an eye on building systems in the main office building including, heating, cooling, ventilation, life safety and access systems. The software will have reached its end of life in 2023 and will no longer be supported by the vendor and will be deemed to be obsolete. Controllers for air handling units, chillers and boilers are no longer compatible with the software and alarms can no longer be cleared due to some hardware failures and software incompatibility. Furthermore, replacement hardware components will also be more difficult or impossible to source as time goes on. As this system is critical to PUC operations, as it keeps buildings running safely and efficiently, it is imperative that it is upgraded to the latest version to ensure it is fully supported by the OEM.
- Rotary Lift – Fleet Mechanic Shop – The electronics and control board for the remote pendant of the Rotary lift no longer function correctly. The original unit has also been identified as obsolete and is no longer supported by the manufacturer. Therefore, an upgrade kit is required to ensure the continued reliable operation of the lift.

- Power Washer - Operations Wash Bay – The power washer is used to keep the PUC fleet clean and maintained in good working order. The unit has been rebuilt several times and it has become cost prohibitive to rebuild further. A replacement unit is now proposed.
- Misc. Items – There is a set of minor projects required which are typically based on the end of useful life of the assets. Currently identified for replacement are controller units for two motor variable frequency drives (VFD) in the building chillers and refractor replacements for heating and hot water system boilers.

3. INVESTMENT JUSTIFICATION

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: To ensure that PUC can deliver safe, reliable and efficient service, it is fundamental that PUC has the necessary foundations in place. For any utility it is accepted practice that an office space is required to house staff from engineering to accounting 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 good practice for utilities to incur costs each year to maintain its back office, field staff shops and storage areas. PUC 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:* On a case-by-case basis for each of the initiatives in this basket of projects, PUC carefully reviews the impacts of doing nothing, completing partial repairs, looking for new solutions or technologies, or employing like for like replacements. This usually entails research of solutions with vendors, reviewing available products online, or consulting with contractors and consultants with expertise in the particular project area. The solution that presents the best long-term value is then selected.

iii. *Historical Investments & Outcomes Observed:* Historical costs are indicated in section 3 of part A of this document. Historical investments have resulted in the ability for PUC staff to continue to perform all its critical services, as well as investing in the upkeep of the building, addressing health and safety defects that were identified. 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:* This is not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing innovative about the investments proposed.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

TOOLS & EQUIPMENT

INVESTMENT CATEGORY:

GENERAL PLANT

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC plan to continue investing in its tools and equipment used to carryout and improve its testing and inspection regimes. This will allow the utility to make informed decisions on replacing and/or repairing key assets. The Tools/Equipment program is designed to equip PUC with tools, monitoring and testing products that will enable the utility to make more informed asset investment decisions such that the utility can continue to provide safe, reliable, and effective services to its customers. The results and data collected from using these tools and equipment will further help enhance PUC's asset condition assessment and help address some of the data gaps identified in the ACA report.

The following tools/equipment will be purchased across the 2023-2025 period. No investments are currently planned for 2026 and 2027. However, PUC will continue to assess this throughout the period and may any adjustments to its budgets as required.

Table 1: Proposed Tools/Equipment for Purchase

Tools/Equipment	Year of replacement	Description of Function
Omicron Injection Tester	2023	This test equipment is essential to allow testing of protection and control systems, ensuring all system relays and breakers operate correctly. This will ensure downed lines and failed equipment do not lead to public or worker safety hazards and that system reliability remains at acceptable levels
Transformer Oil Drying Equipment	2023	This equipment will allow staff to deal promptly, and cost effectively deal with issues of moisture in stations and padmount transformers in-house.
IR Camera	2024	This infrared camera combined with an inspection program is important to identify poor electrical connections and weak spots in the electrical distribution system. With this equipment and program, staff can easily identify and sort simple O&M activities like tightening a connector nut from prominent failures that might require a larger capital investment. An IR scanning program is a cornerstone of a well-managed ACA program.
Transformer Test Equipment	2025	With transformers being one of an LDC's highest investments, investing proactively in test equipment such as this will ensure downtimes are minimized and expenditure is spent prudently. It also will provide enhanced data that could allow PUC to identify a problem before a failure occurs.

Tools/Equipment	Year of replacement	Description of Function
ARCO 400 Recloser Tester	2025	With a number of reclosers currently deployed on the distribution system, and more being added as part of the Sault Smart Grid project currently, this tester will be essential to maintaining reliability and service levels.

2. Timing

i. Start Date: Jan 2023

ii. In-Service Date: 2023-2025

iii. Key factors that may affect timing: The only factor that could affect the timing of the project are supply chain issues. However, PUC does not expect any delays of the delivery of the testing equipment.

3. Historical and Forecast Capital Expenditures

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	0	0	0	0	0	295	68	61	0	0
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	295	68	61	0	0

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PUC periodically purchases or renews various tools and equipment that are used through its testing and inspection programs. In general, PUC purchases its tools through two methods depending upon the application of the tool. For tools that are exclusively for use in the electrical distribution system, PUC buys tools directly, with larger tools being recorded as a one-time capital expenditure. The tools proposed for 2023-2027 in this narrative all fall into that category. For more generic tools that have applications inside and outside of the electrical distribution system, PUC's affiliate company PUC Services Inc. purchases and owns the tools. They are then charged out to the various PUC affiliate companies in proportion to the amount that they are used by each affiliate. For the historical period 2018-2022 there were no tools purchased directly by PUC Distribution Inc. so no historical information is available for comparative purposes.

6. Investment Priority

This is a lower priority investment that was scored 10th out of 11. The equipment proposed to be purchased is critical in PUC being able to carry out their testing programs and gather further data to enable PUC to continue to determine the condition of assets and develop an informed ACA process. This data is then used as an input to help inform the investment plan. Although a deferral of investment now may not have immediate financial or reliability consequences, over time these would be expected to grow.

7. Alternatives Analysis

The following options have been considered:

- **Option 1 – Do Nothing**: Doing nothing is not a viable option for PUC. This would mean that PUC would be unable to carry out the necessary testing and inspections required to help inform the condition of their assets. It would also make it harder for PUC to put together a robust, data driven investment plan. Furthermore, it would put assets at risk of failure and expose customers to longer and more frequent outages in the event of preventable failures.
- **Option 2 – Invest in inspection and testing tools and equipment**: This option sees PUC invest in tools and equipment that allows the field staff to carry out testing and inspections on certain assets, gathering data that is used to inform both capital and maintenance plans. The data can be used to update the asset condition assessment of PUC's assets and inform investment plans. It is common practice amongst utilities to have different testing tools and equipment to help better manage and maintain the electricity network.

8. Innovative Nature of the Project

There is nothing innovative in any of the tools/equipment that PUC is proposing to purchase.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	PUC will be able to integrate the resulting data into their decision-making analytics such as ACA in order to identify and prioritize investment work that is required. In addition, by enhancing their testing methodologies with tools such as an IR camera, this will allow PUC's field technicians to be more targeted in the maintenance they undertake and be able to address issues efficiently and proactively before they materialise, reducing the likelihood of an outage.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	PUC's approach to determining investment is grounded in a data-driven approach. By investing in various tools and equipment, it enables PUC to gather more data on its assets, improve its testing and inspection process. This enables PUC to address the most critical areas on its distribution system.
Reliability	Through continued investment in tools and equipment that allows PUC to carry out its testing and inspection regime, it enables PUC to better assess the condition of its assets. This allows PUC to proactively address the most critical assets, ensuring that the reliability of the system is maintained.
Safety	The results of any inspection and testing help inform which assets need investment, including in need of immediate investment due to safety concerns.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *System Maintenance Support* - The primary driver for this program is to improve its system maintenance support. PUC undertakes regular inspection and testing of its assets. PUC is always looking to make improvements to these processes, both in terms of improving what can be tested and the quality of data. The continued investment in various tools and equipment will enhance PUC's testing capabilities, helping to improve and enhance the development of its investment plans.

ii. Secondary Drivers: There are no secondary drivers for this program.

iii. Information Used to Justify the Investment: Budgeting for these items is based on informal quotes from vendors. Prior to purchase, PUC goes through its formal procurement processes. This involves seeking multiple quotations through an RFP process. These quotes are reviewed prior to purchase of the tools and equipment to ensure that the best value is obtained.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: It is accepted industry practice that utilities should build a data driven investment plan. As part of this, utilities carry out inspections and testing to gather asset condition data. To enable this, various tools and equipment are required, depending on the type of asset. Through investment in the proposed tools and equipment over the forecast period, PUC will be able to improve its knowledge of the condition of its assets which in turn will help refine and inform its investment plans.

ii. *Cost-Benefit Analysis:* On a case by case basis, PUC carefully weighs the pros and cons of purchasing tools to determine the best value approach. For example, test equipment versus contracting out testing services.

iii. *Historical Investments & Outcomes Observed*: Historical costs are indicated in sections 3 and 5 or part A of this document. Through these historical investments in tools and equipment, PUC has been able to successfully gather data that has informed asset condition and been used in its investment decision making process. In addition, these investments have helped PUC's field-staff to better prioritize and carry-out key maintenance activities.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing innovative in any of the tools/equipment that PUC is proposing to purchase.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

OH RENEWAL – GENERAL ASSET

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. OVERVIEW

The general asset renewal tasks included under this program represent small projects over the forecast period that are not considered emergency repairs, do fit within the existing program categories and do not warrant additional program categories. This includes:

- **Removal, cleanup and disposal of pole butts:** As a result of resource constraints and other logistical challenges, it is not always possible to remove poles at the time of the pole replacement. The primary factor for this is the joint use attachments and the legal requirement to permit companies to transfer to the new pole. As a result, there are several poles remaining within PUC's distribution system that need to be addressed. As of July 19, 2021, PUC's database indicates that there are currently 420 outstanding poles to be removed across the service territory, with more anticipated to be identified over the forecast period. On average, PUC has historically pulled 142 poles per year that cannot be removed at the time of replacement. Safe removals require vacuum truck excavations, and the cost of pole disposal has significantly increased recently due to new regulatory requirements, which strictly monitors disposals, especially that of creosote-soaked poles. Over the forecast period, PUC is proposing to remove approximately 150 poles per year that cannot be removed at the time of replacement, clean up an additional 100 poles per year, and dispose of all poles in an environmentally acceptable manner.
- **General Overhead Tasks**: General overhead tasks include minor infrastructure renewal tasks that arise from maintenance programs, field inspections and/or information provided from third parties and can include the replacement of minor assets in poor condition, addressing voltage concerns, and/or planning for future projects.

The bulk of the costs included under this program are associated with the removal, cleanup and disposal of distribution poles.

2. TIMING

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Key factors that may affect timing include resource constraints, response time from communication companies and weather restrictions.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	81	68	74	46	184	172	175	178	188	175
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	81	68	74	46	184	172	175	178	188	175

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Removal of poles after all joint use attachments is the primary cost to this program. Expenditures can fluctuate year to year based on many different factors, including, but not limited to areas of construction, response times of communication companies, resource availability and weather restrictions. The costs to this program are immediately affected by PUC's available resources typically inverse of system access requirements.

6. Investment Priority

This is a low priority investment, therefore emergency plans and system access take precedence over this program. Using PUC's prioritization process, this project ranks 11th out of 11 projects. Although the safety risks of the pole after the wires and related infrastructure have been minimized, completion of the project immediately impacts PUC's image in the community. It is important to complete projects and restore the network to pre-existing conditions.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Complete Communication Transfers –** PUC has reviewed opportunities to complete transfers of joint use attachments at the same time as the pole replacement. After discussions with Joint Use parties, this is not a preferred option as safety and costs would increase.
- **Option 2: Complete Pole Removals After Transfers –** Completing the pole removals after the joint use transfers are completed allows for planned transfers and pole removals increasing safety and optimizing costs.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

.Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The effect on system operation efficiency and cost-effectiveness may vary from project to project; however the nature of the work included within this program will typically have no effect on this in most cases.
Customer Value	Customer value may vary from project to project, however the work included within this program will ensure the elimination of potential safety hazards (e.g., pole butts). Some of the general overhead tasks could also help mitigate potential safety risks and maintain system reliability.
Reliability	The impact on reliability may vary from project to project, however some of the general overhead tasks could also help maintain system reliability.
Safety	The impact on safety may vary from project to project, however the work included within this program will ensure the elimination of potential safety hazards (e.g., pole butts). Some of the general overhead tasks could also help mitigate potential safety risks.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Functional obsolescence* – Once poles are replaced, the pole butts have no functional use and therefore should be removed, cleaned up, and safely disposed of.

ii. Secondary Drivers:

a. *Mandated Obligations* – Due to regulatory requirements, disposals of creosote poles require a licensed contractor to dispose of the material ensuring a safe disposal. Through recent experience and regulatory revisions, the risk of utility assets installed in close proximity (and sometimes through) to PUC poles requires daylighting utility assets within 1m of the pole. This typically requires a vacuum truck to daylight the assets and comply with regulations.

b. *Safety & Reliability* – The work required is due to pole replacements in either system access or system renewal. Many of these replacements help mitigate safety risks and maintain reliability. Please refer to system access and subsequent system renewal programs for further detail.

iii. Information Used to Justify the Investment*:* Information used to justify the investment include PUC's database of outstanding poles that need to be removed, cleaned up and safety disposed of. This information is tracked as part of PUC's asset management process. In addition, information that arises from maintenance programs, field inspections and/or information provided from third parties is also used to identify the need for other general overhead tasks required under this program. Additional information on PUC's asset management process and maintenance and inspection practices can be found in Sections 5.3.1 and 5.3.3 of the DSP, respectively.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: All pole removals, clean ups and disposals will be done in accordance with PUC's standards and practices and will comply with all applicable regulatory requirements.

ii. *Cost-Benefit Analysis*: PUC has assessed the alternative balancing safety, customer impacts and costs. At this time, there are no other practical options to removing the poles after joint use transfers are completed.

iii. *Historical Investments & Outcomes Observed*: The historical costs of pole removals, clean ups and disposals during the historical period are detailed in sections 3 and 5 in part A of this document. Through its program, PUC has been able to successfully implement this work and reduce the backlog of outstanding pole butts scattered across its service territory.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

Appendix B

East Lake Superior Region Needs Assessment Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

East Lake Superior Region

Date: June 14th, 2019

Prepared by: East Lake Superior Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the East Lake Superior 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	East Lake Superior Region		
LEAD	Hydro One Sault Ste. Marie LP.		
START DATE	April 16th, 2019	**END DATE**	Jun 14th , 2019

1. INTRODUCTION

The first cycle of the Regional Planning process for the East Lake Superior (“ELS”) Region was initiated by the former Great Lakes Power Transmission (“GLPT”) in October 2014 and completed in December 2014 with the publication of the Needs Assessment (“NA”) Report. The NA Report 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 Report is to review the status 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 for each region. The first cycle of Regional Planning for the ELS Region was triggered in October 2014, and this second cycle Regional Planning was triggered in April 2019.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous Regional Planning process; and
- Identification and assessment of 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 SA, IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from LDCs, the IESO, Hydro One Sault Ste. Marie and Hydro One provided input and relevant information for the East Lake Superior 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 electrical infrastructure needs and to determine whether further regional coordination or broader studies would be beneficial for addressing these needs.

The scope of the assessment includes reviewing previously identified needs and identifying new needs based on available information including load forecasts, conservation and demand management (“CDM”), distributed generation (“DG”) forecasts, reliability concerns, operational issues, and major high voltage equipment identified to be at or near the end of their useful life.

A technical assessment of needs was undertaken based on:

- Planning criteria outlined in IESO-ORTAC (section 2.7.2) for analysis of current and future station capacity and transmission adequacy;
- Planning criteria outlined in IESO-ORTAC (section 7) for system reliability; Analysis of major high voltage equipment reaching the end of its useful life, in conjunction with emerging system needs; and
- Analysis of operational concerns relevant to Regional Planning

6. NEEDS

I. Station & Transmission Supply Capacity

- Based on planning criteria, Third Line TS 230/115kV Autotransformers T1 and T2 are expected to approach their 10-Day Limited Time Rating over the near/mid-term planning horizon.

II. System Reliability & Operation

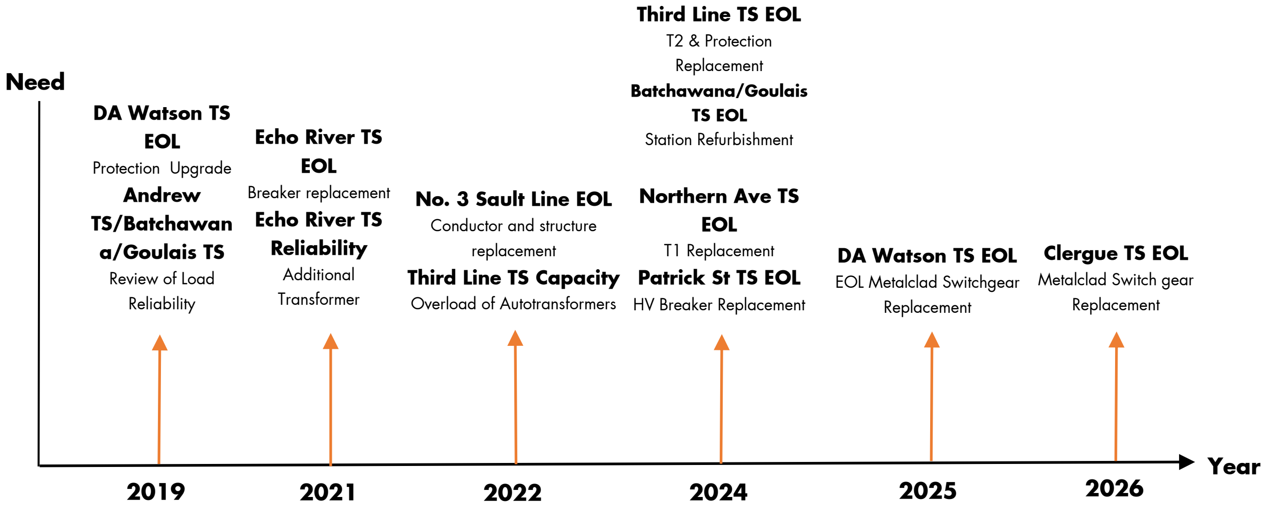
- Based on forecasted winter gross load, load security criteria can be met over the study period.
- Load restoration at transformer stations listed below requires further review with affected LDC:
  - i. Andrew TS
  - ii. Batchawana TS
  - iii. Goulais TS

III. Aging Infrastructure – Transformer Replacements and Circuit Refurbishments

- Projects in execution:
  - i. DA Watson TS – Protection Upgrade

- Future projects:
  - i. Echo River TS – EOL Breaker Replacement
  - ii. No.3 Sault Circuit – EOL Conductor and Structure Replacement
  - iii. Third Line TS – Transformer T2 EOL and Protection Replacement
  - iv. Patrick St TS – HV Breaker Replacement
  - v. Batchawana TS / Goulais Bay TS – Station Refurbishment
  - vi. Northern Ave TS – Transformer T1 Replacement
  - vii. DA Watson TS – Metalclad Switchgear Replacement
  - viii. Clergue TS – Switchgear Replacement

Needs Timeline Summary



7. RECOMMENDATIONS

The Study Team's recommendations for the above identified needs are as follows:

1. Overloading of 230/115 kV Autotransformers at Third Line TS – Further analysis in the Scoping Assessment phase of Regional Planning is required to address supply capacity to the 115 kV systems. IESO will lead the Scoping Assessment phase to determine and to recommend the best planning approach to address the need.

2. Reliability to Load - Load restoration after loss of a single element may lead to longer restoration time than ORTAC guidelines. A review by the transmitter and impacted distributor is required to evaluate the local reliability for the following stations:

   i. Andrew TS
   ii. Batchawana TS
   iii. Goulais TS

3. The implementation and execution for the replacement of the following EOL transmission assets will be coordinated between Hydro One Sault Ste. Marie and the affected LDCs and/or customers, where required. These projects will be coordinated with IESO where required and where feasible within the timelines afforded by each project.

   i. Echo River TS – Breaker Replacement
   ii. No. 3 Sault Conductor and Structure Replacement
   iii. Third Line TS – Autotransformer T2 & Protection Replacement
   iv. Patrick St TS – HV Breaker Replacement
   v. Batchawana TS / Goulais Bay TS – Station Refurbishment
   vi. DA Watson TS – Metalclad Switchgear Replacement

vii. Clergue TS – Switchgear Replacement

4. Overload of No. 1 Algoma circuit due to breaker failure at Patrick St TS and/or other multiple element contingencies requires additional study. Further analysis in the Scoping Assessment phase of Regional Planning is required to determine the best planning approach while taking into account the outcome of an ongoing SIA for new load connection at Patrick St TS.

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

This Needs Assessment ("NA") report identifies needs in the East Lake Superior ("ELS") Region. For needs that require coordinated regional planning, the Independent Electricity System Operator ("IESO") will initiate the Scoping Assessment process to determine the appropriate regional planning approach. The approach can either be the IESO-led Integrated Regional Resource Planning ("IRRP") process or the transmitter-led Regional Infrastructure Plan ("RIP"), which focuses on the development of "wires" solutions. It may also be determined that the needs can be addressed more directly through localized planning between the transmitter and the specific distributor(s) or transmission connected customer(s). The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's ("OEB") Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements.

The purpose of the second cycle NA is to review the status 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 ELS Region Needs Assessment Study Team listed in Table 1, and led by the lead transmitter in the region, Hydro One Sault Ste. Marie ("HOSSM"). The report captures the results of the assessment based on information provided by the LDCs, Hydro One Network Inc. and the IESO.

Table 1: East Lake Superior Region Study Team Participants

Company
Hydro One Sault Ste. Marie LP. (Lead Transmitter)
Hydro One Networks Inc.
Algoma Power Inc.
Chapleau PUC
Hydro One Distribution
Independent Electricity System Operator ("IESO")
Sault Ste. Marie PUC

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. The first cycle of Regional Planning for ELS Region was triggered in October 2014, and as such, the second cycle Regional Planning was triggered in April 2019.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the entire ELS Region and includes:

- Review of existing needs and/or plans identified in the previous planning 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"), Local Planning ("LP"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The ELS Region includes all of Hydro One Sault Ste. Marie's (formerly Great Lakes Power Transmission's) 560 km of HV transmission lines as well as ties to the provincial grid at Wawa TS in the Northwest and Mississagi TS in the Northeast. Hydro One Network's 115 kV W2C circuit also supplies the Town of Chapleau from Wawa TS. The boundary of the ELS Region is shown in Figure 1. Figures 2-5 show Single Line Diagram ("SLD") depictions of various parts of the ELS Region.

Figure 1: Geographic Area of the East Lake Superior (ELS) Region

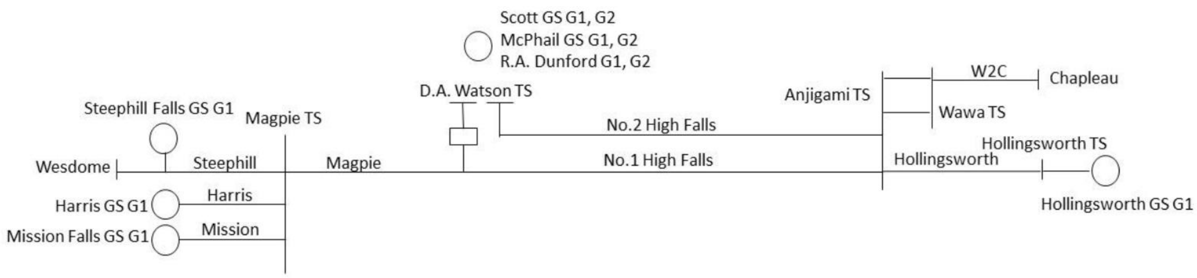


Figure 2: ELS Region – Northern Area Single Line Diagram

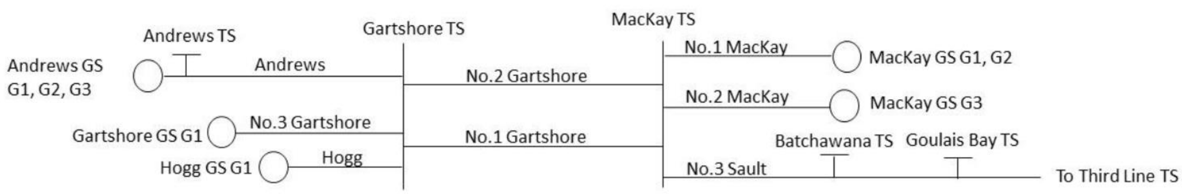


Figure 3: ELS Region – Southern Central Area Single Line Diagram

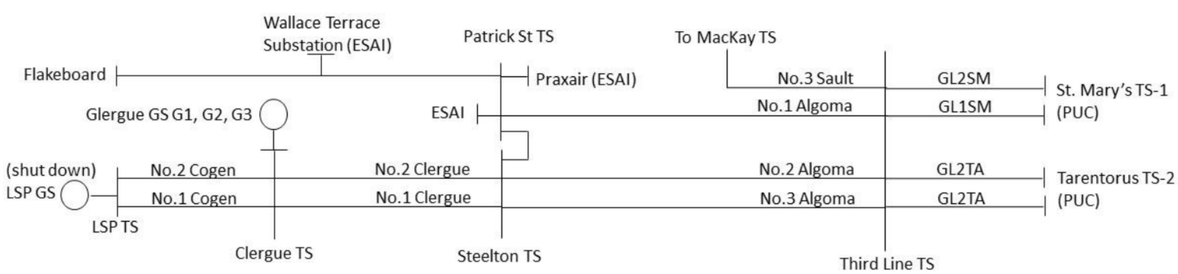


Figure 4: ELS Region – Southern Area Single Line Diagram

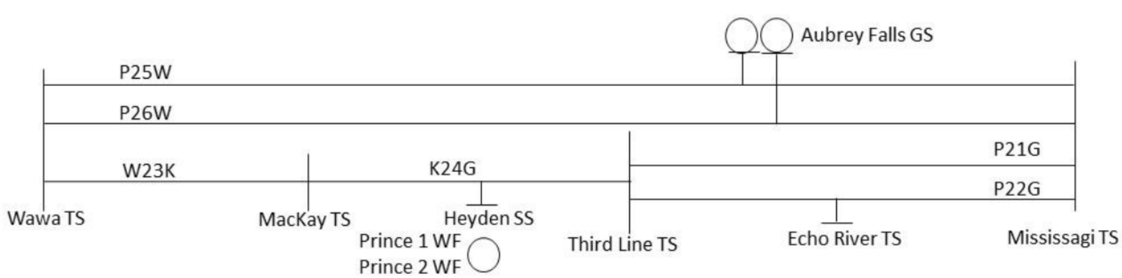


Figure 5: ELS Region – Eastern Area Single Line Diagram

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, Hydro One and HOSSM provided information and input for producing the ELS Region NA Report. The information provided includes the following:

- ELS Region Summer and Winter Non-Coincident Load Forecast for all supply stations
- ELS Region Summer and Winter Coincident Load Forecast for all supply stations
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are in scope for the ELS Region.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

- Load forecast: The relevant LDCs provided load forecasts for their respective load supply stations in the ELS Region for the ten (10) year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the ELS region. The region's extreme summer and winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast load growth rates to the actual 2018 summer and 2017/2018 winter peak extreme weather corrected loads, with Hydro One providing extreme weather correction factors. The net extreme weather summer and winter load forecasts were then produced by subtracting the percentage CDM reduction, and the amount of effective DG capacity from each station's gross load forecast. These extreme weather summer and winter load forecasts for the individual stations in the East Lake Superior region are given in Appendix A;
- Relevant information regarding system reliability and operational issues in the region; and
- List of major high voltage transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life which is relevant for regional planning purposes. This includes transformers, autotransformers, Breakers, and overhead 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.

In addition, the following assumptions were made in this Needs Assessment:

- The new East-West Tie Transmission Reinforcement is included in the assessment model.

- The region is winter peaking, but the study includes both winter and summer peak loads with interface transfer at normal limits to investigate effects of equipment limit changes relative to different seasonal peaks.

- Adequacy of transformation capacity at load stations was assessed assuming a 0.9 lagging power factor and non-coincident station loads.

- Adequacy of the following transmission lines capacity was assessed assuming a 0.9 lagging power factor and non-coincident station peak load due to the radial nature of the connections:

    - 115kV GL1SM (Third Line TS x St. Mary's MTS)
    - 115kV GL2SM (Third Line TS x St. Mary's MTS)
    - 115kV GL1TA (Third Line TS x Tarentorus MTS)
    - 115kV GL2TA (Third Line TS x Tarentorus MTS)

- Adequacy of transformation capacity for 230/115kV autotransformers T1 and T2 at Third Line TS, as well as transmission lines adequacy (excluding the above) were assessed using coincident system peak load in different seasons. Furthermore, this assessment investigated network capacity based on two (2) different configurations of the No.3 Sault circuit:

    - No.3 Sault circuit is connected radially to MacKay CGS G3 until 2022 with limited capacity;
    - No.3 Sault circuit is not radially connected to MacKay CGS G3 from 2022 onwards to 2028, with current capacity restrictions removed (restore to original capacity).

  Subsequently, four (4) major scenarios were investigated per season:

East – West Tie (Flow West)		East – West Tie (Flow East)	
No.3 Sault Radial	No.3 Sault Not Radial	No.3 Sault Radial	No.3 Sault Not Radial

- For the Sault Ste. Marie area, hydro generation is assumed to be at 98% dependable when all elements are in service, as well as during N-1 contingency analysis as per IESO-ORTAC. Hydro generation stations with water storage capacity (ie: Aubery Falls GS and Wells GS) typically generates at peak. Half of its respective generation capacity (equivalent to 1 unit) is assumed available when assessing autotransformer and transmission line adequacies.

- One of the industrial customers in the Sault Ste. Marie area has acquired Lake Superior Power ("LSP") Generating Station. There is currently a project to re-route two (2) of LSP's generators as embedded generation, with the remaining generator to be re-connected to Clergue TS via 115kV No. 1 and No. 2 CoGen circuits. In developing the worst case base case scenario, the study assumed generation from LSP to be unavailable.

7 NEEDS

This section assess the adequacy of regional infrastructure to met the forecasted load in the East Lake Superior Region and identify needs. The section also reviews and/or reaffirms needs previously identified in the last cycle of regional planning.

7.1 Review of Needs Identified in the Previous Cycle of Regional Planning

This section review the status of the needs identified in the previous cycle of Region Planning as summarized in Table 2 below.

Table 2: Needs Identified in the First Cycle Regional Planning Cycle

Type of Needs identified in the first RP cycle	Needs Details	Current Status
Transmission Supply Capacity of Hollingsworth TS / Anjigami TS Transformers	Overloading at Anjigami T1/ Hollingsworth T2	Pending confirmation for new customer connection
Transmission Supply Capacity of No. 1 Algoma Circuit	Thermal overloading on No. 1 Algoma circuit upon Breaker 214 Fail Contingency, where No. 2 and No. 3 Algoma lines will be removed from service	Continue to work with impacted customers to arrive at mutually agreeable solution.
Transmission Supply Reliability	Echo River TS – Single Transformer Supply	Transmitter and affected LDC have developed project scope for the installation of an additional transformer

a. Transmission Supply Capacity of Hollingsworth TS and Anjigami TS

Based on the previous NA, Hollingsworth TS – Transformer T2 / Anjigami TS – Transformer T1 will become overloaded due to a large customer connecting to the 44kV system. The customer has since put the connection application on hold. This need will be studied within the load connection process when the customer decides to proceed.

b. Transmission Supply Capacity of No. 1 Algoma Circuit

Based on the previous NA, No.1 Algoma Circuit may become overloaded after a breaker fail contingency at Patrick St. TS that removes No.2 Algoma and No.3 Algoma circuits by configuration. This overload is observed depending on the amount of load supplied from Patrick St. TS. This overload continues to be observed; refer to section 7.3 of this report for details.

c. Transmission Supply Reliability

Based on the previous NA, load restoration criteria cannot always be met at Echo River TS upon a transformer failure. HOSSM has been working with the impacted LDC, where HOSSM has developed and discussed different options that varies in levels of reliability and cost. HOSSM and the impacted LDS have come to an agreement to install a second transformer to improve reliability to load. The decision is reflected in HOSSM's and LDC's recent rate application.

7.2 Assessment of Transmission Capacity Needs in the Region

230kV Connection Facilities

Based on the demand forecast, there is sufficient step-down transformation capacity throughout the study period at Echo River TS.

Voltage performance for the 230kV system is within the ORTAC guidelines upon observing N-1 contingencies, and after taking control actions such as switching in and out shunt capacitor banks at Wawa TS or Third Line TS.

230/115kV Auto-transformation Facilities

Third Line TS
No capacity concerns when both Third Line autotransformers are in-service.

Upon N-1 contingency, autotransformers at Third Line TS will approach their 10-Day Limited Time Ratings (LTRs) by Winter 2022. The loading on the companion bank, subjected to different circuit configurations, is as follows:

No.3 Sault 3 Radial		No.3 Sault 3 Not Radial	
All elements in service	**N-1 (Third Line TS Autotransformer Contingency)**	**All elements in service**	**N-1 (Third Line TS Autotransformer Contingency)**
Third Line Autotransformer within its Continuous Rating	290.45MVA (100% of 10 day LTR)	Third Line Autotransformer within its Continuous Rating	273.57MVA (94.3% of 10-Day LTR)

The overload of Third Line TS auto-transformers is a capacity need.

MacKay TS
Prior to year 2022, no overloading on 115 kV circuit No.3 Sault is observed for loss of MacKay Transformer T2 due to No.3 Sault's radial configuration. Post year 2022, after No. 3 Sault line is no longer radially connected to Mackay G3, overloading of No. 3 Sault upon loss of T2 or upon loss of 230 kV circuit K24G will be mitigated by arming the existing MacKay TS Generation Rejection (G/R) Scheme.

115kV Connection Facilities

Based on the demand forecast, there is sufficient transformation and circuit capacity throughout the study period for 115kV connected load stations.

Voltage performance for the 115kV system is within the ORTAC guidelines upon N-1 contingencies

Load Security

As per IESO ORTAC criteria:

Criteria 1: With all transmission facilities in-service and coincident with an outage of the largest local generation unit, equipment within continuous rating, voltages must be within normal ranges, and transfers must be within applicable normal condition.

Assessment

- in the 230 kV system the largest unit is a Wells GS G1 or G2 unit;
- in the 115 kV system the largest unit is Clergue GS G2;

Under both outage scenarios, all equipment are within their continuous ratings, voltages are within normal ranges, and transfers are within applicable normal conditions. Hence it is concluded that Criteria 1 is satisfied.

Criteria 2: With any one element out of service, all equipment and circuits within applicable limits and load curtailment/Load Rejection only for local generation outages. No more than 150MW of load may be interrupted by configurations and by planned load curtailment or load rejections.

Assessment

- No more than 150MW is loss by configuration or load rejection. Therefore Criteria 2 is satisfied.

Criteria 3: With any two elements out of service, all equipment and circuits within applicable limits by time afforded by short-term ratings. Planned load curtailment or L/R exceeding 150 MW permissible for only local generation outages, and not more than 600 MW of load interrupted by configuration, by planned load curtailment or Load Rejection.

Assessment

- The projected regional gross load at coincident peak is forecasted at 377MW in 2028.
- Approximately 70MW of load will be rejected for a breaker fail contingency at Patrick St TS. If breaker 214 fails to open, both No.2 and No.3 Algoma circuits will be loss by configuration. This results in overload of No.1 Algoma circuit. This load rejection is required to decrease area loading in order to respect No. 1 Algoma circuit's long-term emergency rating of 128MVA. The impact is currently being assessed in a pending System Impact Assessment (SIA) from the IESO.
- Loss of 230kV P21G and P22G due a common tower contingency, or loss of both T1 and T2 Autotransformer at Third Line TS, will trigger instantaneous load rejections schemes at Third Line TS. At 98% dependable hydro generation, approximately 103MW of planned load curtailment or load rejection is required to bring the system to within applicable rating. It is expected that continued reliance on this load rejection scheme is necessary.
- Therefore, no more than 600MW of load will be interrupted by configuration, and no more than 150MW will be rejected by planned load curtailment or L/R scheme. It is concluded that Criteria 3 is satisfied.

Load Restoration

The ELS region has multiple radial single circuit and/or single transformer load connection stations where load loss is anticipated after a single transformer and/or single circuit contingency. At these locations ORTAC restoration criteria of 8 hours may not always be met. Stations that are impacted include:

- Andrew TS
- Batchawana TS
- Goulais TS

There is a need to review load restoration reliability at these stations.

The loss of 230kV P21G and P22G due a common tower contingency, or loss of both T1 and T2 Autotransformer at Third line TS, will trigger instantaneous load rejections schemes at Third Line TS. Loss of P21G and P22G will only take T1 out by configuration. Load restoration after operation of planned load curtailment / L/R scheme can proceed gradually via remaining 230kV connection (K24G and T2). Load restoration upon loss of both T1 and T2 will proceed gradually on HOSSM 115kV system via No.3 Sault circuit and Clergue GS. Therefore, ORTAC load restoration requirements are met.

7.3 Sensitivity Analysis

This Needs Assessment is subject to local area contingency criteria. To bridge the gap between regional and bulk system planning, the following bulk power system contingencies were assessed:

- Loss of No.2 and No.3 Algoma Lines due to Breaker 214 failure

Observations are as follows:

Based on the load forecast, a breaker failure contingency of circuit breaker 214 at Patrick St TS will remove No. 2 and No. 3 Algoma lines simultaneously by configuration, causing an overload on No. 1 Algoma circuit. The impact is also being investigated in a pending IESO's System Impact Assessment (SIA).

7.4 Assessment of End-Of-Life (EOL) Equipment Needs in the Region

HOSSM and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next ten (10) years:

- Autotransformers
- Power Transformers

- HV and LV Breakers
- Transmission Circuits
- Protection System

Accordingly, following major high voltage equipment has been identified as approaching its EOL over the next 10 years.

Table 3: End-of-Life Equipment – East Lake Superior Region

EOL Asset Replacement/ Refurbishment	Replacement / Refurbishment Timing	Notes
Projects in Execution		
DA Watson TS – Protection Upgrade	End of 2019	This project is discussed further in Section 7.4.1
Future Projects		
Echo River TS – Breaker Replacement	2021	These Project are discussed further in Section 7.4.2
No.3 Sault Conductor and Structure Replacement	2022	
Third Line TS – Autotransformer T2 & Protection Replacement	2024	
Patrick St TS – HV Breaker Replacement	2024	
Batchawana TS / Goulais Bay TS – Station Refurbishment	2024	
Northern Ave TS – Transformer T1 Replacement	2024	
DA Watson TS – Metalclad Switchgear Replacement	2025	
Clergue TS – Switchgear Replacement	2026	

The EOL assessment for the above high voltage equipment included consideration of the following options:

1. Maintaining the status quo;
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 by transferring portions of load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;
5. Replacing equipment with similar equipment and built to current standards (i.e. "like-for-like" replacement);
6. Replacing equipment with higher ratings (right-sizing) due to forecasted increase in demand or due to load transfer and built to current standards; and
7. Station reconfiguration

From HOSSM's perspective as a facility owner and operator of its transmission equipment, status quo is generally not an option for major high voltage equipment due to safety and reliability risk of equipment failure.

7.4.1 Projects in Execution

The following EOL refurbishment project is currently under execution. Since the completion of the last RP, the need for proceeding with this project arose before the initiation of the second RP cycle. Hence, the following project was not listed or discussed during the first cycle of regional planning and are currently in execution:

DA Watson TS – Protection Upgrade

DA Watson TS is an 115kV station that connects multiple local hydraulic generating stations to HOSSM transmission system. Protection relays at DA Watson TS are at increased risk of failure and have been deemed obsolete by their manufacturer with limited spares parts and technical support available. In addition, the high arc flash hazard rating of the existing DA Watson TS metalclad switchgear compromises equipment integrity, system stability and worker safety.

The scope of work includes installing modern protection relays with arc flash detection mounted in racks located away from the metalclad switchgear. These new relays will also directly communicate with Hydro One's Network Management System (NMS) utilizing the OC3 SCADA network.

7.4.2 New Needs

The following EOL refurbishment needs have been identified in the current regional planning cycle:

1. **Echo River TS – Breaker Replacement**

Echo River TS is a 230kV load supply station. The station consists of a single step-down transformer and a single 230kV circuit breaker to supply two (2) 34.5 kV customer feeders. Based on results of an asset condition assessment, the 230 kV circuit breaker is currently in deteriorating condition. This breaker is a live tank minimum oil breaker, which is considered obsolete and is due for replacement.

In consultation with the affected LDC, the breaker replacement will be coordinated with the other need at Echo River TS. The planned in-service year is 2021.

2. No.3 Sault Conductor and Structure Replacement

No.3 Sault is a 115kV transmission circuit that runs from MacKay TS 115kV station yard to Third Line TS 115kV station yard. This circuit provides an alternative path for local generation to reach load centres close to the Sault Ste. Marie area. Based on an asset condition assessment, No.3 Sault circuit is currently rated between "Poor" and "Very Poor" as it has multiple component (sleeves) failures and aging conductors. This circuit also accounts for 39% of all line equipment related outages experienced over the 2013 – 2017 period. The circuit is currently de-rated as a pre-cautionary action to minimize further stress.

The EOL replacement work of approximately 70km of conductor from Batchawana TS to MacKay TS includes replacing selected wood poles along the corridor as condition warrants. The planned in-service date is 2022. Based on load forecast, similar conductor ratings are expected. Due to the urgency the replacement, line rating will be reviewed within timeline afforded by the project.

3. Third Line TS – Autotransformer T2 & Protection Replacement

Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Third line TS 115kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, No.3 Sault circuit and Northern Ave circuit. It also supplied two (2) LDC HV load supply stations via 115kV circuits GL1SM GL2SM, GL1TA, and GL2TA. Based on an asset condition assessment, autotransformer T2 is approaching its EOL.

Based on the load forecast, similar ratings are required for the EOL autotransformer T2 replacement. While it is recognized that there is a capacity related need at the station as per Section 7.2 (to be considered in the Scoping Assessment Phase), the replacement of T2 will not alleviate the capacity need, as the replacement transformer (with similar ratings) is the largest standard size autotransformer available. To maintain supply reliability in the ELS Region, the planned in-service date for replacing T2 autotransformer and associated EOL protections is year 2024.

4. Patrick St TS – HV Breaker Replacement

Patrick St TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2 and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No .1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area.Based on an asset condition assessment, four (4) out of thirteen (13) 115kV breakers are minimum oil live tank breakers and they are considered obsolete.

Based on the load forecast and expected system conditions, similar equipment ratings are required for EOL replacement. The current plan is to replace these four (4) obsolete breakers with new SF6 breakers, complete with new breaker disconnect switches. The planned in-service date for this project is 2024.

5. Batchawana TS / Goulais Bay TS – Station Refurbishment

Batchawana TS and Goulais Bay TS are load supply stations that are in proximity of each other, and both are connected to 115kV No.3 Sault circuit. Each station is currently configured with a single transformer supply. Based on an asset condition assessment, both stations are in a deteriorated state with obsolete equipment including power transformers, protections (fuse), batteries, chargers, and remote terminal units.

The scope of refurbishment is still under development, with different options under evaluation. HOSSM is actively engaging the local LDC to arrive at a mutually agreeable solution. The planned completion date for this refurbishment is anticipated to be 2024.

6. Northern Ave TS – Transformer T1 Replacement

Northern Ave TS is a 115kV load supply station that is connected to Third Line TS via 115kV Northern Ave circuit. Northern Ave Transformer T1 is a 115/34.5kV, 20/26.7MVA step down transformer that supplies Algoma Power Inc. via one (1) 34.5kV feeder. Transformer T1 has been in-service since the 1970's, and it is now approaching its EOL.

Based on the load forecast, similar equipment ratings are required for EOL replacement. The current plan of replacing T1 and associated equipment has an in-service date of year 2024.

7. DA Watson TS – Metalclad Switchgear Replacement

DA Watson TS is a 115kV load supply station that also has connectivity with three (3) local hydro generating stations. The station has two 45/60/75 MVA transformers and nine 34.5kV feeders. Based on an asset condition assessment, the existing metalclad feeder breakers are obsolete and near EOL.

Based on the load forecast and expected system conditions, similar ratings are required for EOL feeder breaker replacements. The planned in-service date to replace existing metalclad breakers and associated equipment at DA Watson TS is year 2025.

8. Clergue TS – Switchgear Replacement

Clergue TS is a 115kV station that connects Clergue Generating Station and LSP co-generation station to the HOSSM system via two (2) 115kV circuits emanating from Patrick St TS. Based on an asset condition assessment, the existing 12 kV minimum-oil metal-clad switchgear is obsolete and approaching EOL.

Based on the load forecast and expected system conditions, similar equipment ratings are required for EOL replacement. The planned in-service date to replace the metalclad switchgear and associated equipment is year 2026.

8 CONCLUSION AND RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends the following:

1. The overload of the 230/115 kV auto-transformers at Third Line TS requires further regional coordination in the Scoping Assessment phase of Regional Planning to determine the best study approach to address the need. IESO will lead the Scoping Assessment phase.

2. Reliability to load at Andrew TS, Batchawana TS and Goulais TS to be reviewed. The review to be conducted by the transmitter and impacted distributor to evaluate the local reliability needs on a case by case basis.

3. The implementation and execution for the replacement of the following EOL transmission assets will be coordinated between Hydro One Sault Ste. Marie and the affected LDCs and/or customers, where required. These projects will be coordinated with IESO where required and where feasible within the timelines afforded by each project.

   ii. Echo River TS – Breaker Replacement
   iii. No.3 Sault Conductor and Structure Replacement
   iv. Third Line TS – Autotransformer T2 & Protection Replacement
   v. Patrick St TS – HV Breaker Replacement
   vi. Batchawana TS / Goulais Bay TS – Station Refurbishment
   vii. Northern Ave TS – Transformer T1 Replacement
   viii. DA Watson TS – Metalclad Switchgear Replacement
   ix. Clergue TS – Switchgear Replacement

4. The overload of Algoma No. 1 Circuit due to breaker failure at Patrick St TS and/or other multiple elements contingencies required additional study. Further analysis in the Scoping Assessment phase of Regional Planning is required to determine the best planning approach while taking into account the outcome of an ongoing SIA for new load connection at Patrick St TS.

9 REFERENCES

[1] East Lake Superior Region Need Assessment Report – December 2014
https://www.hydroone.com/about/corporate-information/regional-plans/east-lake-superior

[2] 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

[3] Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 – August 2007
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Appendix A: East Lake Superior Region Winter & Summer Non-Coincident Load Forecast

Winter Non-Coincident Load Forecast [MW]

Transformer Station		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
St. Mary's MTS (T1/T2)	Gross	52.16	51.78	51.39	51.01	50.63	50.25	49.88	49.51	49.14	48.78	48.41
	CDM	19.49	19.49	19.49	19.49	19.49	19.49	19.49	19.49	19.49	19.49	19.49
	DG	0.61	1.10	1.11	1.12	1.18	1.21	1.25	1.30	1.35	1.37	1.30
	Net	33.60	32.68	32.27	31.85	31.40	30.97	30.54	30.10	29.66	29.26	28.95
St. Mary's MTS (T3/T4)	Gross	51.97	51.58	51.20	50.82	50.44	50.06	49.69	49.32	48.96	48.59	48.23
	CDM	19.57	19.57	19.57	19.57	19.57	19.57	19.57	19.57	19.57	19.57	19.57
	DG	0.61	1.10	1.10	1.12	1.17	1.20	1.25	1.29	1.35	1.36	1.29
	Net	31.79	30.92	30.53	30.13	29.70	29.29	28.88	28.47	28.04	27.66	27.37
Tarentorus MTS (T1/T2)	Gross	64.35	63.87	63.40	62.93	62.46	61.99	61.53	61.08	60.62	60.17	59.72
	CDM	19.56	19.56	19.56	19.56	19.56	19.56	19.56	19.56	19.56	19.56	19.56
	DG	0.76	1.36	1.37	1.39	1.45	1.49	1.55	1.60	1.67	1.69	1.60
	Net	43.08	42.03	41.55	41.07	40.55	40.06	39.55	39.06	38.54	38.08	37.73
Tarentorus MTS (T3/T4)	Gross	69.04	68.52	68.02	67.51	67.01	66.51	66.01	65.52	65.04	64.55	64.07
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.81	1.46	1.47	1.49	1.56	1.60	1.66	1.71	1.79	1.81	1.72
	Net	68.23	67.07	66.55	66.02	65.45	64.91	64.36	63.81	63.25	62.74	62.35
Andrews TS (T4)	Gross	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Net	0.22	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Batchawana TS	Gross	1.50	2.01	2.02	2.03	2.04	2.05	2.06	2.07	2.08	2.09	2.10
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.02	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.06
	Net	1.48	1.96	1.97	1.98	1.99	2.00	2.01	2.01	2.02	2.03	2.04
DA Watson CTS (T1/T2)	Gross	7.85	7.93	8.01	8.09	8.17	8.25	8.33	8.41	8.50	8.58	8.67
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.09	0.17	0.17	0.18	0.19	0.20	0.21	0.22	0.23	0.24	0.23
	Net	7.76	7.76	7.84	7.91	7.98	8.05	8.12	8.19	8.27	8.34	8.44
Echo River TS (T1)	Gross	12.61	12.74	12.87	13.00	13.13	13.26	13.39	13.52	13.66	13.80	13.93
	CDM	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	DG	0.15	0.27	0.28	0.29	0.31	0.32	0.34	0.35	0.38	0.39	0.37
	Net	12.36	12.37	12.49	12.61	12.72	12.84	12.95	13.07	13.18	13.31	13.46
Goulais Bay TS (T1)	Gross	9.01	9.10	9.19	9.28	9.38	9.47	9.56	9.66	9.76	9.85	9.95
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.11	0.19	0.20	0.20	0.22	0.23	0.24	0.25	0.27	0.28	0.27
	Net	8.90	8.91	8.99	9.08	9.16	9.24	9.32	9.41	9.49	9.57	9.68
Hollingsworth TS (T2) Anjigami TS (T1)	Gross	12.50	12.69	12.88	13.07	13.27	13.47	13.67	13.87	14.08	14.29	14.51
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.15	0.27	0.28	0.29	0.31	0.32	0.34	0.36	0.39	0.40	0.39
	Net	12.35	12.42	12.60	12.78	12.96	13.14	13.32	13.51	13.69	13.89	14.12
MacKay TS (T1)	Gross	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Northern Ave TS (T1)	Gross	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20

	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
	Net	0.20	0.20	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.19
Northern Ave TS (T2)	Gross	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.03	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.06
	Net	2.38	2.36	2.36	2.36	2.35	2.35	2.35	2.35	2.34	2.34	2.35
Chapleau MTS	Gross	4.12	4.03	4.13	3.92	4.41	4.33	4.36	3.70	4.01	3.96	3.96
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.05	0.09	0.09	0.09	0.10	0.10	0.11	0.10	0.11	0.11	0.11
	Net	4.07	3.94	4.04	3.83	4.31	4.23	4.25	3.61	3.89	3.84	3.85
Chapleau DS	Gross	9.9	10.5	12.1	12.3	14.4	14.5	14.6	14.7	14.8	14.9	15.0
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.12	0.22	0.26	0.27	0.33	0.35	0.37	0.39	0.41	0.42	0.40
	Net	9.76	10.31	11.88	11.99	14.07	14.16	14.25	14.33	14.41	14.50	14.62
Patrick St TS	Gross	149.7	159.9	167.2	164.6	165.6	165.8	165.3	165.6	165.6	165.5	165.5
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	149.70	159.90	167.20	164.60	165.60	165.80	165.30	165.60	165.60	165.50	165.50
Wallace Terrace CTS	Gross	15.60	15.80	15.70	15.70	15.70	15.70	15.70	15.70	15.70	15.70	15.70
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	15.60	15.80	15.70	15.70	15.70	15.70	15.70	15.70	15.70	15.70	15.70

Summer Non-Coincident Load Forecast [MW}

Transformer Station		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
St. Mary's MTS (T1/T2)	Gross	42.87	42.55	42.23	41.92	41.61	41.30	40.99	40.69	40.39	40.08	39.79
	CDM	19.61	19.61	19.61	19.61	19.61	19.61	19.61	19.61	19.61	19.61	19.61
	DG	0.50	0.91	0.91	0.92	0.97	0.99	1.03	1.06	1.11	1.12	1.07
	Net	22.76	22.04	21.72	21.39	21.04	20.70	20.36	20.02	19.67	19.36	19.11
St. Mary's MTS (T3/T4)	Gross	38.54	38.26	37.97	37.69	37.41	37.13	36.85	36.58	36.31	36.04	35.77
	CDM	19.66	19.66	19.66	19.66	19.66	19.66	19.66	19.66	19.66	19.66	19.66
	DG	0.45	0.81	0.82	0.83	0.87	0.89	0.93	0.96	1.00	1.01	0.96
	Net	18.43	17.78	17.49	17.19	16.88	16.57	16.27	15.96	15.65	15.37	15.15
Tarentorus MTS (T1/T2)	Gross	52.00	51.62	51.23	50.85	50.47	50.10	49.73	49.36	48.99	48.63	48.26
	CDM	19.75	19.75	19.75	19.75	19.75	19.75	19.75	19.75	19.75	19.75	19.75
	DG	0.61	1.10	1.10	1.12	1.17	1.21	1.25	1.29	1.35	1.36	1.30
	Net	31.64	30.77	30.38	29.98	29.55	29.14	28.72	28.31	27.89	27.51	27.22
Tarentorus MTS (T3/T4)	Gross	52.32	51.94	51.55	51.17	50.79	50.41	50.03	49.66	49.29	48.93	48.56
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.62	1.11	1.11	1.13	1.18	1.21	1.26	1.30	1.36	1.37	1.30
	Net	51.71	50.83	50.44	50.04	49.61	49.20	48.78	48.36	47.94	47.55	47.26
Andrews TS (T4)	Gross	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Net	0.24	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Batchawana TS	Gross	1.56	1.57	1.59	1.61	1.62	1.64	1.65	1.67	1.69	1.70	1.72
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05
	Net	1.54	1.54	1.56	1.57	1.58	1.60	1.61	1.63	1.64	1.65	1.67
DA Watson CTS (T1/T2)	Gross	5.11	5.16	5.22	5.27	5.32	5.37	5.43	5.48	5.54	5.59	5.65
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.06	0.11	0.11	0.12	0.12	0.13	0.14	0.14	0.15	0.16	0.15
	Net	5.05	5.05	5.11	5.15	5.20	5.24	5.29	5.34	5.39	5.43	5.50
Echo River TS (T1)	Gross	13.50	13.63	13.77	13.91	14.05	14.19	14.33	14.47	14.62	14.76	14.91
	CDM	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	DG	0.16	0.29	0.30	0.31	0.33	0.34	0.36	0.38	0.40	0.41	0.40
	Net	13.24	13.24	13.37	13.50	13.62	13.75	13.87	13.99	14.12	14.25	14.41
Goulais Bay TS (T1)	Gross	4.74	4.78	4.83	4.88	4.93	4.98	5.03	5.08	5.13	5.18	5.23
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.06	0.10	0.10	0.11	0.11	0.12	0.13	0.13	0.14	0.15	0.14
	Net	4.68	4.68	4.73	4.77	4.82	4.86	4.90	4.95	4.99	5.03	5.09
Hollingsworth TS (T2) Anjigami TS (T1)	Gross	12.15	12.28	12.40	12.52	12.65	12.77	12.90	13.03	13.16	13.29	13.43
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.14	0.26	0.27	0.28	0.29	0.31	0.32	0.34	0.36	0.37	0.36
	Net	12.01	12.02	12.13	12.24	12.36	12.46	12.58	12.69	12.80	12.92	13.07
MacKay TS (T1)	Gross	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Northern Ave TS (T1)	Gross	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
	Net	0.20	0.20	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.19
Northern Ave TS (T2)	Gross	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45

	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.03	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07
	Net	2.42	2.40	2.40	2.40	2.39	2.39	2.39	2.39	2.38	2.38	2.38
Chapleau MTS	Gross	2.36	2.19	2.02	2.06	2.51	1.90	1.62	2.06	2.05	2.02	2.02
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.03	0.05	0.04	0.05	0.06	0.05	0.04	0.05	0.06	0.06	0.05
	Net	2.33	2.14	1.98	2.02	2.45	1.85	1.58	2.01	2.00	1.96	1.96
Chapleau DS	Gross	7.4	8.0	9.6	9.7	11.8	11.9	12.0	12.1	12.1	12.2	12.3
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.09	0.17	0.21	0.21	0.27	0.29	0.30	0.32	0.33	0.34	0.33
	Net	7.31	7.83	9.39	9.49	11.53	11.61	11.70	11.78	11.77	11.86	11.97
Patrick St TS	Gross	147.8	156.4	160.5	160.6	160.8	160.6	160.7	160.7	160.7	160.7	160.7
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	147.83	156.41	160.52	160.59	160.84	160.65	160.69	160.73	160.69	160.70	160.70
Wallace Terrace CTS	Gross	15.33	15.43	15.70	15.49	15.54	15.50	15.53	15.55	15.52	15.53	15.53
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	15.33	15.43	15.70	15.49	15.54	15.50	15.53	15.55	15.52	15.53	15.53

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations
1.	Andrew TS
2.	Anjigami TS
3.	Batchawana TS
4.	Chapleau DS
5.	Chapleau MTS
6.	Clergue TS
7.	DA Watson TS
8.	Echo River TS
9.	Flakeboard CTS
10.	Gold Mines CTS
11.	Goulais Bay TS
12.	Hollingsworth TS
13.	MacKay TS
14.	Northern Ave TS
15.	Patrick St TS
16.	Rentech CTS
17.	St. Mary’s MTS
18.	Tarentorus MTS
19.	Third Line TS
20.	Wallace Terrace CTS
21.	Wawa TS

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	K24G	Third Line TS	MacKay TS	230
2.	P21G	Third Line TS	Mississagi TS	230
3.	P22G	Third Line TS	Mississagi TS	230
4.	P25W	Mississagi TS	Wawa TS	230
5.	P26W	Mississagi TS	Wawa TS	230
6.	T27P	Mississagi TS	Wells CGS	230
7.	T28P	Mississagi TS	Wells CGS	230
8.	W21M	Marathon TS	Wawa TS	230
9.	W22M	Marathon TS	Wawa TS	230
10.	W23K	MacKay TS	Wawa TS	230
11.	No.1 ALGOMA	Third Line TS	Patrick St TS	115
12.	No.2 ALGOMA	Third Line TS	Patrick St TS	115
13.	No.3 ALGOMA	Third Line TS	Patrick St TS	115
14.	ANDREWS1	Andrews TS	Andrews CGS	115
15.	CLERGUE1	Patrick St TS	Clergue TS	115
16.	CLERGUE2	Patrick St TS	Clergue TS	115
17.	No.1 COGEN	Clergue TS	Lake Superior CGS	115
18.	No.2 COGEN	Clergue TS	Lake Superior CGS	115
19.	GARTSHO1	MacKay TS	Gartshore SS	115
20.	GARTSHO2	MacKay TS	Gartshore SS	115

21.	GARTSHO3	Gartshore SS	Gartshore GS	115
22.	GL1SM	Third Line TS	St. Mary’s MTS	115
23.	GL1TA	Third Line TS	Tarentorus MTS	115
24.	GL2SM	Third Line TS	St. Mary’s MTS	115
25.	GL2TA	Third Line TS	Tarentorus MTS	115
26.	HARRIS1	Magpie SS	Harris CGS	115
27.	HIGHFAL1	Anjigami TS	DA Watson TS	115
28.	HIGHFAL2	Anjigami TS	DA Watson TS	115
29.	HLNGWTH1	Hollingsworth TS	Wawa TS	115
30.	HOGG1	Gartshore SS	Hogg CGS	115
31.	LEIGHBY1	Patrick St TS	Flakeboard CTS	115
32.	MAGPIE1	DA Watson TS	Magpie SS	115
33.	MISSION1	Magpie SS	Misson Falls CGS	115
34.	No.3 SAULT	MacKay TS	Third Line TS	115
35.	STEEPHL1	Magpie SS	Steephill Falls CGS	115
36.	W2C	Wawa TS	Chapleau DS	115

Appendix D: Lists of LDCs in the East Lake Superior Region

Sr. No.	**Company**	**Connection Type (TX / DX)**
1.	ALGOMA POWER INC.	TX
2.	CHAPLEAU PUC	TX
3.	HYDRO ONE NETWORKS INC. (DISTRIBUTION)	TX
4.	SAULT STE. MARIE PUC	TX

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

Appendix C

East Lake Superior Region Scoping Assessment

East Lake Superior Region Scoping Assessment Report

October 4, 2019

Table of Contents

Summary			
Region	East Lake Superior		
Start Date	July 2, 2019	**End Date**	October 3, 2019

1 Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB) regional planning process. The OEB endorsed the Planning Process Working Group's Report[1] 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 the regional planning process for the East Lake Superior (ELS) region was completed in December 2014. The 2014 Needs Assessment (NA) recommended that the potential needs identified be addressed through the development of localized wires-only solutions. Further coordinated regional planning did not proceed following publication of the 2014 ELS NA report.

The second cycle of regional planning for the ELS region was initiated in April 2019 with the NA process. The first step in the regional planning process, the NA was carried out by the Study Team (defined in Section 2), and the resulting NA[2] report – which identified needs to be considered in the Scoping Assessment to determine the appropriate process to address them – was completed and issued in June 2019.

During the Scoping Assessment, the Study Team reviewed the nature and timing of the known needs in the region to determine the most appropriate planning approach going forward. This process also identified needs and considerations that were not included in the NA. The planning approaches considered include:

- An Integrated Regional Resource Plan (IRRP) – where a greater range of options, including non-wires, are considered and/or closer coordination with communities and stakeholders is required;
- A Regional Infrastructure Plan (RIP) – which considers more straightforward wires-only options with limited engagement; or
- A local plan undertaken by the transmitter and affected local distribution company (LDC)– where no further regional coordination is needed.

Additional information on selecting a planning approach can be found in Appendix B.

This Scoping Assessment report:

- Lists the needs identified in the NA report;
- Describes additional needs and considerations not identified in the NA report;
- Defines the geographic grouping of the needs into sub-regions, as applicable;
- Determines the appropriate regional planning approach and scope for identified needs;
- Creates a terms of reference for an IRRP; and
- Establishes the composition of the IRRP Working Group.

[1] Planning Process Working Group Report to the Board - The Process for Regional Infrastructure Planning in Ontario

[2] Needs Assessment Report - East Lake Superior Region

2 Study Team

The Scoping Assessment was carried out by the Study Team:

- Independent Electricity System Operator (IESO) (project lead)
- Hydro One Networks Sault Ste. Marie LP (HOSSM) (transmitter)
- Hydro One Networks Inc. (HONI) (transmitter)
- Algoma Power Inc.
- Chapleau PUC
- Hydro One Distribution
- Sault Ste. Marie PUC (SSM PUC)

3 Categories of Needs, Analysis and Results

3.1 Overview of the Region

The ELS region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south.

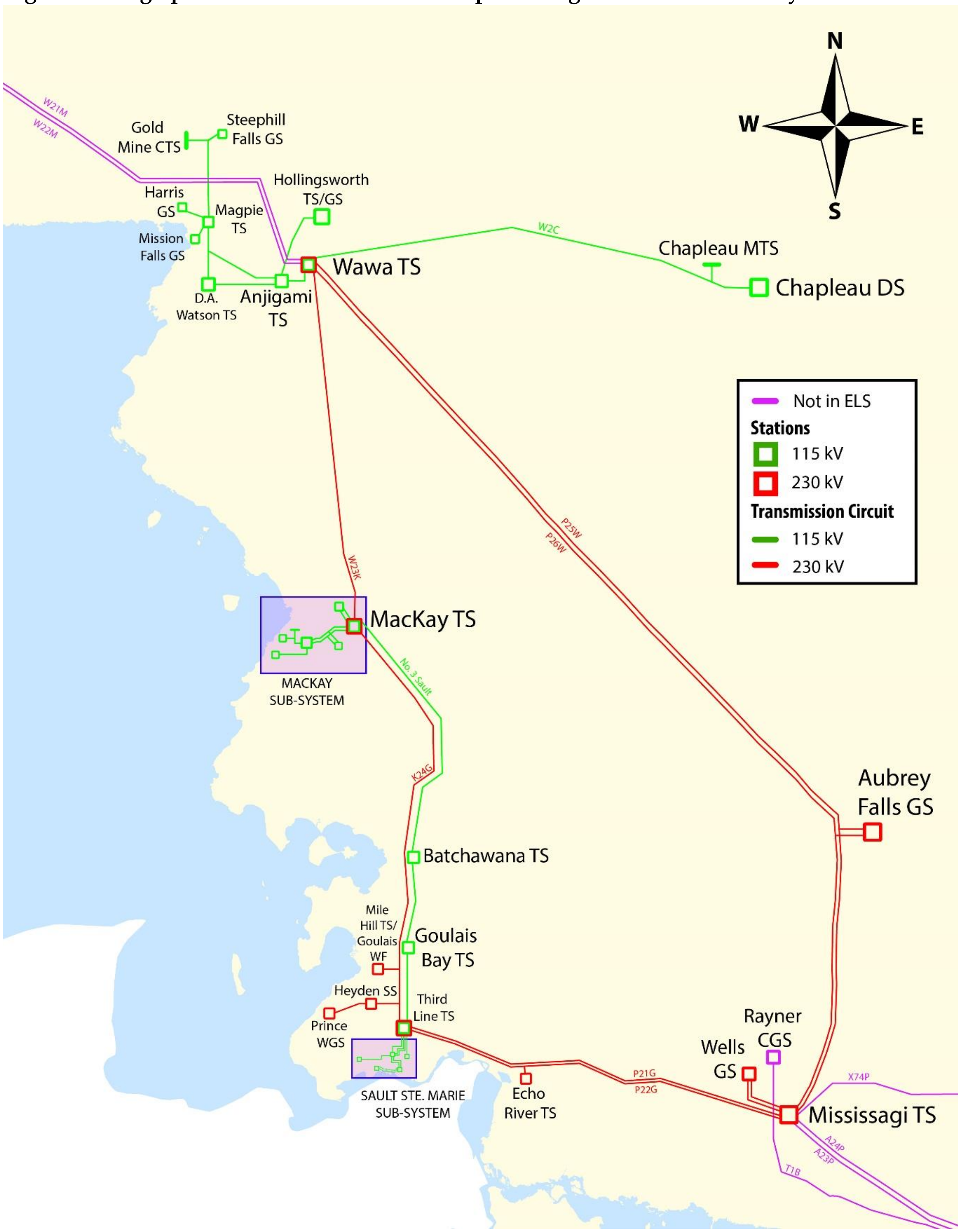
Electrical supply to the region is provided primarily through 230/115 kV autotransformers at Third Line TS, Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figures 1 and 2. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

The 230 kV transmission facilities in this area provide both bulk system and regional system functions. That is, in addition to delivering reliable supply to local customers, they also form part of an integrated network that enables the bulk transfer of electricity across the province. Although the bulk transmission system is not the focus of regional planning, it impacts how the system is modelled and studied.

The region has over 1,200 MW of generation, including numerous hydroelectric facilities, solar and wind farms and thermal generating facilities. The transmitters in the region are Hydro One Sault Ste. Marie LP (HOSSM) and Hydro One Networks Inc. (Hydro One); the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and Sault Ste. Marie PUC.

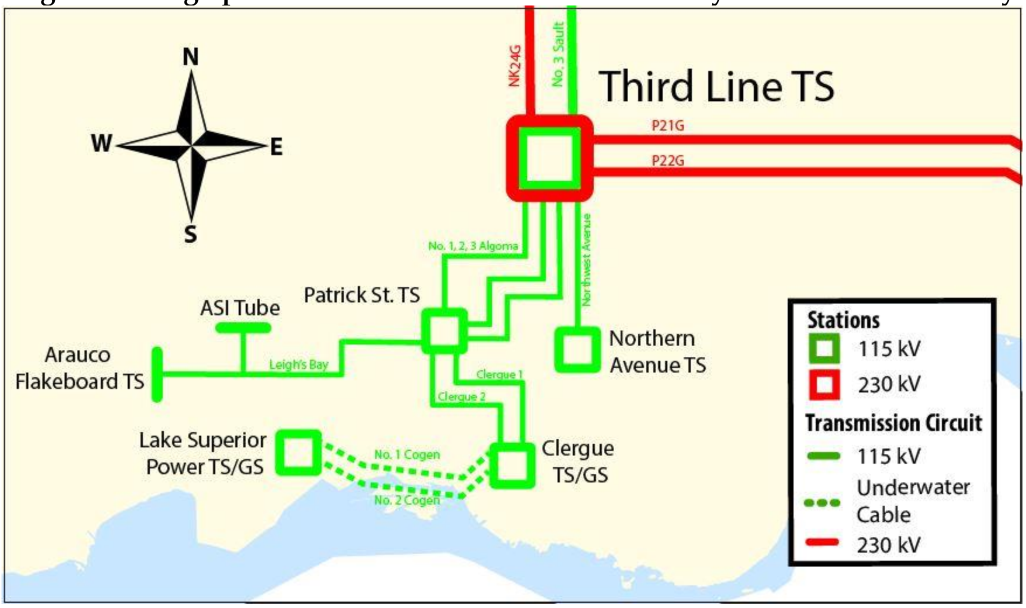
Geographic layouts of the electricity infrastructure supplying the region are shown in Figures 1, 2 and 3. An electrical single line diagram (SLD) for the same area is shown in Figure 4.

Figure 1: Geographical Area of the East Lake Superior Region with Electrical Layout



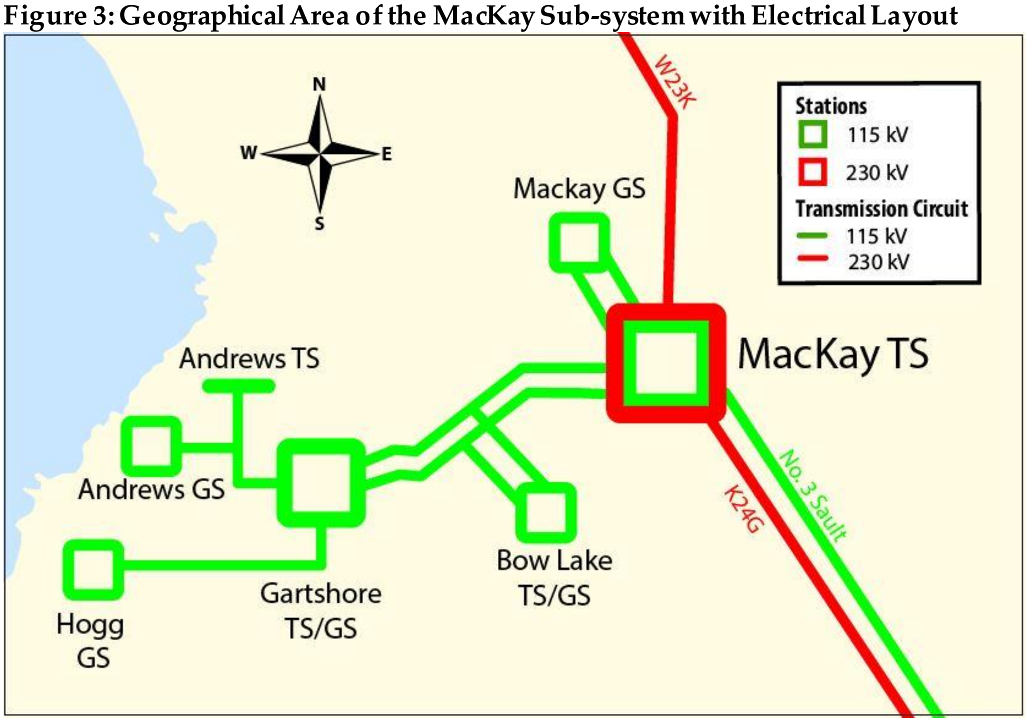
Source: IESO

Figure 2: Geographical Area of the Sault Ste Marie Sub-system with Electrical Layout



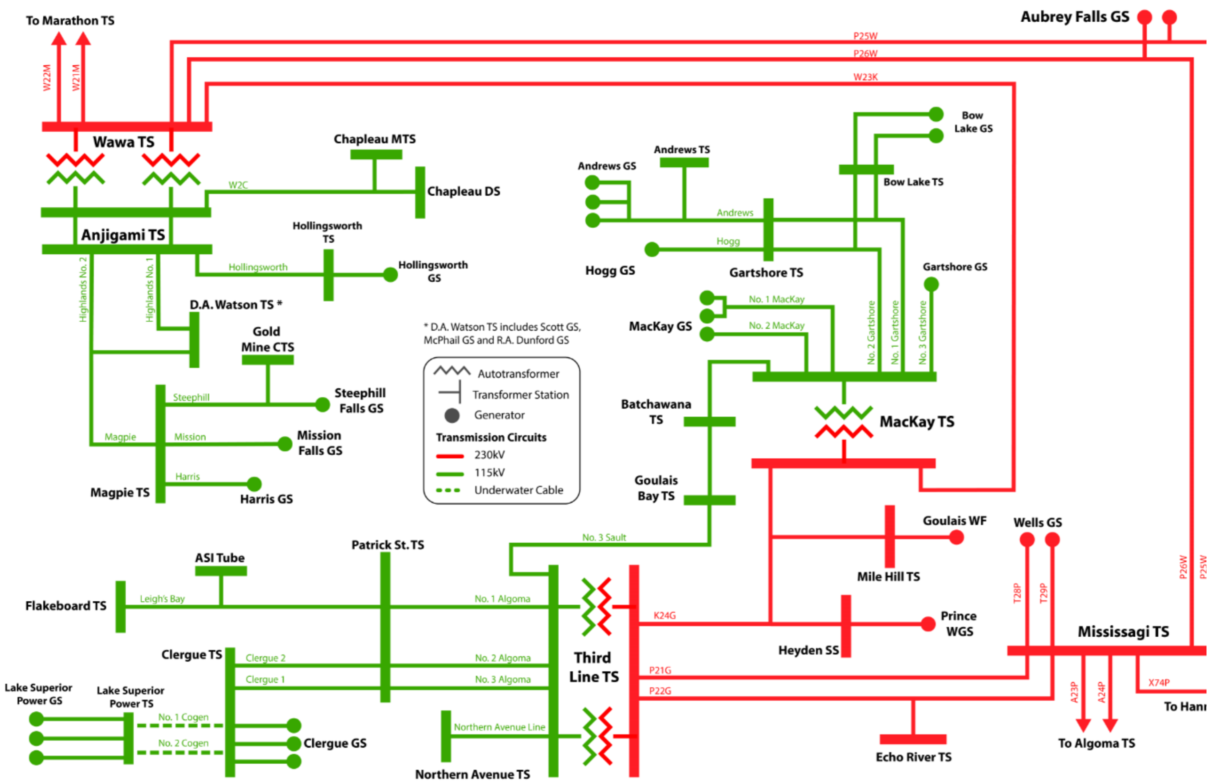
Source: IESO

Figure 3: Geographical Area of the MacKay Sub-system with Electrical Layout



Source: IESO

Figure 4: East Lake Superior Region Single Line Diagram



Source: IESO

3.2 Background

The first cycle of the regional planning process for the region was initiated by the former Great Lakes Power Transmission (GLPT) in October 2014 and completed in December 2014 with the publication of the 2014 NA report. The report identified a number of potential needs and recommended addressing them through the development of localized wires-only solutions. Further coordinated regional planning did not proceed following publication of the report.

In 2016, Hydro One acquired GLPT and renamed the company Hydro One Sault Ste. Marie LP. The second cycle of regional planning was kicked off by HOSSM in April 2019 and the 2019 NA report was published in June 2019. The needs identified in this report form the basis of the analysis for this Scoping Assessment and are discussed in further detail in Section 3.3.

3.3 Needs Identified

The 2019 NA report identified a number of needs based on studies performed during the needs assessment phase, current sustainment plans and a 10-year demand forecast. This section describes those needs.

3.3.1 Third Line TS Autotransformer Overload

Following the loss of one autotransformer at Third Line TS, the second autotransformer is expected to exceed its 10-day limited time rating (LTR) by 2022.

This need is exacerbated by the poor condition of the 115 kV circuit Sault No. 3, which is currently operated open until the conductor is replaced. The conductor is expected to be replaced by 2022 allowing it to be operated closed. This will reduce the need at Third Line TS, reducing loading on the autotransformers to 94 per cent of their 10-day LTR.

3.3.2 No. 1 Algoma Overload

No.1 Algoma is one of three 115 kV circuits supplying Patrick St TS from the Third Line 115 kV bus. Based on today's load, the loss of circuits No.2 Algoma and No.3 Algoma, or a breaker failure at Patrick St TS, can results in flows on No.1 Algoma exceeding the long-term emergency rating of the line.

3.3.3 Load Security and Restoration

Load restoration capability is the ability to restore power to those affected by a transmission outage within reasonable time frames. A restoration need emerges when load is interrupted following a transmission outage and supply cannot be restored within the timelines specified by the applicable planning criteria. These timelines are dependent on the amount of load being interrupted and proximity to maintenance crew and centres.

Load security needs emerge if the total amount of electricity supply at risk of interruption following a transmission outage exceeds the amounts permissible by the applicable planning criteria. The criteria identify areas where a supply outage could affect a vast number of customers, regardless of restoration time. Details on planning contingencies that must be considered, and associated restoration and security guidelines, are defined in Ontario Resource and Transmission Assessment Criteria (ORTAC).

The NA report identified load restoration needs following the loss of the step-down transformers at Andrew TS, Batchawana TS, Echo River TS or Goulais TS.

The NA report did not identify any load security needs; however subsequent studies identified a potential load security need[3] in the Sault Ste. Marie sub-system following the loss of both autotransformers[4] at Third Line TS.

3.3.4 End-of-Life Facility Needs

The need to replace aging transmission assets may present opportunities to better align investments with evolving power system priorities. This may involve up-sizing equipment in areas with capacity needs, downsizing or even removing equipment that is no longer required to supply needs.

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[3] Ontario Resource and Transmission Assessment Criteria, Section 7.1, Load Security Criteria

[4] North American Electric Reliability Corporation (NERC) Standard TPL 001-4, Category P6 – Multiple Contingency (Two overlapping singles)

Facilities anticipated to be approaching end of life are summarized in Table 1.

Table 1: End-of-Life Facilities

Facilities	Target Date
DA Watson TS – Protection Upgrade	2019 (underway)
Echo River TS – Breaker Replacement	2021
Sault No. 3 Conductor and Structure Replacement	2022
Third Line TS – Autotransformer T2 & Protection Replacement	2024
Patrick St TS – HV Breaker Replacement	2024
Batchawana TS / Goulais Bay TS – Station Refurbishment	2024
Northern Ave TS – Transformer T1 Replacement	2024
DA Watson TS – Metalclad Switchgear Replacement	2025
Clergue TS – Switchgear Replacement	2026

With the exception of the Sault No. 3 conductor and structure replacement, which is expected to result in significant system reliability benefits, the anticipated facility replacements listed in Table 1 are unlikely to impact other system needs.

3.4 Other Needs and Considerations

The Study Team also identified other needs not captured in the Needs Assessment:

3.4.1 Unbundling of Embedded Generation

There are over 60 MW of solar PV generation facilities embedded in region's LDC service territories (primarily located in the SSM PUC sub-system) that are not visible to the IESO or HOSSM. The historic output of these generation facilities needs to be separated or "unbundled" from the historic demand on the transmission system (i.e., grid demand) to determine the impact of the embedded (or distributed) generation on reducing grid demand and contributing to the reliability of the local transmission system.

3.4.2 Expiration of Generation Contracts

Between 2029 and 2031, over 120 MW of IESO-contracted generation facilities in the SSM PUC sub-system will expire. The impact on regional supply and reliability if these generators do not continue to operate after contract expiry will need to be determined.

3.4.3 Ferrochrome Smelter

In May 2019, a potential industrial customer and the city of Sault Ste. Marie announced their plan to site a ferrochrome production facility in the city, with construction planned to begin in 2025. Depending on the connection configuration of the facility, this project could impact the reliability of the local transmission system and may require regional coordination.

3.5 Analysis of Needs and Planning Approach

3.5.1 Needs to be Addressed in Local Planning

A local planning process is recommended to address the restoration needs identified at Andrew TS, Batchawana TS, Echo River TS and Goulais TS, described in Section 3.3.3, as well as the end-of-life needs described in Section 3.3.4. The Study Team will monitor the sustainment plans for these facilities to ensure they are coordinated with the IRRP.

3.5.2 Needs to be Addressed in Integrated Regional Resource Plan (IRRP)

The remaining needs discussed in Section 3.3:

- Have the potential to be addressed, in whole or part, by non-wires solutions;
- Could be impacted by varying bulk systems flows;
- Could be addressed in a coordinated manner (e.g., one solution may be able to address multiple needs);
- Impact multiple LDCs in the region and
- Require ongoing engagement and coordination with community-level energy planning activities.

As these needs should be addressed in a coordinated manner, the Study Team recommends an IRRP be undertaken for the region.

4 Conclusion

The Scoping Assessment concludes that:

1. A coordinated regional planning approached is required and an IRRP is recommended for the ELS Region to address the:
    - Third Line TS autotransformer overload
    - No. 1 Algoma overload
    - Load security needs described in Section 3.3.3
    - Other needs and considerations described in Section 3.4

   It is important to note that this list of needs is not exhaustive, as further detailed evaluation undertaken through the IRRP may identify new needs, particularly those requiring consideration for the longer term. Additionally, the IRRP process allows for continuous coordination of information related to needs, timing, and potential solutions with the ongoing bulk transmission studies and end-of-life activities in the region.

   The draft Terms of Reference outlining the scope, objectives and timeline of the ELS IRRP can be found in Appendix A.

2. Local planning is recommended to address both the restoration needs identified at Andrew TS, Batchawana TS, Echo River TS and Goulais TS, described in Section 3.3.3, and the end-of-life needs described in Section 3.3.4. The Study Team will monitor the sustainment plans for these facilities to ensure they are coordinated with the IRRP.

List of Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
ELS	East Lake Superior
EWTW	East West Transfer West
GLPT	Great Lakes Power Transmission
HONI	Hydro One Networks Inc.
HOSSM	Hydro One Sault Ste. Marie LP
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LTR	Limited Time Rating
MW	Megawatt
NERC	North American Electric Reliability Corporation
NUG	Non-Utility Generator
NA	Needs Assessment
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
TS	Transformer Station

Appendix A: The East Lake Superior 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 East Lake Superior (ELS) region.

Based on the needs identified through the Needs Assessment (NA) process, and further investigation through the Scoping Assessment, the Study Team recommended an integrated regional resource planning approach for the region.

The East Lake Superior Region

The ELS region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south.

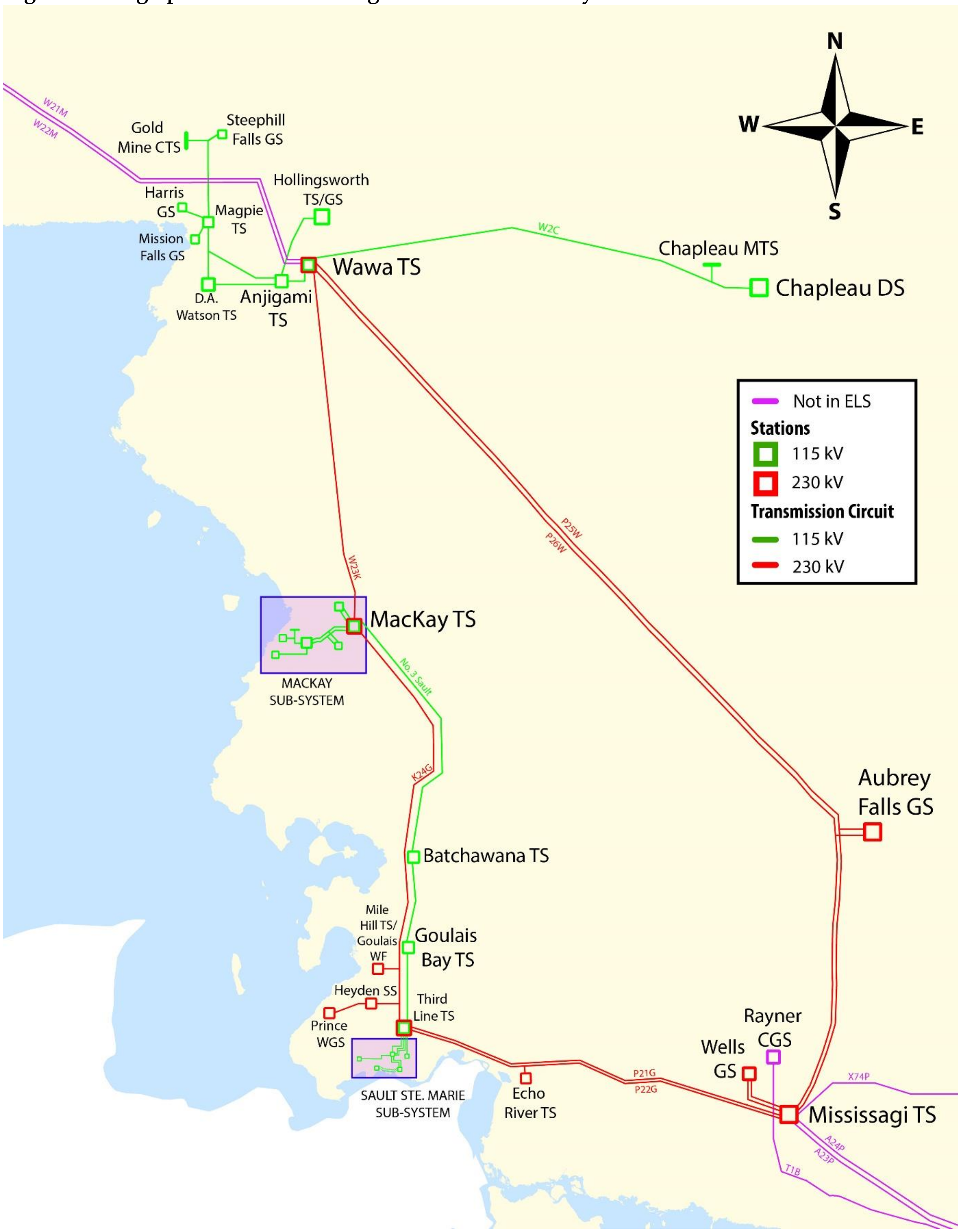
Electrical supply to the region is provided primarily through 230/115 kV autotransformers at Third Line TS, Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

The 230 kV transmission facilities in this area provide both bulk system and regional system functions. That is, in addition to delivering reliable supply to local customers, they also form part of an integrated network that enables the bulk transfer of electricity across the province. Although the bulk transmission system is not the focus of regional planning, it impacts how the system is modelled and studied.

The region has over 1,200 MW of generation, including numerous hydroelectric facilities, wind and solar farms and thermal generating facilities. The transmitters in the region are HOSSM and HONI; the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and SSM PUC.

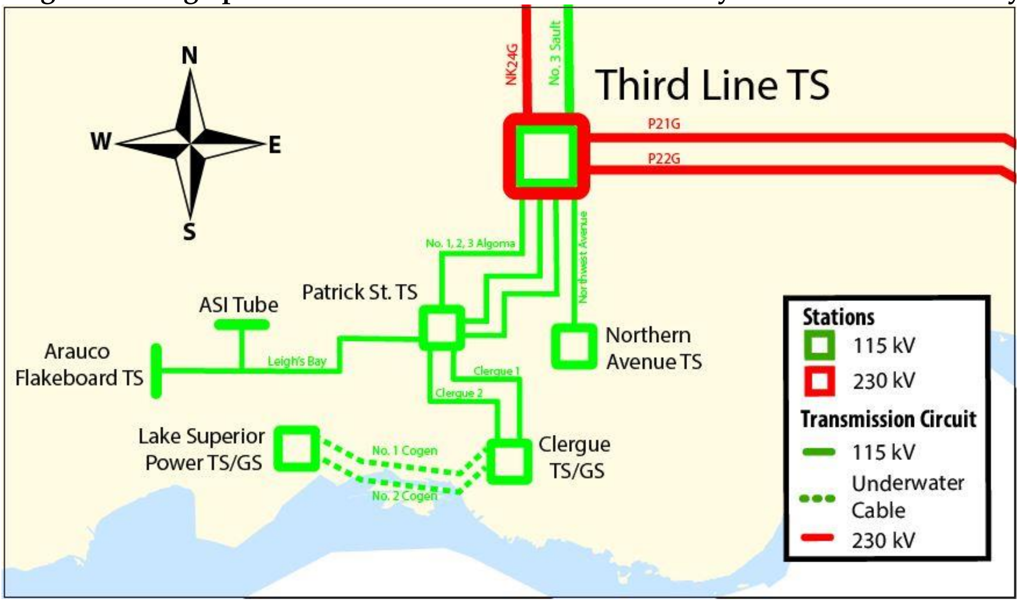
Geographic layouts of the electricity infrastructure supplying the region are shown in Figures 1, 2 and 3. An electrical single line diagram for the same area is shown in Figure 4.

Figure 1: Geographical Area of the Region with Electrical Layout



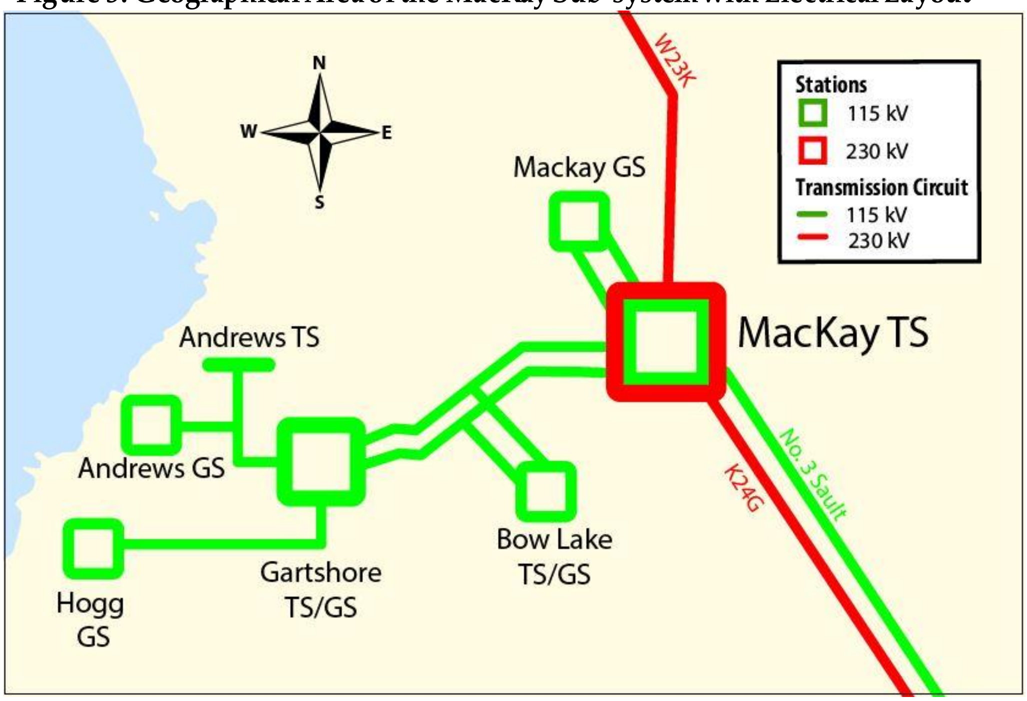
Source: IESO

Figure 2: Geographical Area of the Sault Ste. Marie Sub-system with Electrical Layout



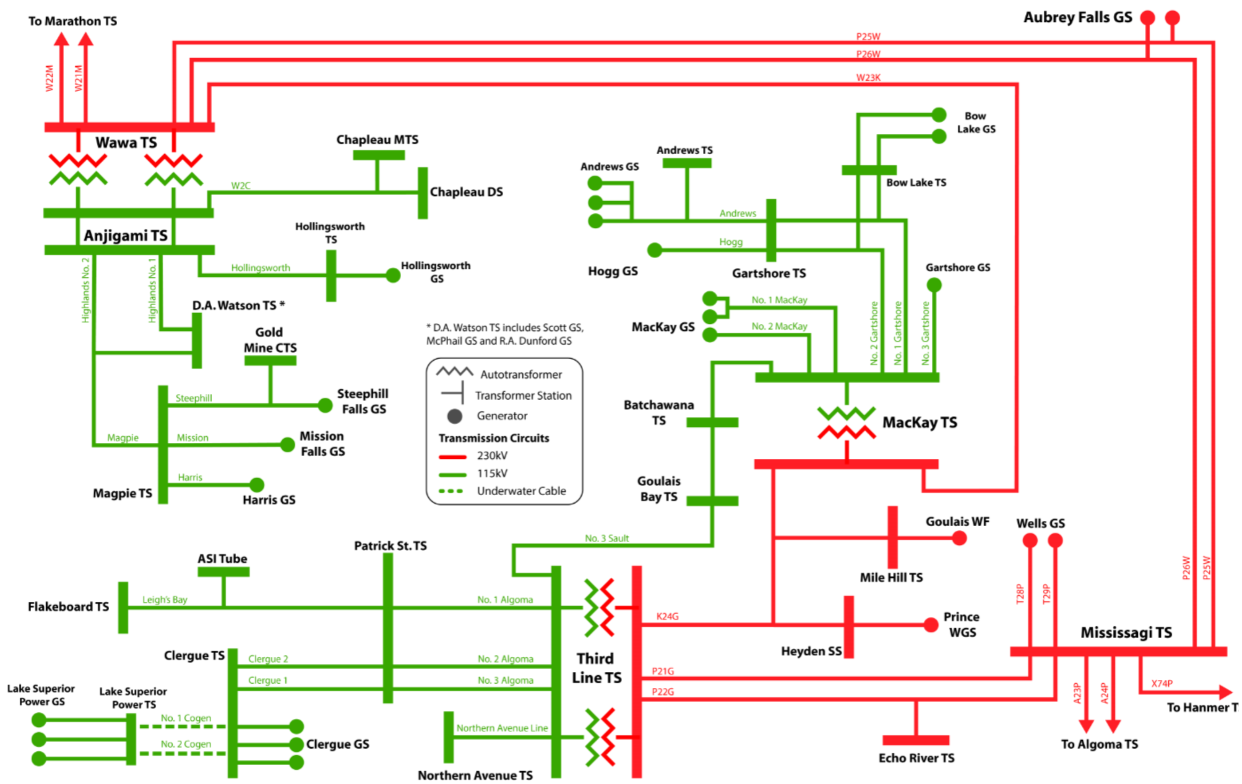
Source: IESO

Figure 3: Geographical Area of the MacKay Sub-system with Electrical Layout



Source: IESO

Figure 4: ELS Region Single Line Diagram



Source: IESO

Background

The first cycle of the ELS regional planning process was initiated by the former Great Lakes Power Transmission (GLPT) in October 2014 and completed in December 2014 with the publication of the 2014 NA report. That report identified a number of potential needs and recommended addressing them through the development of localized wires-only solutions – further coordinated regional planning did not proceed following its release.

In 2016, Hydro One acquired GLPT and renamed the company Hydro One Sault Ste. Marie LP. The second cycle of regional planning was kicked off by HOSSM in April 2019 and the NA report was published in June 2019. The needs identified in this report form the basis of the analysis for the Scoping Assessment and are discussed in further detail in Section 3 of the Scoping Assessment Report.

During the Scoping Assessment, the Study Team reviewed the nature and timing of known needs to determine both the most appropriate planning approach and the best geographic grouping of needs to create efficient study areas. The planning approaches considered include:

1. An IRRP – where a greater range of options, including non-wires, are to be considered as options and/or closer coordination with communities and stakeholders is required;

2. A RIP – which considers more straightforward wires-only options with limited engagement; or

3. A local plan undertaken by the transmitter and affected local distribution companies (LDCs) – where no further regional coordination is needed.

2. Objectives

The East Lake Superior IRRP will assess the adequacy of electricity supply to customers in the region and develop a set of recommendations to reliably maintain supply over the next 20 years. Specifically, the IRRP will:

- Assess the adequacy of electricity supply to customers in the ELS region over the next 20 years;
- Identify system reliability needs and develop and assess options to maintain system reliability;
- 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 regional needs, and develop a flexible, comprehensive, integrated electricity plan for East Lake Superior; and
- Develop an implementation plan with the flexibility to accommodate changes in key assumptions over time, while keeping options viable.

3. Scope

This IRRP will develop and recommend an integrated plan to meet region needs. The plan will be a joint initiative involving HOSSM, HONI, Algoma Power Inc., Hydro One Distribution, Sault Ste. Marie PUC and the IESO. These organizations will be defined as the Working Group for the ELS IRRP.

The plan will focus on:

- Third Line autotransformer overload need
- No.1 Algoma overload need
- Load security needs in the SSM PUC sub-system
- Unbundling of embedded generation
- Any additional needs that emerge in carrying out the IRRP

As with all IRRPs, the ELS IRRP will integrate forecast electricity demand growth, conservation and demand management (CDM); uptake of distributed energy resources (DERs); transmission and distribution system capability; relevant community plans; and bulk system developments as applicable. The IRRP will be carried out in a manner that allows for continuous coordination of information with other planning activities and processes.

The ELS IRRP process will involve:

1. Development of a stakeholder engagement plan.
2. Creation of an updated 20-year demand/load forecast for the region.

3. Assessment of the adequacy and reliability of the transmission system against established criteria and determination of the area's load meeting capability.
    a. Identify or confirm the system needs and adequacy of the area's load meeting capability for the study period using the updated load forecast.
    b. Confirm identified restoration and security needs using the updated load forecast.
    c. Collect information on any known reliability issues and load transfer capabilities from LDCs.
4. Development and assessment of options to mitigate identified needs. Options are evaluated using decision-making criteria, including but not limited to technical feasibility, economics, reliability performance, and environmental and social factors.
5. Development of the long-term recommendations and the implementation plan.
6. Completion of the IRRP report documenting near-, mid-, and long-term needs and recommendations.

Depending on the nature and the urgency of the electricity needs and risks identified, the IRRP could recommend a combination of the following:

- Active monitoring of load growth and equipment performance;
- Project development work to shorten lead times, without firm commitment for constructing the project;
- Commitment of project and proceed with project implementation (e.g., resources acquisition, transmission procurement, regulatory approval);
- Interim measures to manage near-term requirements, pending implantation of longer-term solutions;
- Pilots, studies and/or engagement to gather more information; and
- Coordination with other planning or related processes (e.g., community or bulk system planning).

Should the need for infrastructure investment be identified, the IRRP will provide a rationale and define high-level requirements to support project development and implementation to be carried out by other proponents. The outcomes from the ELS IRRP will help inform transmitter and LDC rate filings and any related transmission/resource acquisition processes that may result.

It is important to note that detailed discussion of acquisition mechanisms, cost allocation, cost recovery, siting, operations and implementation of recommended projects are beyond the scope of an IRRP.

In order to carry out this scope of work, the working group will consider the data and assumptions outlined in section 4.

4. Data and Assumptions

The plan may consider the following data and assumptions, where applicable:

- Demand data

  - Historical coincident and non-coincident peak demand information for the region
  - Impact of embedded generation on historic grid demand
  - Historical weather correction, for median and extreme conditions
  - Gross peak demand forecast scenarios, e.g., by region, sub-system, TS
  - Coincident peak demand data, including transmission-connected customers
  - Potential future load customers
- Conservation and demand management
  - Long-term conservation forecast for LDC customers based on planned provincial CDM activities
  - LDC programs, if applicable
  - Conservation potential studies, if available
- Local resources
  - Existing local generation, including distributed generation, 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 and municipal energy plans (e.g., Community Energy Investment Strategy for Waterloo Region)
  - Municipal growth plans
- Criteria, codes and other requirements
  - ORTAC
  - NERC and NPCC reliability criteria, as applicable
  - OEB Transmission System Code
  - OEB Distribution System Code
  - Other applicable requirements
- Existing system capability
  - Transmission line ratings as per transmitter records
  - Transformer ratings as per asset owner(s)
  - Load transfer capabilities
  - 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:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Sault Ste. Marie LP
- Hydro One Networks Inc.
- Algoma Power Inc.
- Hydro One Distribution
- Sault Ste. Marie PUC

<u>Authority and Funding</u>

Each organization involved in the study will be responsible for complying with any regulatory requirements applicable to the actions/tasks assigned to it under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

5. Engagement

Integrating early and sustained engagement with communities and stakeholders is a key component of the IRRP planning process.

The first step in engagement will consist of the development of a stakeholder engagement plan, which will be made available for comment before it is finalized. The scope of community and stakeholder engagement to be considered for this IRRP may include:

- Local electricity needs and considerations
- Status and key assumptions from community energy planning (e.g., energy intensity, electric vehicles and fuel switching scenarios)
- Status and key assumptions in growth plans and local economic developments (e.g., housing, population growth, commercial and industrial development)
- Impact of climate change in the East Lake Superior region
- Long-term land use and Infrastructure corridor plans
- Local interest in developing and implementing community-based energy solutions and factors that could facilitate or hinder the implementation of community-based energy solutions (e.g., existing or planned pilot projects, and the availability of local funding to support them; local policy/programs that enable/hinder project development; support from local utilities, community groups and government; and land use impacts and considerations.

6. Activities, Timeline and Primary Accountability

Table A-1: Summary of Expected IRRP Timelines and Activities

Activity		Lead Responsibility	Deliverable(s)	Approximate Time frame
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	July - Oct 2019
2	**Develop the Planning Forecast for the sub-region**			
	Establish historical coincident and non-coincident peak demand information	*IESO*	- Long-term planning forecast scenarios	Oct 2019 – Jan 2020
	Establish historical weather correction, median and extreme conditions	*IESO*		
	Establish gross peak demand forecast and growth scenarios	*LDCs*		
	Establish existing, committed and potential distributed generation	*LDCs*		
	Establish near- and long-term conservation forecasts based on planned energy-efficiency activities and codes and standards	*IESO*		
	Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Oct 2019 – Jan 2020
4	**Provide and review relevant community plans, if applicable**	*LDCs and IESO*	- Relevant community plans	Oct 2019 – Jan 2020

	Activity	Lead Responsibility	Deliverable(s)	Approximate Time frame
5	**Complete system studies to identify needs over a 20-year period** - Develop PSS/E base cases, including bulk system configuration and connectivity assumptions as identified in the key assumptions - Apply reliability criteria – as defined by NERC and NPCC and described in ORTAC – to demand forecast scenarios - Confirm and refine the need(s) and timing/magnitude	*IESO*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1 – Q2 2020
6	**Develop Options and Alternatives**			
	Develop conservation options, where applicable	*IESO and LDCs*	- Develop flexible planning options for forecast scenarios	Q2 – Q3 2020
	Develop local generation options, where applicable	*IESO and LDCs*		
	Develop transmission (see Action 7 below) and distribution options, where applicable	*All*		
	Develop options involving other electricity initiatives, where applicable (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	Integrate with bulk needs	*IESO*		
	Develop portfolios of integrated alternatives, where applicable	*All*		
	Technical comparison and evaluation	*All*		
7	**Plan and Undertake Community & Stakeholder Engagement**			
	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	Q3 2020
	Develop communications materials	*All*		ongoing
	Undertake community and stakeholder engagement	*All*		
	Summarize input and incorporate feedback	*All*		

Activity		Lead Responsibility	Deliverable(s)	Approximate Time frame
8	**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	Q3-Q4 2020
9	**Prepare the IRRP report detailing the recommended near-, medium- and long-term plan for approval by all parties**	*IESO*	- IRRP report	March 31 2021

Appendix B: Selecting a Regional Planning Approach

Needs identified through the NA process will be reviewed during the Scoping Assessment to determine whether a Local Plan (LP), Regional Infrastructure Plan (RIP), or Integrated Regional Resource Plan (IRRP) is more appropriate. Where multiple sub-regions are identified, each will be considered individually. A combination of LP, RIP and IRRP planning approaches could be selected in different sub-regions, although an urgent need for wires-type solution will typically trigger a hand-off letter instead.

Each of the three potential planning outcomes has different functions, and selection should be made based on a region's unique needs and circumstances. The criteria used to select the regional planning approach within each sub-region are consistent with the principles laid out in the PPWG Report to the Board,[5] and are discussed in this document to ensure consistency and efficiency throughout the Scoping Assessment.

IRRPs are comprehensive undertakings that consider a wide range of potential solutions, including conservation, generation, new technologies and wires infrastructure, to determine the optimal mix of resources to meet region needs over a 20-year time frame. RIPs are narrower in scope, focusing instead on identifying and assessing specific wires alternatives and recommending the preferred wires solution. In limiting the extent of its consideration to wires solutions that do not require further coordinated planning, LPs have the narrowest scope. An LP process is recommended when needs:

a) Are local in nature (only affecting one LDC or customer)
b) Involve limited investments of wires (transmission or distribution) solutions
c) Do not require upstream transmission investments
d) Do not require plan level community and/or stakeholder engagement and
e) Do not require other approvals such as an OEB Leave to Construct (S92) application or Environmental Approvals.

If coordinated planning is required to address identified needs, either an RIP or IRRP may be initiated. A series of criteria have been developed to assist in determining which planning approach is the most appropriate based on identified needs. In general, an IRRP is initiated when:

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[5] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

- A non-wires measure has the potential to meet or significantly defer the needs identified by the transmitter during the NA;
- Community or stakeholder engagement is required; or
- The planning process or outcome has the potential to impact bulk system facilities.

If the only feasible measures involve new/upgraded transmission and/or distribution infrastructure, with no requirement for engagement or anticipated impact on bulk systems, an RIP will be selected instead.

Wires-type transmission/distribution infrastructure solutions refer, but are not limited to:

- Transmission lines
- Transformer/switching stations
- Sectionalizing devices, including breakers and switches
- Reactors or compensators
- Distribution system assets

Determining the feasibility of non-wires alternatives to meet identified needs should also consider issues such as timelines for implementing solutions. For instance, if a need has been identified as immediate or near-term, non-wires solutions that rely on lengthy development and roll-out periods may not be feasible.

Appendix D

East Lake Superior Region Integrated Regional Resource Plan

Integrated Regional Resource Plan

East Lake Superior Region
April 2021

ieso
Connecting Today.
Powering Tomorrow.

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List of Acronyms

BKF	Breaker Failure
CDM	Conservation and Demand Management
DG	Distributed Generation
ELS	East Lake Superior
EWT	East West Transfer
EWTE	East West Transfer East
EWTW	East West Transfer West
GLPT	Great Lakes Power Transmission
HONI	Hydro One Networks Inc.
HOSSM	Hydro One Sault Ste. Marie LP
IESO	Independent Electricity System Operator
IRRP	Independent Electricity Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MW	Megawatt
NERC	North American Electric Reliability Corporation
NUG	Non-Utility Generator
NA	Needs Assessment
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board

ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
STE	Short Term Emergency
TS	Transformer Station
TTC	Total Transfer Capability

Integrated Regional Resource Plan
ELS

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 East Lake Superior (ELS) Region Technical Working Group which included the following members:

- Independent Electricity System Operator
- PUC Distribution Inc.
- Algoma Power Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Hydro One Sault Ste. Marie LP

The Technical Working Group assessed the reliability of electricity supply to customers in the ELS region over a 20-year period beginning in 2020 and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time and align with IESO's bulk planning study for the broader region commencing in 2021.

The ELS Technical 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 as required.

The ELS region Technical Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

This report is organized as follows:

- The plan is introduced in Section 1;
- A summary of the recommended plan for the ELS 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 ELS Region and the study scope are discussed in Section 4;
- Demand forecast, conservation and distributed generation assumptions are described in Section 5;
- Electricity needs in the ELS Region are presented in Section 6;
- Options and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement to date and moving forward is provided in Section 8;
- A conclusion is provided in Section 9.

1. Introduction

This IRRP for the ELS region addresses the regional electricity needs over the study period, i.e., from 2020 to 2040. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of the Technical Working Group composed of IESO, PUC Distribution Inc., Algoma Power Inc., Hydro One Networks Inc. (Distribution), Hydro One Networks Inc. (Transmission) and Hydro One Sault Ste. Marie LP.[1]

In Ontario, planning to meet the electrical 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 the 21 electricity planning regions across Ontario, including the ELS region, at least once every five years.

In this region, the electrical load is comprised of industrial, commercial and residential users and is winter peaking. The ELS region is supplied through 230/115 kV autotransformers at Third Line Transformer Station (TS), Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

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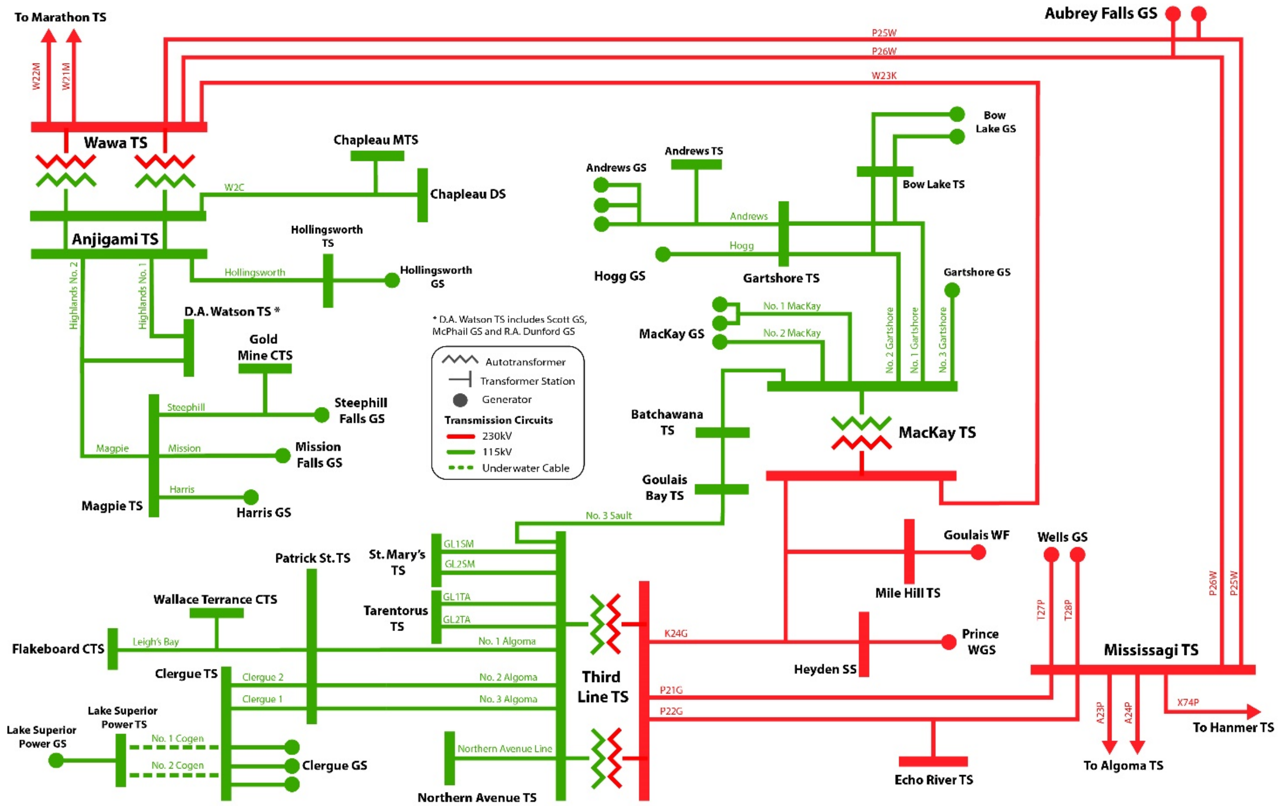
[1] Hydro One Distribution participated on behalf of Chapleau PUC

Figure 1 | ELS Single Line Diagram



2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the ELS region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of options, representing alternative ways to meet the needs, that considers: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

While the demand forecast underpinning this plan is relatively flat over the 20-year planning horizon, there is potential for significant growth in industrial loads directly connected to the high voltage transmission system which can impact the bulk transmission system in the broader region. Accordingly, this high industrial growth is not included in this plan and will be studied as part of the IESO's bulk planning study, starting in 2021.

While the bulk planning study will consider high industrial growth, some of the needs identified as part of this IRRP are linked to the bulk transmission system in the broader region and should thus be considered as part of this study to ensure a coordinated approach. As such, this IRRP has identified the needs for which this coordination is required and has recommended that they be carried forward into the IESO's bulk planning study. For those needs that are not directly linked to the bulk transmission system in the broader region, this IRRP has identified specific recommendations to address them.

2.1 Recommendations of the Plan

The recommended actions to address the region's needs are summarized in Table 2.1 below, together with the details of their implementation.

Table 2.1 | Implementation of Recommended Plan for ELS Region

Need	Recommendation	Lead Responsibility	Required By
Loss of one Third Line TS autotransformer causes the companion autotransformer to be loaded close to its capacity	Monitor load and supply in the ELS region	IESO/HOSSM	Immediately and Ongoing

Need	Recommendation	Lead Responsibility	Required By
Loss of P21G and P22G circuits causes voltage collapse at Third Line TS and other ELS stations	Enable remote arming of GLP Instantaneous Load Rejection Scheme for P21G and P22G double contingency for operational efficiency over manual arming	Hydro One	Immediately
Loss of two Algoma circuits or a Patrick St TS 214 BKF results in thermal overload of the remaining Algoma circuit	Implement automatic load rejection scheme at Patrick St TS	HOSSM	Immediately
During an outage of P25W or P26W circuits, a loss of the K24G circuit results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
During an outage of one of the Third Line TS autotransformers, a loss of the companion autotransformer results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa	Hydro One to work with the LDC to build a new 115/44 kV station that will tap off Hollingsworth 115 kV circuit to accommodate the load increase	HOSSM	2024

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 and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, develops and 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 transmitter(s) and LDC(s) 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.

Regional Planning is one type of electricity planning in Ontario; other types include Bulk System Planning and Distribution System Planning (local planning). A key benefit of the regional planning process is that it provides an opportunity for the entities leading these various planning activities to develop efficient planning outcomes when considering the needs and alternatives as a whole.

Further details on the regional planning process and the IESO's approach to regional planning can be found in Appendix A.

The IESO has also finalized a review of the Regional Planning Process to consider lessons learned and findings from the previous cycle of regional planning and other regional planning development initiatives, such as pilots and studies. The recommendations and next steps from this review are available in the Regional Planning Process Review Final Report which is published on the IESO's website.

3.2 IESO's approach to Regional Planning

In assessing electricity system needs for a region over a 20-year period, IRRPs enable 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.

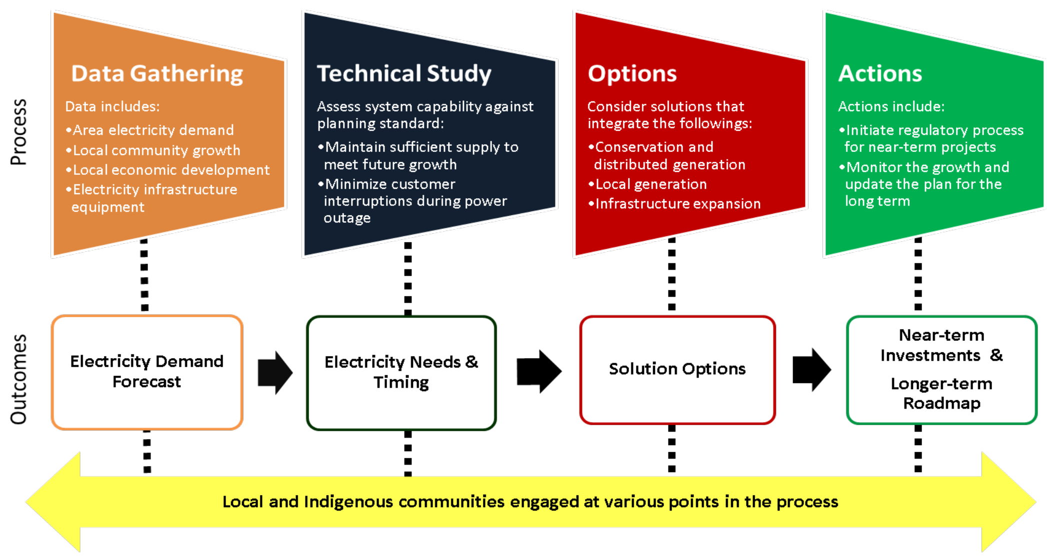
In developing this IRRP, the Technical Working Group followed a number of steps (See Figure 3.2) including:

- Data gathering, including development of electricity demand forecasts;
- Conducting technical studies to determine electricity needs and the timing of these needs;
- Developing and evaluating potential options; and
- Preparing a recommended plan including actions for the near and longer term.

Throughout this process, engagement was carried out with stakeholders with an interest in the area.

The IRRP documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the various entities responsible for plan implementation. The IRRP helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

Figure 3.2 | Steps in the IRRP Process



3.3 ELS Technical Working Group and IRRP Development

The second cycle of regional planning in ELS was initiated in April 2019. In June 2019, Hydro One published the Needs Assessment report for the region which included input from the IESO, Algoma Power, Chapleau PUC, Hydro One Distribution, Hydro One Sault Ste. Marie and PUC Distribution Inc. The Needs Assessment report identified needs which required coordinated regional planning and, therefore, the IESO conducted a Scoping Assessment process and issued the Scoping Assessment Outcome Report in October 2019. This report ultimately recommended that an IRRP be conducted for the region to assess the needs requiring a coordinated regional approach.

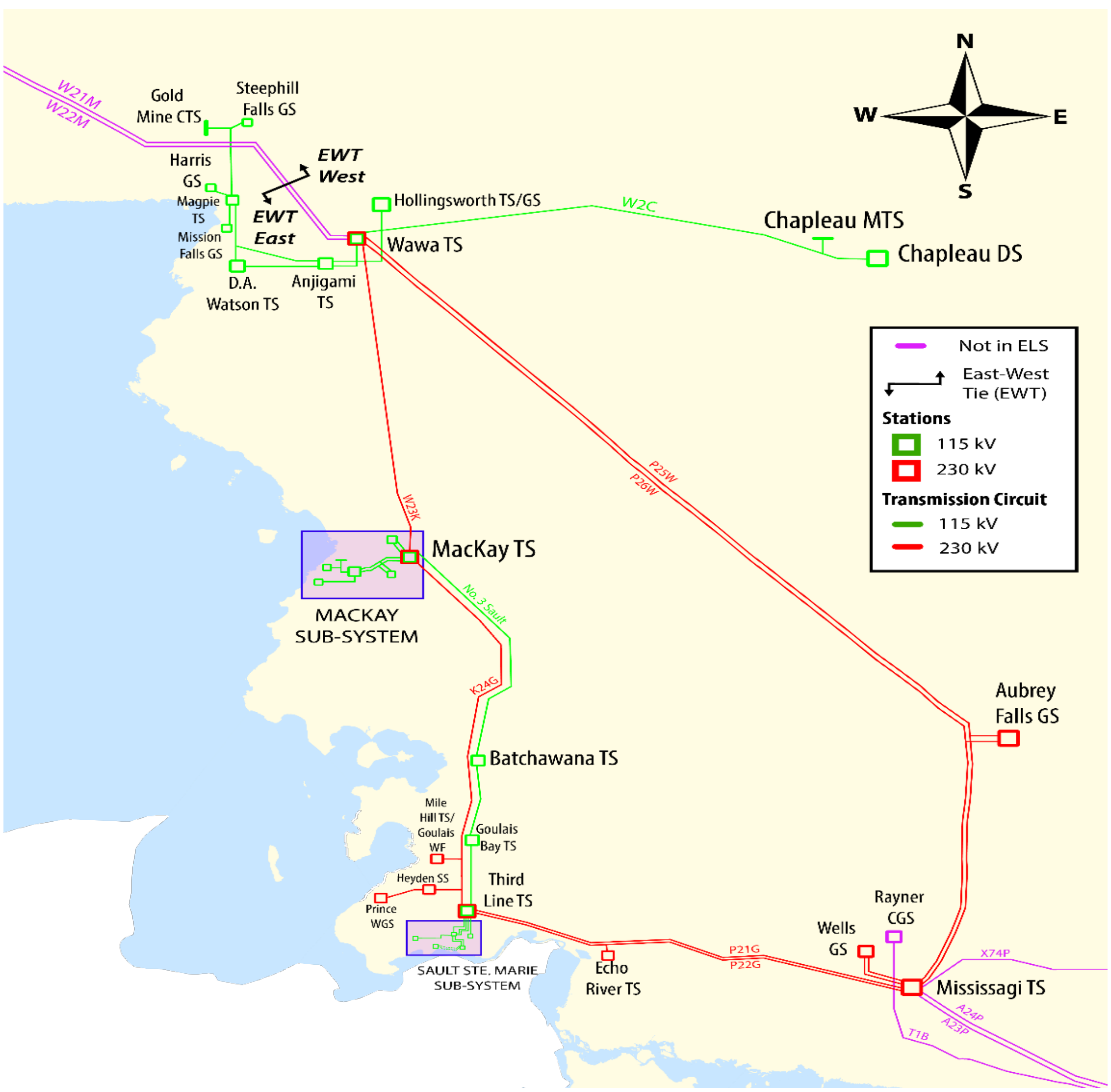
The Technical Working Group then gathered data, performed technical studies to identify the region's reliability needs, evaluated options to address the needs and developed the recommended actions included in this IRRP.

4. Background and Study Scope

In geographical terms, the region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south as shown in Figure 4.1 below.

The region is supplied from a combination of local generation and connection to the Ontario electricity grid via a network of 230 kV and 115 kV transmission lines and stations. The transmitters in the region are Hydro One Sault Ste. Marie LP (HOSSM) and Hydro One Networks Inc. (Hydro One); the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and PUC Distribution Inc.

Figure 4.1 | ELS Transmission System



4.1 History of Electricity Planning in the ELS Region

This is the second cycle of regional planning for the ELS region. In the first cycle, a Needs Assessment was completed by Hydro One in late 2014 which did not identify electricity needs in the next 10 years requiring regional coordination. The Needs Assessment report identified issues for which local wires only solutions were to be developed.

4.2 Study Scope

This IRRP was prepared by the IESO on behalf of the Technical Working Group and recommends options to meet the electricity needs of the ELS region of the study period with a focus on providing an adequate, reliable supply to support community growth. The objectives and scope of this IRRP are set out in the Scoping Assessment, together with the roles and responsibilities of the Technical Working Group members.

The transmission facilities in-scope of the ELS IRRP are described below:

- 230/115 kV autotransformers- Third Line TS, Wawa TS, Mackay TS;
- 230 kV connected stations- Mississagi TS, Echo River TS, Heyden CSS, Mile Hill CTS;
- 115 kV connected stations- Anjigami TS, Chapleau MTS, Chapleau DS, Hollingsworth TS, DA Watson TS, Magpie TS, Gold Mine CTS, Flakeboard CTS, Wallace Terrance CTS, Patrick St TS, Lake Superior Power TS, Clergue TS, Northern Avenue TS, Goulais Bay TS, Batchawana TS, Gartshore TS, Andrews TS and Bow Lake TS, St. Mary's MTS, Tarentorus MTS;
- 230 kV transmission lines – P25W, P26W, W23K, K24G, P21G, P22G, T28P, T27P;
- 115 kV transmission lines – W2C, High Falls No. 1. High Falls No. 2, Magpie, Harris, Mission, Steephill, Andrews, Hogg, No. 1 Mackay, No. 2 Mackay, No. 1 Gartshore, No. 2 Gartshore, No. 3 Gartshore, Sault No.3, No. 1 Algoma, No. 2 Algoma, No. 3 Algoma, Clergue 1, Clergue 2, Leigh's Bay, No. 1 Cogen, No. 2 Cogen, GL1SM, GL2SM, GL1TA, GL2TA;
- 115 kV generation assets – Hollingsworth GS, Harris GS, Mission Falls GS, Steephill Falls GS, Andrews GS, Bow Lake GS, Hogg GS, Gartshore GS, Mackay GS, Clergue GS, Lake Superior CGS;
- 230 kV generation assets – Aubrey Falls GS, Wells GS; and
- Storage – Sault Ste. Marie Energy Storage at St. Mary's MTS.

The ELS 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 NERC standards and 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 HOSSM and Hydro One;
- 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.

4.2 IESO’s Bulk Planning Study

While the demand forecast underpinning this plan is relatively flat over the 20-year planning horizon, there is potential for significant growth in industrial loads directly connected to the high voltage transmission system which can impact the bulk transmission system in the broader region. Accordingly, this high industrial growth is not included in this plan and will be studied as part of the IESO’s bulk planning study, starting in 2021.

While the bulk planning study will consider high industrial growth, some of the needs identified as part of this IRRP are linked to the bulk transmission system in the broader region and should thus be considered as part of this study to ensure a coordinated approach. As such, this IRRP has identified the needs for which this coordination is required and has recommended that they be carried forward into the IESO’s bulk planning study. For those needs that are not directly linked to the bulk transmission system in the broader region, this IRRP has identified specific recommendations to address them.

5. Electricity Demand Forecast

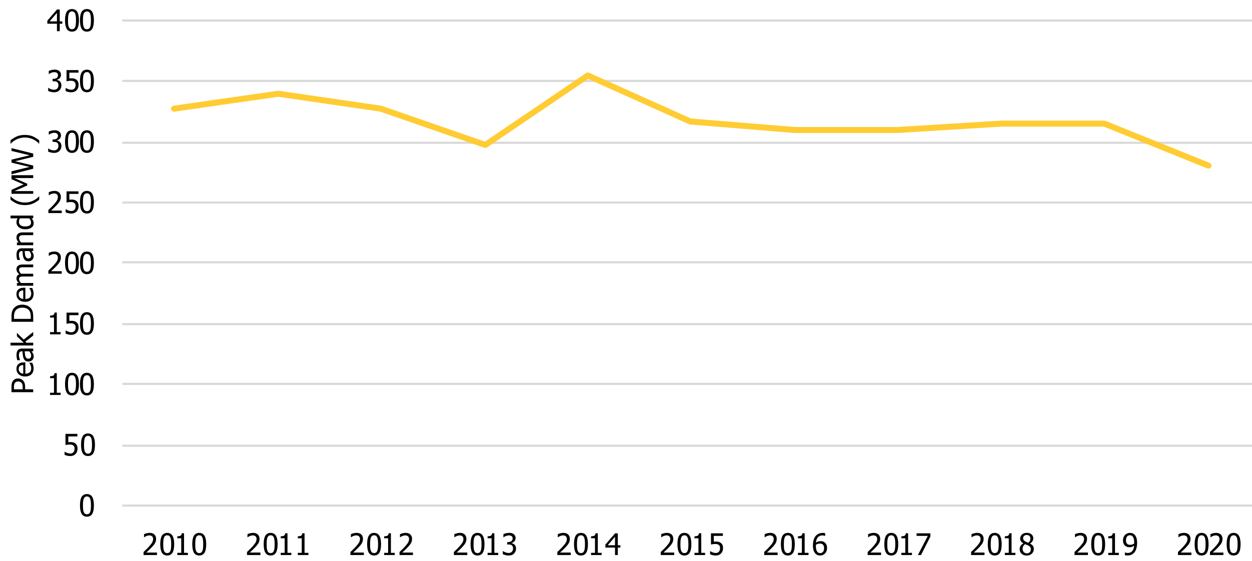
A fundamental consideration in any electricity supply study is how much electricity will be required in the region over the study period. This section describes the development of the demand forecast within the ELS Region over the 20-year study period, highlighting the assumptions made for peak demand load forecasts (i.e., the maximum demand in MW forecasted to occur in each year), including the expected contribution of conservation and demand management, and Distributed Generation (DG) to reducing peak demand. When combined, these factors produce the net peak demand forecast used to assess the electricity needs of the area over the planning horizon.

To evaluate the reliability of the electricity system, regional planning is typically concerned with the coincident peak demand for a given area, or the demand observed at each station for the hour of the year in which overall demand in the study area is at a maximum. This represents the moment when assets are at their most stressed, and resources generally the most constrained. This differs from a non-coincident peak, which is the sum of individual peaks at each station, regardless of whether these peaks occur at different times.

Within the ELS region, the peak loading hour for each year typically occurs in the evening in the winter season and is driven by electrical heating demand in the residential sector as access to natural gas is limited in the area. In addition, the region is home to a number of large industrial customers, in the manufacturing and mining sectors, that consume large amounts of energy (i.e., the total amount of electricity flowing through the system over time and typically measured in MWh) over the course of a year. Energy consumption by these customers can be impacted by economic conditions, such as commodity prices. Due to the large number of industrial customers in the region whose peaks do not coincide with the residential customers, this plan assumed non-coincident peak load at each station except for the two transformer stations owned by PUC Distribution Inc. since they have the ability to transfer loads between their two stations.

Historical winter peak demand in the region has decreased from 355 MW in 2014 to 280 MW in 2020. This decline is primarily due to the closure of large industrial customers in the pulp and paper sector. COVID-19 is also expected to have contributed to the decline observed in 2020. Figure 5.0 shows the historical winter peak demand in the ELS region.

Figure 5.0 | Historical Peak Demand in the ELS Region (2010-2020)



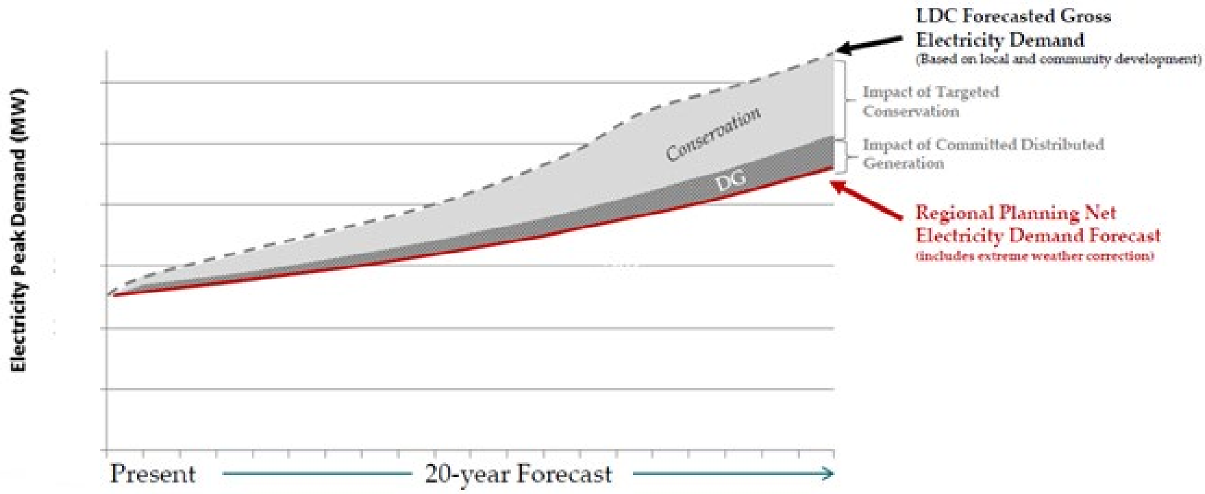
5.1 Methodology for Preparing the Forecast

A 20-year non-coincident peak demand forecast was developed for the region to assess its reliability needs. The steps taken to develop this forecast are illustratively shown in Figure 5.2 and described below.

1. The IESO weather-corrected the most recent year's demand data (2018 at the time of forecast development) to create a forecast "start" point based on expected peak demand under median (or "most likely") weather conditions. This "start" point was provided to the LDCs to help inform the basis of their forecasts.
2. Each participating LDC developed its own 20-year demand forecast for each station in their service areas. Since LDCs have the closet relationship to customers, connection applicants, and municipalities and communities, they have a better understanding of future local load growth and drivers than the IESO. The IESO typically carries out load forecasting at the provincial level.
3. The IESO modified the LDC forecasts provided for each station to reflect extreme weather conditions and subtracted the estimated peak demand impacts of provincial conservation policy and committed DERs that may have been contracted through previous provincial programs such as the Feed-in Tariff (FIT) and microFIT programs.

The result of these steps was a station-by-station outlook of net annual peak demand over the study period. Additional details on the demand forecast process, including station-level forecasts, may be found in Appendix B.

Figure 5.1 | Illustrative Development of Net Demand Forecasts



5.1.1 Conservation Assumptions in the Forecast

Conservation is achieved through a mix of program-related activities and mandated efficiencies from building codes and equipment standards. Future CDM savings for the ELS Region have been applied to the peak gross demand forecast and take into account both policy-driven and funded EE through the provincial Interim Framework, which came into effect on April 1, 2019 (estimated peak demand impacts due to program delivery to the end of 2020). The Interim Framework has targets to achieve annual energy savings of 1.4 TWh and peak demand reductions of 189 MW.[2] Expected peak demand impacts due to building codes and equipment standards were also included for the duration of the forecast.

Once sectoral gross forecast demand at each TS was estimated, peak-demand savings were estimated for each conservation category – building codes and equipment standards, and delivery of funded CDM programs. Due to the unique characteristics and available data associated with each category, estimated savings were determined separately. The total conservation savings included in the net demand forecast are provided in Table 5.1.1 below. These savings are broken down by residential, commercial and industrial customer sectors.

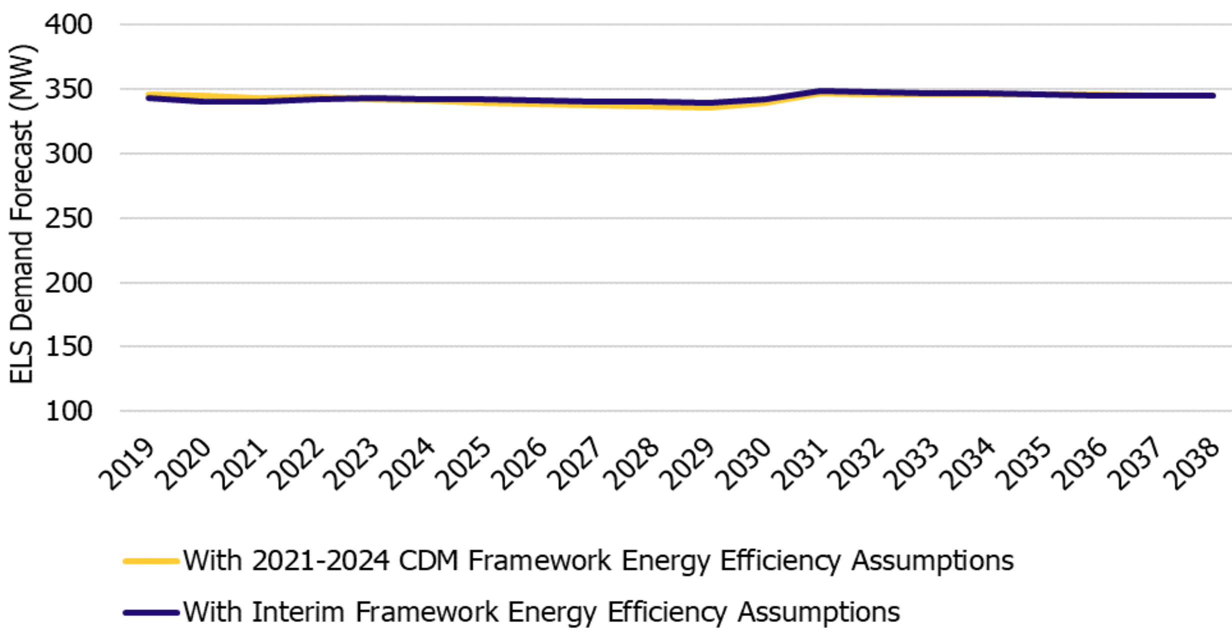
Table 5.1.1 | Peak Demand Savings due to Codes and Standards and Funded CDM Programs (MW)

Year	2020	2025	2030	2038
Residential	0.6	0.9	2.7	5.3
Commercial	3.8	2.4	1.1	0.4
Industrial	0.0	0.0	0.0	0.0
Total	4.5	3.3	3.8	5.7

[2] https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/2021-2024-Conservation-and-Demand-Management-Framework

After the demand forecast was developed for the ELS IRRP, the new 2021-2024 CDM framework starting in January 2021 was announced. While the Interim Framework assumptions were used in the development of the planning forecast, a sensitivity using the assumptions of the 2021-2024 CDM Framework was conducted. This sensitivity showed minimum impact (less than 2% difference) to the region's demand forecast as shown in Figure 5.1.1.

Figure 5.1.1 | Comparison of Planning Demand Forecast with Interim Framework Energy Efficiency Assumptions vs 2021-2024 CDM Framework Energy Efficiency Assumptions



5.1.2 Distributed Energy Resources Assumptions in the Forecast

After applying the conservation savings to the gross demand forecast as described above, the forecast is further reduced by the expected peak contribution of existing and contracted DERs in the area. The peak demand impact of DERs that were connected to the system at the time of forecast development were accounted for in the IRRP. Given the difficulty of predicting future DER uptake, no assumptions have been made regarding future DER growth.

While the FIT Program and other procurements for small-scale generation have ended, the IESO remains committed to transitioning to the long-term use of competitive mechanisms to meet Ontario's resource adequacy needs through the Resource Adequacy Framework. In addition, the IESO is engaged in several activities to help reduce the barriers to DERs as alternatives to wires-based solutions. Additional details of these activities are included in the IESO's Regional Planning Process Review Report.

Based on the IESO contract list as of March, 2019, DERs in the ELS region are expected to offset demand by 14.6 MW of winter effective capacity at the start of the study period. As the DER contracts expire over the planning period, their contribution is removed accordingly. The DERs included in this IRRP are distribution connected from the following stations:

- Echo River TS
- Batchawana TS
- Goulais Bay TS
- Patrick St TS
- St. Mary's MTS
- Tarentorus MTS
- Chapleau DS
- DA Watson TS

Peak contribution factors reflecting the portion of installed capacity available at the time of peak were calculated for the DERs in the region using historical hourly generation where available; these factors are shown in Table 5.1.2 below.

Table 5.1.2| Peak Contribution Factors (%)

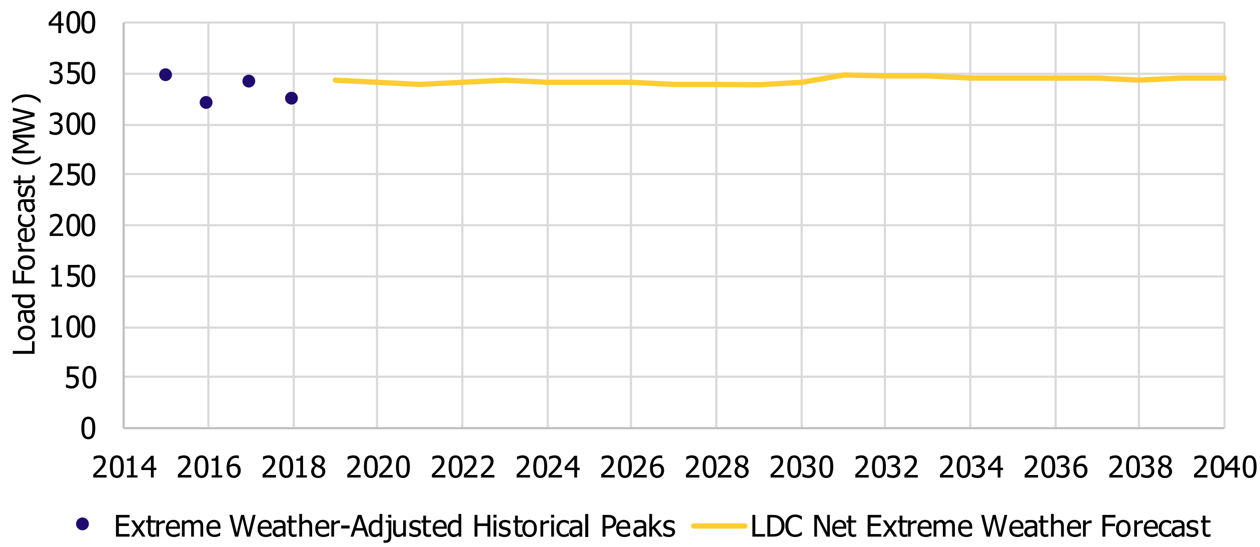
Fuel Type / Facility	Summer Contribution (%)	Winter Contribution (%)
Solar[3]	69	19
Algoma CHP	91	83
Chapleau Co-gen	72	53

5.1.3 Final Planning Forecast

The final net annual peak demand forecast developed for the IRRP is shown in Figure 5.1.3 and was used to carry out system studies that resulted in identifying the region's needs. As shown, the forecasted demand in the ELS Region is expected to remain relatively flat over the study period with a peak of 348 MW in 2031. This forecast includes distribution load plus existing industrial loads; it does not include a high industrial growth or expansion scenario, which will be considered as part of the IESO's bulk planning study in 2021 given the impact to the bulk transmission network in the broader region.

[3] The contribution factors for solar is based on actual summer and winter output from solar DG facilities connected to SSM PUC from 2016 to 2018. These represent the largest distribution connected solar facilities in the region.

Figure 5.1.3 | LDC Net Extreme Weather Forecast

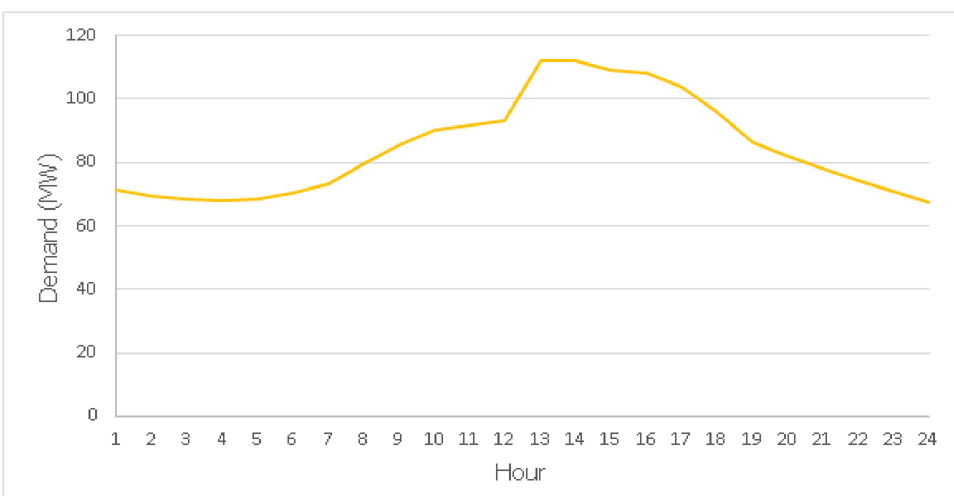


5.2 Load Duration Forecast (Load Profile)

In addition to the planning forecast developed for the purposes of identifying system needs, a load duration forecast was developed to further characterize the needs. Ultimately, the load duration forecast enables evaluation of the suitability of certain solution types to meet the area's magnitude, frequency and duration of needs. Using historical hourly duration information, a sample 8,760-hour profile was created and scaled such that the peak hour would align with the peak demand forecast in a given year of the planning horizon.

A sample of a typical peak-day profile for St. Mary's MTS and Tarentorus MTS is shown in Figure 5.2.

Figure 5.2 | St. Mary's MTS and Tarentorus MTS on January 19, 2040

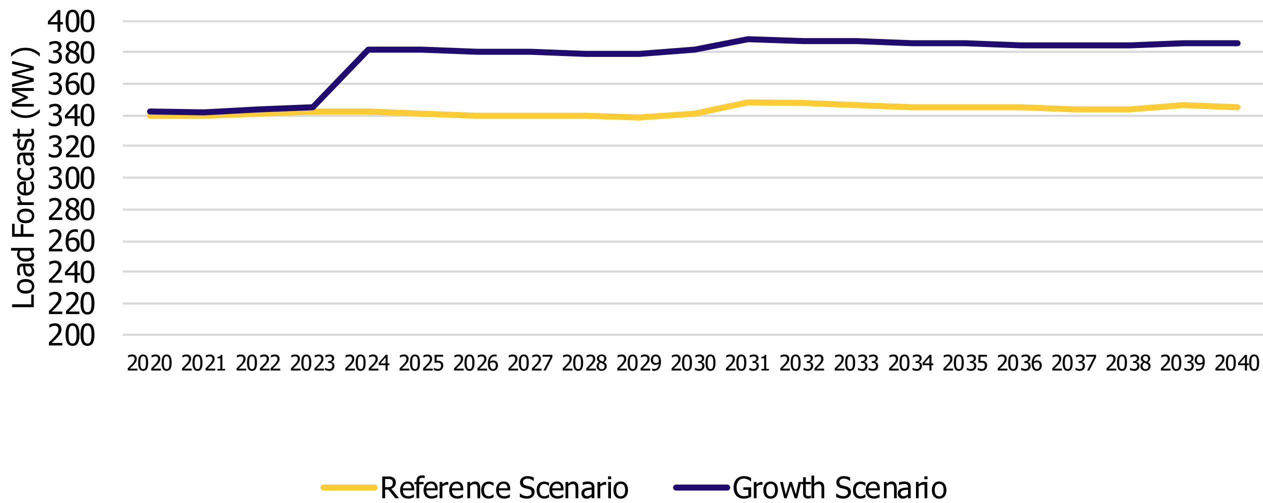


Additional details on the development of the load duration profiles are available in Appendix B.

5.3 Planning Forecast Sensitivity

In addition to the reference planning forecast, some of the LDCs also provided an incremental growth scenario. The reference forecast accounts for annual trend line growth which in the ELS region is fairly flat, when not considering high industrial growth, as seen in Figure 5.3. The incremental growth scenario takes into account large customer expansions and new potential customers that were uncertain at the time of forecast creation, 2% buffer for consideration of electric vehicles, customer expansions and new customers. These scenarios were taken into account in assessing the ELS region's needs and were studied as a sensitivity for the worst-case scenarios identified in the technical studies identified in Appendix D. The sensitivity results did not give rise to any new needs but did exacerbate existing needs in the area. Figure 5.3 shows the comparison between the reference planning demand forecast and the growth scenario. Note that this sensitivity does not capture the high industrial load growth that will be considered in the IESO's bulk planning study.

Figure 5.3 | Comparison Between Reference and Growth Scenario



6. Electricity System Needs

Based on the demand forecast, system assumptions and application of planning criteria, the Technical Working Group identified electricity needs for this region over the current planning period from 2020 to 2040. This section summarizes the needs identified for the ELS region. For practical purposes, not every forecast year is assessed. Year 1 (2020) is assessed to represent the present-day regional power system, Year 5 (2025) is assessed to represent the near-term planning horizon, Year 10 (2030) is assessed to represent the medium-term planning horizon, and Year 20 (2040) is assessed to represent the long-term planning horizon.

These needs are categorized in four groups in accordance with ORTAC and NERC criteria: step-down station capacity, system capacity and performance, load security and load restoration.

6.1 Step-Down Station Capacity Needs

Step-down transformer stations convert high-voltage electricity from the transmission system to lower-voltage electricity for delivery through the distribution system to end-use customers. Each station is capable of converting a certain amount of power on a continuous basis and a slightly higher amount of power for a short duration, typically 10 days, which is referred to as its Limited Time Rating (LTR). Loading a station beyond this amount is not permissible except in emergency conditions, as it lowers the life expectancy of facility equipment and can impact reliability for customers.

Step-down station capacity needs are determined by comparing the non-coincident station peak demand forecast to the facility's 10-day LTR. When a step-down station's capacity is reached, options for addressing the need include reducing peak demand in the supply area (e.g., through EE or DERs), or building new step-down transformer capacity to serve incremental growth.

Table 6.1 shows that there are no transformer capacity limitations for the ELS region in the planning forecast for planning years 2020, 2025, 2030 and 2040.

Table 6.1 | Step-down Station Capacity Needs

Station	Continuous Rating (MVA)	10-day LTR Rating (MVA)	2020 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Andrews TS	5.0	5.0	0.22	0.22	0.22	0.22
Batchawana TS	4.3	4.3	1.64	1.72	1.78	1.92
DA Watson TS	75.0	97.5	8.47	8.76	9.01	9.51
Echo River TS	25.0	25.0	14.05	14.46	14.79	15.61

Station	Continuous Rating (MVA)	10-day LTR Rating (MVA)	2020 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Goulais Bay TS	15.0	15.0	8.46	8.75	8.99	9.47
Limer TS (proposed TS)	TBD	TBD	37.0	54.0	56.0	56.0
MacKay TS	0.5	0.5	0.04	0.04	0.04	0.04
Northern Avenue TS	5.0	5.0	2.48	2.56	2.64	2.78
Chapleau DS	17.05	17.05	6.37	9.62	10.07	11.32
Chapleau MTS	10	10	4.31	4.68	4.37	4.29
St. Mary's+ Tarentorus MTS	210	210	116.11	112.30	111.09	112.21

6.2 System Capacity and Performance Needs

System capacity refers to the amount of power that can be supplied by the regional transmission network, either by bringing power in from other parts of the province, or by generating it locally.

System capacity in the ELS region was assessed by modelling power flows throughout the local grid under anticipated non-coincident peak demand conditions, and applying a series of standard contingencies (outage events) as prescribed by ORTAC and NERC. Co-incident peak demand was assumed for St. Mary's and Tarentorus TS because PUC Distribution Inc. is able to transfer loads between the two stations during peak demands to avoid overloading any of the transformers. Performance standards and criteria dictate how well the system must be able to operate following these contingencies. Standards at risk of not being met are identified as a system need. System performance before or following a disturbance must meet criteria identified in ORTAC section 4 and NERC standard TPL-001.

As with station capacity needs, system capacity needs can be addressed by upgrading the system to increase LMC, or addressed/deferred by reducing peak demand. Details on identified system capacity needs are described in the following sections.

6.2.1 Third Line Autotransformer Approaching Capacity

Third Line TS is a key supply point in the ELS region and consists of two 230/115 kV, 150/200/250 MVA autotransformers. The Third Line TS 230 kV station yard is supplied by circuits K24G extending to Mackay TS and P21G/P22G extending east to Mississagi TS. The Third line TS 115 kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, Sault No.3 circuit and Northern Avenue Line circuit. It also supplies the loads at St. Mary's and Tarentorus stations via 115 kV circuits GL1SM GL2SM, GL1TA, and GL2TA.

When one of the Third Line autotransformers is lost, the loading of the companion autotransformer approaches its 10-day LTR today. This was also identified in the Needs Assessment and the Scoping

Assessment. The loading on the companion transformer would be reduced modestly beyond 2023 when the Sault No.3 circuit returns to a network (non-radial) configuration. Sault No.3 is a 115 kV transmission circuit that runs from MacKay TS 115 kV station yard to Third Line TS 115 kV station yard. This circuit is currently de-rated due to deteriorating condition of the overhead conductor and operated normally-open at the Mackay TS terminal. Hydro One is currently planning to refurbish the circuit like-for-like as part of its planned sustainment activities to restore it to non-radial operation. The refurbished circuit is expected to be in-service by 2023.

This is not a firm need as there is no existing violations but this is flagged because loading on Third Line autotransformers is close to its LTR rating and should continue to be monitored. As mentioned in the Need Assessment, one of the Third Line autotransformers is scheduled to be replaced by 2025. However, the replacement autotransformer would not add any significant supply capacity to this region due to the ratings of a standard 230/115 kV autotransformer.

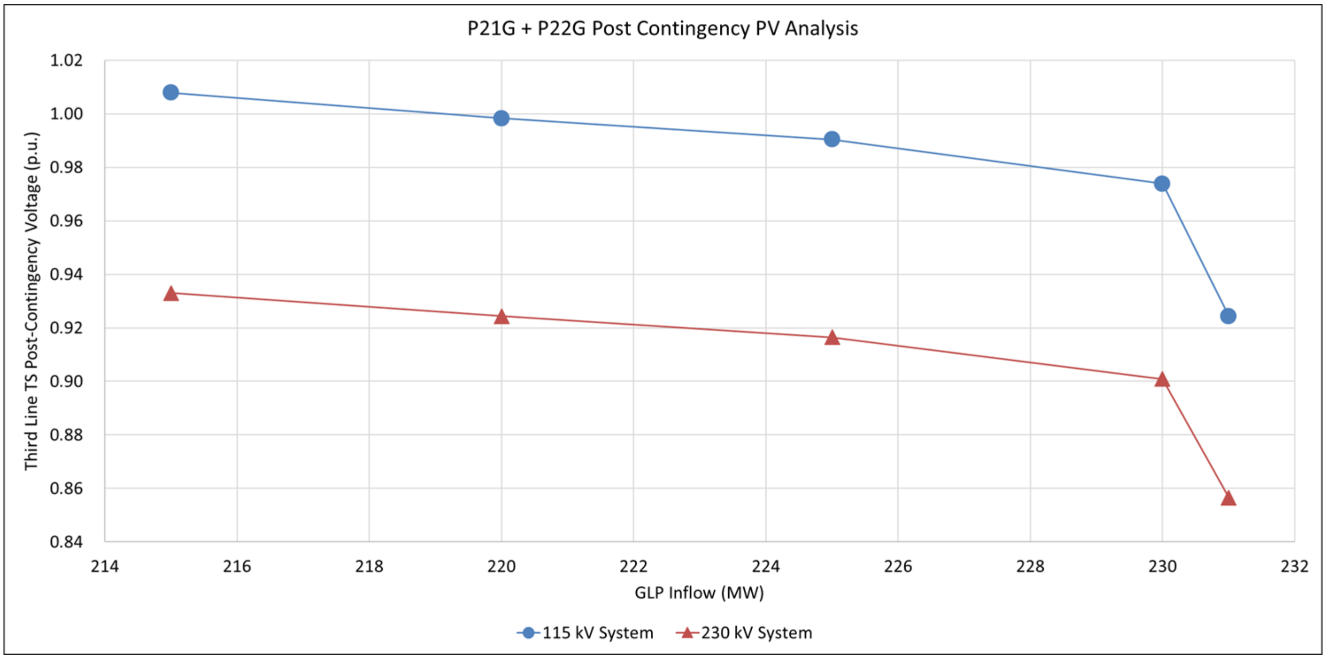
6.2.2 Voltage Concern Following the Loss of P21G/P22G

P21G and P22G are 230 kV circuits running from Third Line TS to Mississagi TS. These circuits form a critical supply path to the ELS region. A double circuit loss of P21G and P22G would cause voltage drop in excess of 10% (voltage collapse) at Third Line TS and other ELS stations throughout the planning period. This loss can be caused by an outage to the first circuit, followed by a contingency to the second or by a simultaneous loss of both circuits due to a contingency involving adjacent circuits on a common tower. Loss of P21G and P22G takes Third Line autotransformer T1 out of service by configuration. The voltage instability point is reached when GLP Inflow exceeds 230 MW and the circuits are out of service. [4] This is an existing issue today.

Third Line TS is equipped with Instantaneous Load Rejection Scheme with six load blocks to select for load shedding. Currently there is no provision in this scheme to allow remote arming of load rejection for the P21G+P22G double contingency. The IESO has to manually request Hydro One Sault Ste. Marie to arm certain amounts of load for rejection, and Hydro One Sault Ste. Marie prioritizes selection of the load blocks. The existing scheme has a provision to remotely arm load for this contingency, which would remove the need to initiate the manual procedure and hence, make the arming procedure more efficient.

[4] GLP Inflow is a system interface defined by the MW flow west at Mississagi TS on P21G and P22G circuits plus MW flow into Third Line TS on K24G circuit.

Figure 6.2.2 | P21G + P22G Post Contingency PV Analysis



6.2.3 Capacity Overload of 115 kV Circuit No. 1 Algoma

A failure of breaker (BKF) 214 to operate at Patrick St TS will cause the loss of No. 2 Algoma and No. 3 Algoma circuits from Third Line TS to Patrick St TS. This results in thermal overload of the remaining No. 1 Algoma circuit beyond its short-term emergency (STE) rating during peak loads at Patrick St TS; note that No. 1 Algoma is the lowest rated circuit out of the three. This thermal overload of No. 1 Algoma can also occur with one of the Algoma circuits initially out of service, followed by the loss of another Algoma circuit.

This is an existing issue and thus an immediate need which was also identified in the Needs Assessment and Scoping Assessment. This is currently mitigated by the Patrick St TS manual load shedding scheme under which load is curtailed manually at Patrick St TS following the loss of one of the Algoma line circuits. This is done to prevent overloading of the No. 1 Algoma circuit in case the second circuit is also lost. Since this scheme is manual, load has to be shed before the actual contingency of the second circuit has taken place which is an event that may not occur. This scheme was designed as an interim solution until a more permanent solution was implemented.

6.2.4 Capacity Overload of 115 kV Circuit Sault No.3

During an outage to either the P25W or P26W circuit between Wawa TS to Mississagi TS, a contingency on the K24G circuit between Third Line TS and Mackay TS results in the thermal overload of the Sault No.3 circuit beyond its STE ratings starting in 2023 when Sault No.3 circuit is connected in a network configuration.[5] This phenomenon is a result of high East West Transfer (EWT) flows and losing two circuits that carry that flow.[6]

In addition, when one of the Third Line TS autotransformers is out of service, a normally operated Sault No.3 circuit (after its proposed upgrades) helps to alleviate overloading of the companion Third

[5] Sault No.3 circuit is being refurbished as part of a sustainment project

[6] EWT is defined as the MW flow at Wawa TS on circuits W21M and W22M.

Line TS autotransformer. However, if the second autotransformer is also lost, Sault No.3 circuit will be overloaded beyond its STE rating and causes a significant voltage decline in the 115kV area served by Third Line TS.

6.2.5 Anjigami T1/Hollingsworth T1 and T2 overload

Anjigami TS is connected to Wawa TS, Magpie TS, D. A. Watson and Hollingsworth TS. For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa based on the latest load forecast submitted by the LDC. This is consistent with 2014 Needs Assessment report finding that identified overloading on Hollingsworth TS – Transformer T2 / Anjigami TS – Transformer T1 due to load increases on the 44 kV system. HOSSM is working with the impacted LDC and proposed a solution of building a new 115/44 kV station, with a proposed named Limer TS (subject to change) that will tap off Hollingsworth 115 kV circuit to handle the load increase.

6.2.6 Bulk Area Needs

There is a potential for significant growth in industrial load in the ELS region over the planning period which would have a material impact on the bulk transmission system in the broader region. This growth will be considered as part of the IESO's bulk planning study which will commence in 2021.

Based on the reference load forecast included in this IRRP, the following bulk system need was identified and will be further considered as part of the bulk planning study described above. Following the loss of one of the 230 KV circuits, P25W or P26W circuits from Mississagi TS to Wawa TS, the companion circuit becomes loaded beyond its LTR rating under high westward power flow on the EWT.

6.3 Load Security Needs

The load security criteria in ORTAC Section 7.1 describes the maximum amount of load that can be interrupted following specified contingencies. A summary of the load security criteria can be found in Table 6.3. The load security criteria are met in the planning timeframe for the ELS region.

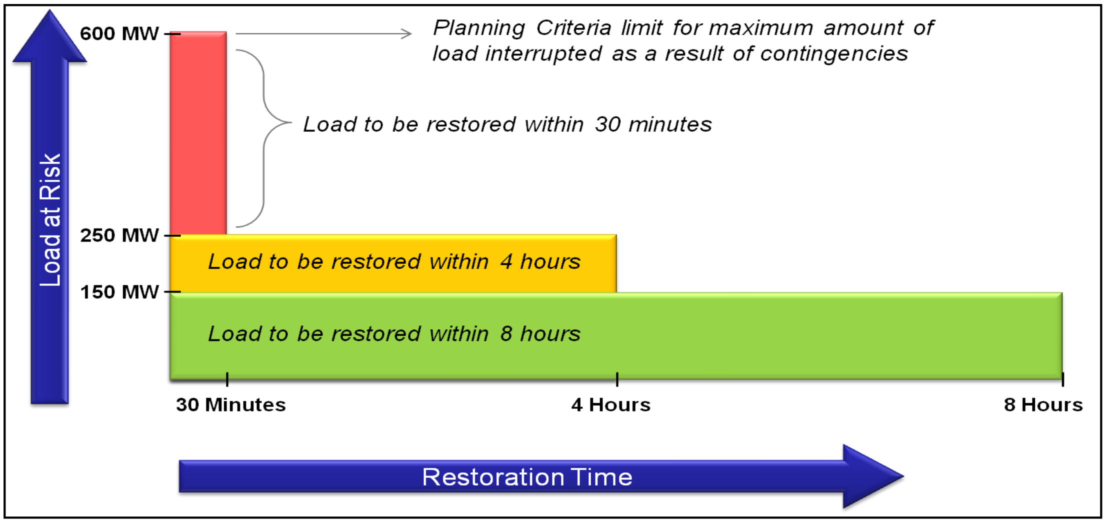
Table 6.3 | Load Security Criteria

Number of Transmission elements o/s	Local Generation Outage	Amount of load allowed to be interrupted by configuration	Amount of load allowed to be interrupted by load rejection or curtailment	Total amount of load allowed to be interrupted
One	No	≤ 150 MW	None	≤ 150 MW
One	Yes	≤ 150 MW	≤ 150 MW	≤ 150 MW
Two	No	≤ 600 MW	≤ 150 MW	≤ 600 MW
Two	Yes	≤ 600 MW	≤ 600 MW	≤ 600 MW

6.4 Load Restoration Needs

As described in Section 7.2 of ORTAC, load restoration criteria specify the maximum amount of time it can take to restore interrupted load. A visual representation of ORTAC's load restoration criteria is shown in Figure 6.4.

Figure 6.4 | Load Restoration Criteria



6.5 Summary of Identified Needs

Table 6.5 below summarizes the electric power system needs identified in the ELS region in this IRRP. All of the needs exist today or arise in the near term. Note that the Anjigami T1/Hollingsworth T1 and T2 overload is customer driven. Section 7 considers different options to meet these needs and ultimately makes recommendations on how to address them.

Table 6.5 | Summary of Needs in the ELS Region

Need	Need Date
Loss of one Third Line TS autotransformer causes the companion transformer to be loaded close to its capacity	This is not a need, but flagged for ongoing monitoring
Loss of P21G and P22G circuits causes voltage collapse at Third Line TS. Enabling remote arming of GLP Instantaneous Load Rejection Scheme will drive operational efficiencies	Immediate
Loss of two Algoma circuits or a Patrick St TS 214 BKF results in thermal overload of the remaining Algoma circuit	Immediate
During an outage of P25W or P26W circuits, a loss of the K24G circuit results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	2023

Need	Need Date
During an outage of one of the Third Line TS autotransformers, a loss of the companion autotransformer results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	2023
For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa	2024

7. Plan Options and Recommendations

This section describes and evaluates the options considered to address system needs in the ELS region. This includes an evaluation of each option and the recommendations for action.

7.1 Alternatives for Meeting Needs

This section outlines the options considered to address the needs identified in the ELS Region, including how these options were evaluated and the recommendations for action in the near term.

There are generally two types of approaches for addressing electricity needs in regional areas:

- Target measures to reduce peak demand to maintain loading within the system's existing limits largely through the use of EE, and other demand management strategies.
- Build new infrastructure to increase the LMC of the area.

DERs, including DR, EE measures, or energy storage are all well suited to the first approach.

Even if not being pursued to address specific system capacity needs, there are other potential benefits to non-wires investments, such as customer cost savings, and reducing GHG emissions. Some of these other objectives have been identified in the City of Sault Ste. Marie's Greenhouse Gas Emissions Reduction Plan.

Where reducing peak demand is not technically or economically feasible through the use of DERs, the other strategy is to upgrade the infrastructure to increase the LMC of the area. In cases where a step-down station exceeds its maximum capacity, the station can be expanded. If the transmission system is at its capacity, generally the options are to build new local generation (to reduce the amount of power that needs to be brought in from elsewhere), or build new or upgrade the existing transmission infrastructure to increase transfer capability. New remedial action schemes can also be introduced when transmission upgrades are not considered feasible at this time. These schemes can act to reduce load and/or generation to meet identified transmission system needs.

Each of these categories of options are further explored below as they relate to the needs in the ELS region.

7.1.1 Conservation

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. Conservation is achieved through a mix of program-related activities including behavioural changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

On September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework. As discussed in Section 5.1.1., although the information about the new CDM Framework was not available when the forecast was being developed, continued program-driven CDM savings were included in the forecast consistent with the levels of the previous Interim Framework. The difference between these levels of expected savings is marginal. The new CDM Framework will contribute to lowering the net demand as seen on the transmission system; however, estimations of the savings in the area show that the identified needs still exist after these savings are accounted for.

Conservation expected to be achieved through time-of-use and codes and standards has already been included in the planning forecast scenarios.

While there is the potential for additional savings from CDM activities, beyond the levels assumed in the load forecast, these options were not investigated further at this time because the size of the need represents more than 66% of the winter peak demand of the ELS area. CDM programs tend to be more feasible and cost effective when the need represents much small percentage of the total system load (e.g., 2%).

For this reason, additional CDM activities were not considered further to address the immediate needs identified.

7.1.2 Local Generation

Local generation options were also considered to address the identified needs. A local generator, sited in the 115 kV system, could technically meet the reliability needs of the ELS region including the thermal overload of 115 kV circuit Sault No.3 and prevent arming of load for PxG contingency. The facility would need to be sized to deliver approximately 65 MW of winter peak capacity, when considering approximately 11 MW contribution from existing demand response in the region. In addition, the generation solution would have to address the annual energy requirements seen in Table 7.1.2 below. Based on these need characteristics, the NPV of a new combined cycle gas turbine (CCGT) generator was evaluated and estimated at $250 million, which includes capital costs, operating costs and credit for system capacity value to the broader system (as dictated by provincial needs and zonal capacity limitations). Based on economic analysis of available technology, the CCGT generator option is the cheapest utility scale non-transmission alternative. Given the cost of this option compared to those of the transmission options, this alternative was ruled out.

Table 7.1.2 | Energy Required to Address Reliability Needs at Third Line TS

	2020	2025	2030	2035	2040
Annual Energy Need (MWh)	224,000	196,000	168,000	153,000	122,000

7.1.3 Transmission

A number of transmission and distribution, or "wires," solutions were considered by the Technical Working Group to meet the near-term needs. "Wires" infrastructure solutions can refer to new or upgraded transmission or distribution system assets, including circuits, stations, or related equipment, and remedial action schemes.

The following remedial action schemes were considered by the Working Group to meet the system capacity and performance needs in the near term.

Enable Remote Arming for P21G+P22G in GLP Instantaneous Load Rejection Scheme

There is an existing RAS called the GLP Instantaneous Load Rejection Scheme that is initiated for the loss of both Third Line autotransformers or the loss of both P21G and P22G circuits. At present, a request has to be made to Hydro One Control Room to enable the scheme for the loss of P21G and P22G double contingency. It is a manual process where IESO Control Room has to call Hydro One Control Room and Hydro One arms the load. This scheme has a setting, which once enabled will allow IESO Control Room to arm load remotely, thus eliminating the need for the manual arming sequence and making the load rejection arming procedure more efficient. It would cost the transmitter approximately $50,000 to enable the remote arming setting in the RAS. Part of the change will require relevant Facility Description Document (FDD) and IESO System Control Order (SCO) documentation to be updated.

Automate Patrick St TS Manual Load Shedding Scheme

There is an existing Patrick St TS Manual load shedding scheme designed to manage the load at Patrick St TS. Loads at Patrick St TS are normally supplied by the three 115 kV Algoma circuits and from Clergue GS and load displacement generators at Algoma Steel Inc. Following contingencies that leave only one Algoma circuit in service, manual load shedding may be required. Since this process is not instantaneous, it also exposes the remaining Algoma circuit to an extremely high flow if the second circuit was to trip during the manual load shedding sequence. This scheme was originally designed as an interim solution until a more permanent solution was employed.

ORTAC provisions allow for planned load rejection up to 150 MW for any two elements out of service; however, a load shedding scheme would need to be automatic and allow load rejection of Patrick St TS load upon the loss of an Algoma circuit when another Algoma circuit is out of service. This solution would cost approximately $2 Million. This scheme can be expanded to arm load for the Patrick St TS 214 BKF.

Control Actions and System Reconfiguration for Overloading of Sault No.3

An operational control action such as opening Sault No.3 circuit between Sault Ste. Marie and the Mackay sub-system could be implemented when there is an outage to one of the 230 kV circuits P25W or P26W to avoid post-contingency overloading on the 115 kV Sault No.3 circuit. This would address the need on the Sault No.3 circuit but would also overload the companion 230 kV PxW circuit during high flows on the East West Tie.

During an outage to one of the Third Line TS autotransformers, Sault No.3 can become overloaded if the remaining autotransformer is also lost due to a contingency. The loads served by Third Line TS will also suffer a voltage decline beyond that permissible via ORTAC. To prevent these phenomena, one solution is to reject load; however, studies show that during peak demand conditions, more than 150 MW of load shedding may be required which violates ORTAC. Another potential solution is to reconfigure the system following the loss of the second transformer during peak conditions, however, this could similarly result in significant amounts of load lost by configuration.

Given that these needs involve facilities that will be considered in the IESO's 2021 bulk plan, they will be provided as input into the bulk planning study and the solutions to address them will be coordinated with the outcomes of the bulk planning study.

7.2 Recommended Plan to Address Local Needs

To meet identified electricity needs in the ELS region, the Technical Working Group recommends the implementation of the following actions:

Monitor Demand Growth and Supply in the Region

The Technical Working Group recommends closely monitoring demand growth and supply in the ELS region to determine if and when additional transformation capacity at Third Line TS is required. This includes monitoring the city of Sault Ste. Marie's climate plans, described further below, as they may have an effect on the demand.

The city of Sault Ste. Marie is planning on increasing community and corporate climate change initiatives through their community Green Gas Emissions Reduction Plan.[7] This plan sets out the actions required on a short, medium and long-term basis in order to reduce GHG emissions in the city of Sault Ste. Marie. The goal is for the city of Sault Ste. Marie to reduce their GHG emissions and be net zero by 2050. Actions have been broken down by sector which includes Buildings & Energy at a community level. The GHG reduction plan in the Buildings & Energy sector includes:

- Increase uptake in residential and commercial energy efficiency retrofits that reduce the use of fossil fuels;
- Increase the number of new homes and business builds to incorporate energy efficient equipment (e.g., new furnaces, weather stripping, efficient lighting, etc.);
- Research policies for efficient new builds that go above the Ontario Building Code;
- Develop a community energy efficiency retrofit program (either for energy efficiency retrofits or renewable energy); and
- Encourage the use of energy reduction devices such as thermal imaging heat devices.

These activities also have the potential to reduce electricity demand in the city of Sault Ste. Marie and are therefore important considerations as part of regional planning. The Working Group will continue to monitor implementation of these recommendations and their impact on the demand.

The Technical Working Group encourages potential new customers in the ELS Region to notify the IESO, HOSSM and their appropriate LDC of their growth or connection plans as soon as possible such that this growth can be reflected in ongoing planning in the region. If required, the next round of regional planning can be initiated early, i.e., before 5 years, should the demand follow the alternate growth scenario as described in section 5. The IESO will also continue to monitor potential non wires alternatives and implementation options.

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[7] https://saultstemarie.ca/City-Services/City-Departments/Community-Development-and-Enterprise-Services/FutureSSM/Greenhouse-Gas-Emissions-Reduction-Plan.aspx?fbclid=IwAR1JDdn5-ZwoXP4uIZnu3C9Y-lOS3IFJnBmXqlY1DWdyQiAVQHj4bgF3R6c

The overall demand forecast for the ELS region is relatively flat over the planning period but has potential for significant growth resulting from large industrial load projects and expansions. This will be studied as part of an IESO bulk planning study.

Enable Remote Arming for P21G+P22G in GLP Instantaneous Load Rejection Scheme

The Technical Working Group recommends that HOSSM modify the existing GLP Instantaneous Load Rejection Scheme as soon as practical. This scheme would allow remote arming of load rejection, within amounts permissible via ORTAC, during periods of high demand in case the transmission circuits supplying Sault Ste. Marie (P21G and P22G) are both out of service, and would result in operational efficiencies over manual arming. The likelihood of rejecting the load as a result of both transmission circuits being out of service is low but must be planned for as per planning standards. The approximate cost of expanding this scheme is $50K.

Implement Automatic Load Rejection Scheme at Patrick St TS

The Working Group recommends HOSSM to implement a new automatic load rejection scheme to arm up to 75 MW of load rejection automatically during periods of high demand in case the companion circuits to No. 1 Algoma circuit are both out of service. This would solve the thermal issues to the electricity supply within Sault Ste. Marie at an approximate cost of $2 Million.

Coordinate with IESO's Bulk Planning Study Regarding Sault No.3 Circuit Overloading

Given that the facilities driving the needs related to the overloading of the Sault No.3 circuit will be considered in the IESO's 2021 bulk plan, it is recommended that these needs be carried forward as an input to the bulk plan so as to ensure a coordinated approach with respect to the outcomes and solutions developed as part of the bulk plan.

New 115/44 kV Station

The Technical Working Group has been informed that HOSSM plans on building a new 115/44 kV station that will tap off the Hollingsworth 115 kV circuit and will serve the incremental customer driven load. This is in line with the recommendation made in the Needs Assessment; HOSSM will work with the local LDC and customers when sizing and designing the new station.

7.3 Implementation of Recommended Plan

To ensure the electricity needs of the ELS area are addressed, it is important that the recommendations are implemented in a timely manner. The specific actions and deliverables associated with the plan are outlined in Table 7.3 below, along with their recommended timing and the parties with lead responsibility for implementation. The ELS Working Group will continue to meet regularly during the implementation phase of this IRRP to monitor developments in the ELS region and to track progress of these deliverables.

Table 7.3 | Implementation of Recommended Plan for ELS Region

Need	Recommendation	Lead Responsibility	Required By
Loss of one Third Line TS autotransformer causes the companion autotransformer to be loaded close to its capacity	Monitor load and supply in the ELS region	IESO/HOSSM	Immediately and Ongoing
Loss of P21G and P22G circuits causes voltage collapse at Third Line TS and other ELS stations	Enable remote arming of GLP Instantaneous Load Rejection Scheme for P21G and P22G double contingency for operational efficiency over manual arming	Hydro One	Immediately
Loss of two Algoma circuits or a Patrick St TS 214 BKF results in thermal overload of the remaining Algoma circuit	Implement automatic load rejection scheme at Patrick St TS	HOSSM	Immediately
During an outage of P25W or P26W circuits, a loss of the K24G circuit results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
During an outage of one of the Third Line TS autotransformers, a loss of the companion autotransformer results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023

For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa	Hydro One to work with the LDC to build a new 115/44 kV station that will tap off Hollingsworth 115 kV circuit to accommodate the load increase	HOSSM	2024

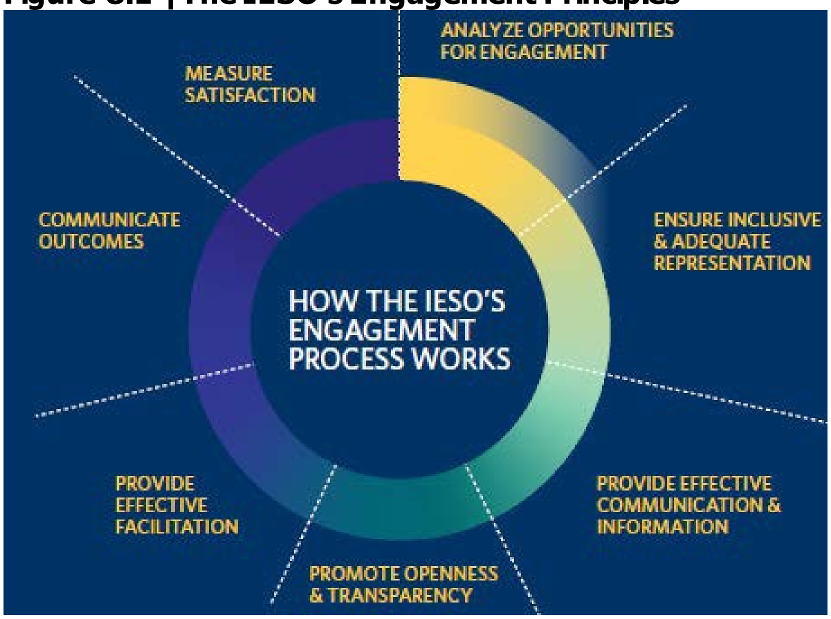
8. Engagement

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 East Lake Superior 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. [8] 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 ELS

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 and are adequately informed about the background and issues in order to provide meaningful input on the development of the long-term electricity plan for the region.

[8] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

Creating the engagement plan for this IRRP involved: [9]

- 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
- 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[10]
- A dedicated section on the IESO's online engagement platform, IESO Connects, to provide an alternative mechanism for communities and interested parties to learn about the IRRP and offer any input[11]
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin
- Public webinars
- Face-to-face meetings
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (See section 1.4 Outreach with Municipalities)

8.3 Engage Early and Often

Preliminary discussions were held early in the planning process to gain an understanding of key local energy priorities and help inform the engagement approach for this planning cycle. These discussions were important to establish and build new relationships as this round of planning marked the first cycle requiring regional coordination and community engagement.

Formal engagement began with an invitation to targeted communities and those with an identified interest in regional issues to learn about and provide comments on the ELS Scoping Assessment Report before it was finalized. Following a public webinar and written comment period, the final Scoping Assessment was published in October 2019 with responses to feedback received, which identified the need for an IRRP for the ELS region.

Outreach then began with targeted communities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to subscribers of the ELS region to ensure that all interested parties were made aware of this opportunity for input.

[9] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/els/East-Lake-Superior-IRRP-Engagement-Plan-20200514.ashx

[10] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-East-Lake-Superior

[11] https://iesoconnects.ca/content/electricity-planning-east-lake-superior

Three 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 cross-representation of stakeholders and community representatives attending the webinar and submitting written feedback during a 15-day comment period.

The first webinar sought input on the draft engagement plan, the electricity demand forecast and needs. Comments received during the webinar were related to the underlying numbers, factors and assumptions in the demand forecast. As a result of this feedback, further clarification was provided in subsequent engagement events and materials.

The second webinar sought feedback on the defined electricity needs for the region and potential options. Comments received during the written feedback window touched on the following major themes that has been considered in the development of this IRRP:

- Options development, specifically the consideration on non-wires alternatives (NWAs)
- Consideration of high industrial growth potential
- Access to data and information to enable the market to respond to regional electricity needs

As a final step in the engagement initiative, the third public webinar was held to seek input on the analysis of options and draft IRRP recommendations. Comments were received around the potential for non-wires options, particularly energy storage, to meet regional electricity needs and clarification on the economic assessment of options. Non-wires options including generation and CDM were considered in the analysis of potential solutions, and as discussed during the third webinar, no specific actions are required at this time. The uptake of non-wires resources will be monitored as part of ongoing monitoring and planning for the ELS region.

Based on the discussions both through the ELS IRRP engagement initiative and the IESO's Regional Electricity Networks, it is clear that there is broad interest to further discuss the potential for alternative energy solutions in supporting future growth. [12] Ongoing discussions will continue through the IESO's Northeast Regional Electricity Network to keep communities and interested parties engaged on local developments, priorities and planning initiatives in preparation for the next planning cycle. [13]

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's ELS IRRP engagement web page.

8.4 Bringing Communities to the Table

The IESO held meetings with the City of Sault Ste. Marie, large industrial customers and energy service providers in the region to seek input on major planning and development projects and to ensure that local initiatives were taken into consideration in the development of this IRRP. These meetings helped to inform the region's electricity needs and provided opportunities to strengthen these relationships for ongoing dialogue beyond this IRRP process.

[12] https://ieso.ca/en/Get-Involved/Regional-Planning/Electricity-Networks/Overview

[13] https://iesoconnects.ca/collections/northeast-regional-electricity-network

9. Conclusion

The ELS IRRP identifies electricity needs in the region over the 20-year period from 2020 to 2040, recommends a plan to address immediate and near-term needs, and identifies needs that are related to the bulk transmission system in the broader region that should be further considered as part of the IESO's bulk planning study for the region, commencing in 2021, to ensure a coordinated approach with respect to outcomes.

Specifically, the IRRP includes recommendations to monitor load growth and supply in the region, and implement remedial action schemes to ensure the reliability of the system supply within the region. The IRRP also recommends that the needs identified with respect to the overloading of the Sault No.3 circuit be considered as part of the IESO's bulk planning studies for the area in 2021 given that these facilities will also be considered in the bulk study.

Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the regional planning for the ELS region.

The Technical 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.

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Powering Tomorrow.

East Lake Superior Region Integrated Regional Resource Plan

Appendices

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Appendix A. Overview of the Regional Planning Process

A.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 Ontario Energy Board (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. [1] 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.

[1] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

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 Regional Infrastructure Plan ("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.

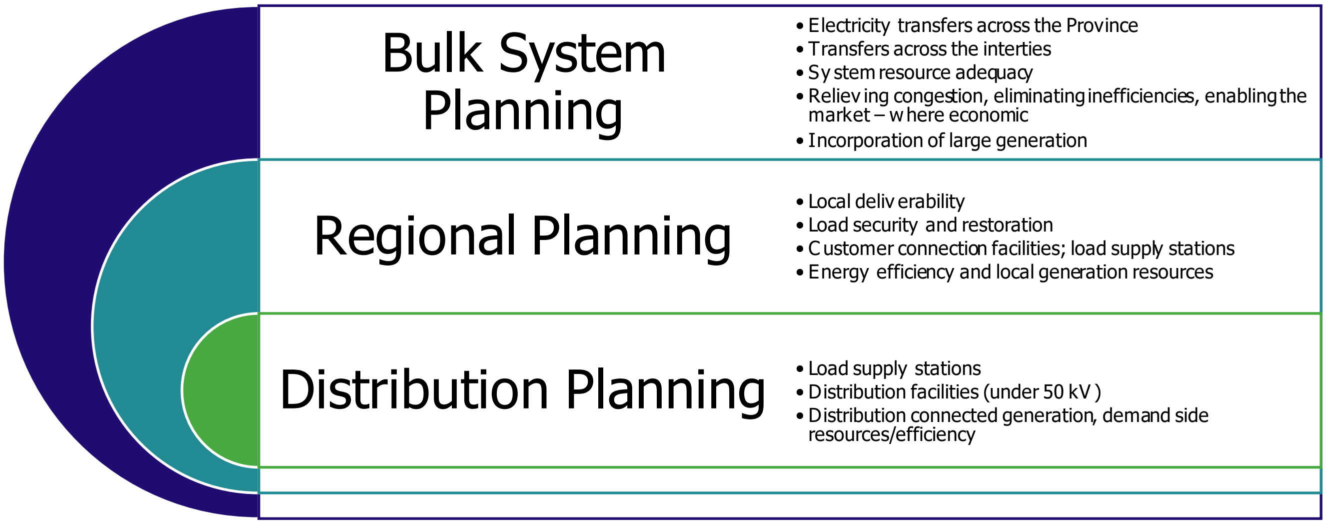
The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are posted on the IESO's and the relevant transmitter's web sites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. 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 A.1, three levels of electricity system planning are carried out in Ontario:

- Bulk system planning
- Regional system planning
- 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. Distribution planning, which is carried out by local distribution companies ("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.

Figure A.1 | Levels of Electricity System 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.

Appendix B. Demand Forecast

This Appendix describes the methodologies used to develop the demand forecast (peak and duration) for the East Lake Superior (ELS) Region IRRP studies. Forward-looking estimates of electricity demand were provided by each of the participanting LDCs and informed by the forecast base year and starting point provided by the IESO. The sections that follow describe the method used by the IESO to determine the forecast starting point, the approaches and methods used by each LDC to forecast demand in their respective service area, the conservation and DG assumptions and the duration forecast methodology.

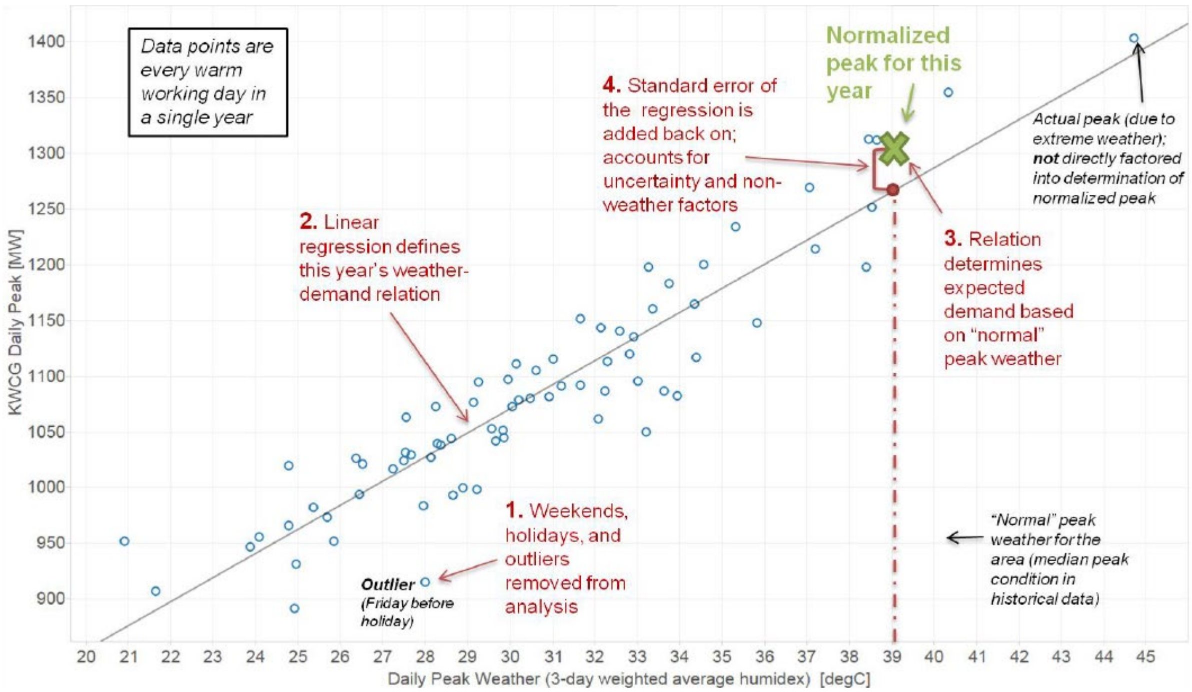
B.1 Method for Determining Forecast Starting Point

To develop a standardized starting point for the ELS region demand forecast, the following steps were performed:

- 5-year i.e., 2014-2018, historical non-coincident peak demand data was gathered for each station.
- Historical demand data was weather normalized to reflect median peak weather conditions at each station
- Historical output from Distributed Generation at the time of peak was added back to the historical demand for each year (because DG output is subtracted from the gross forecast).
- The starting point is typically selected using the most recent weather-corrected gross peak load; previous year's data points are used to observe trends and outliers.

In order to weather-normalize the data, historical demand was adjusted to reflect the median peak weather conditions for each transformer station in the area for all historical years. Median peak refers to the expected peak demand under the most likely, or 50th percentile, weather conditions. This means that in any given year there is an estimated 50% chance that the actual peak demand will exceed this peak, and a 50% chance that the actual peak demand will be lower than this peak. The methodological steps are described in Figure B-1; note that this is an illustrative example that was developed for a different region.

Figure B.1 | Method for Determining The Weather-Normalized Peak



The impact of Distributed Generation was then added to the median weather peak for all historical years and the most recent year (2018) was used as a starting point, for each LDC station. This data was provided to the LDCs to inform the starting point of their 20-year demand forecasts, which were developed using the their preferred methodology (described in Appendix B.2, below).

Once the LDC 20-year, median peak demand forecasts were provided to the IESO, the forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. The studies used to assess the reliability of the electric power system generally require the use of extreme weather demand forecasts, or, expected demand under the coldest weather conditions (in the case of ELS, which is a winter peaking region) that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g., winter polar vortexes) are generally when the electricity system infrastructure is most stressed. The extreme weather adjustment factors used in the ELS IRRP were calculated as per IESO's methodology for modelling extreme weather conditions, which determines the relationship between weather and demand for a given region in a given timeframe.

B.2 LDC Forecast Methodologies

This section describes the methodologies used by the participating LDCs to develop their planning forecasts. These include:

- PUC Distribution Inc.
- Algoma Power Inc.
- Hydro One Networks Distribution

B.2.1 PUC Distribution Inc.

For its load forecast, PUC Distribution Inc. utilizes a regression analysis methodology that was approved by the OEB in its 2013 Cost of Service application and is used by multiple LDCs across the Province. PUC Distribution's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized forecast is developed based on a regression analysis that incorporates variables that impact PUC Distribution usage. Second, the weather normalized forecast is adjusted by a historical loss factor to produce a weather normalized billed forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast. The forecast of customers by rate class is determined using a geometric mean analysis and judgment of PUC Distribution. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to the class energy forecast based on the historical relationship between kW and kWh. For further details, please refer to PUC Distribution's OEB IRM application EB-2017-0071 Exhibit 3.

Furthermore, PUC Distribution Inc. considers other supplemental factors derived through its routine planning processes as described in its Distribution System Plan, also filed with the OEB as part of its Cost of Service application. These include potential impacts to the load forecast determined through stakeholder consultations:

- Customer Engagement (residential surveys, large C&I plans, developers, DG and REG customers)
- Municipal Government Consultations (City budgets, official plans, economic development plans, population projections)

For the load forecast period considered in this regional planning report, these additional supplemental factors did not contribute materially to the forecast determined through the regression methodology.

B.2.2 Algoma Power Inc.

Algoma Power Inc. ("API") provides electricity distribution services in the remote areas of Northern Ontario located north and east of the City of Sault Ste. Marie. API serves approximately 12,000 customers on a distribution system consisting of 1,861 kilometers of distribution line. The distribution system extends 93 Km east and approximately 255 Km north of the City of Sault Ste. Marie.

API distributes electricity to widely dispersed residential, seasonal, commercial and industrial customers as well as remote First Nations communities. Organized townships are governed by 14 separate municipal governments and the seven First Nation reserve locations are governed by four First Nations. Apart from property owned by businesses or individuals, API's territory also consists of significant parcels owned by large resource-based companies or provincial parks.

API experiences its peak demand mostly within the winter months due to lack of natural gas heating, a high penetration of electric heating, and a relatively low penetration of central air conditioning in much of its service area. Variances in seasonal peaks are attributable to the varying weather conditions experienced in Northern Ontario.

API follows a trend load forecasting methodology, where future loads are extrapolated based on recent and past peak loads for each connected supply point. A baseline forecast is developed with consideration to normal operating conditions, coincident peak loading and extreme weather conditions. From the established baseline year, a predefined growth rate is applied, which typically accounts for average annual load growth increase, but also factors in known future municipal and industrial developments. Consideration is also given to market trends in potential electricity needs, such as the anticipated deployment of electric vehicles.

B.2.3 Hydro One Networks Distribution

Hydro One Distribution services the areas in East Lake Superior region that are not served by other LDCs through Chapleau DS. Hydro One Distribution used both the econometric and end-use forecasting to develop the 20-year forecast provided to IESO.

A baseline forecast (MW station peak in the the base year) was developed, taking into account such factors as normal operating conditions, coincident peak loading, and extreme weather conditions.

For the ELS IRRP Forecast, Hydro One Distribution used the weather corrected peak demand levels for Chapleau DS.

From the established baseline year, a growth rate (%) was applied to station demand level to provide forecast values for Chapleau DS within the study timeframe.

Assumptions included in the growth rate can be related to such factors as: Ontario GDP growth rate, housing statistics, the intensification of urban developments (i.e., MW/sq.ft); and the need for large scale electrification projects.

Detailed information about load growth, based on local knowledge and relation between local and provincial load was used to augment the forecast values within the study period.

B.3 Conservation Assumptions in ELS Forecast

Conservation measures can reduce the electricity demand and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and CDM Programs. The assumptions used for the ELS IRRP forecast take into account the conservation programs from the provincial Interim Framework. 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 the provincial level, to the Northeast transmission zone and then allocated to ELS region. This section describes the process and methodology used to estimate conservation savings for the ELS Region and provides more detail on how the savings for the two categories were developed.

B.3.1 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 were estimated for the Northeast zone and compared with the gross peak demand forecast in the zone.

From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each TS in the region.

Consistent with the gross demand forecast, 2018 is determined as the base year. New peak demand savings from codes and standards were estimated. The residential annual peak reduction percentages of each year were applied to the forecast residential demand at each TS 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 4.0% peak demand savings through standards. The same is done for the commercial sector, which will see about 0.3% 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.

B.3.2 Estimate Savings from Conservation Programs

In addition to codes and standards, the delivery of CDM programs reduces electricity demand. The impact of existing and committed CDM programs were analyzed, which take into account both policy-driven and funded CDM. These include the Conservation First Framework wind-down and the Interim Framework. While the new 2021-2024 Conservation and Demand Management (CDM) framework was not taken into account (as it was not in place at the time of forecast development), sensitivities were conducted to assess its impact as described in Section 5.1.1 of the IRRP. A top down approach was used to estimate the peak demand reduction due to the delivery of 2019 and 2020 programs, from provincial to Northeast to the TSs 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 building codes and equipment 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 Northeast transmission zone. They were then applied to sectoral gross peak forecast of each TS in the region. By 2020, the residential sector in the region is expected to see about 0.2% peak demand savings through programs, while commercial sector and industrial sector will see about 2.2% and 1.0% peak reduction respectively. Those savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

B.3.3 Total Conservation Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated by sector. Winter peak demand savings by TS were summarized in Table B.3.3. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings, along with the impact of distributed generation resources, were applied to gross demand to determine net peak demand for further planning analyses.

Table B.3.3 | Forecast of Expected Winter Peak Demand Savings (MW) Due to Codes and Standards and Funded CDM Programs - by Station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
DA Watson TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Echo River TS	0.11	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.24	0.27	0.30	0.32	0.33	0.34	0.34	0.34
Goulais Bay TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Limer TS	0.11	0.19	0.19	0.19	0.15	0.15	0.15	0.15	0.15	0.15	0.17	0.19	0.23	0.25	0.28	0.30	0.32	0.32	0.32	0.32
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.02	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.06	0.06	0.06	0.06
Chapleau DS	0.07	0.12	0.12	0.12	0.10	0.10	0.10	0.10	0.10	0.10	0.12	0.13	0.16	0.18	0.20	0.22	0.23	0.23	0.23	0.23
Chapleau MTS	0.03	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.06	0.07	0.07	0.08	0.09	0.09	0.09	0.09	0.09
St. Mary's TS	0.91	1.58	1.54	1.54	1.16	1.16	1.13	1.12	1.12	1.08	1.17	1.29	1.46	1.60	1.76	1.87	1.93	1.91	1.88	1.86
Tarentorus TS	1.16	2.02	1.97	1.98	1.49	1.48	1.45	1.43	1.43	1.39	1.50	1.66	1.88	2.05	2.25	2.40	2.47	2.44	2.41	2.38
Total	**2.56**	**4.45**	**4.36**	**4.39**	**3.33**	**3.32**	**3.27**	**3.23**	**3.23**	**3.15**	**3.45**	**3.84**	**4.39**	**4.82**	**5.32**	**5.69**	**5.87**	**5.84**	**5.79**	**5.74**

B.4 Distributed Energy Resources Assumptions in ELS Forecast

Besides conservation savings, the expected peak contribution of existing and contracted DERs in the area were also taken into account.

Table B.4 | DER Forecast by Station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DA Watson TS	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Echo River TS	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.16	0.12	0.08	0.02	0.01	0.00	0.00	0.00
Goulais Bay TS	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Limer TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau DS	2.65	2.65	2.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau MTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
St. Mary's TS	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	0.23	0.18	0.16	0.16	0.16	0.14	0.00	0.00
Tarentorus TS	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	0.14	0.10	0.06	0.03	0.03	0.02	0.00	0.00	0.00

B.5 Final Peak Forecast by Station

After taking the median weather forecast provided by LDCs and applying the CDM assumptions above, forecasts were adjusted to extreme weather. The final peak demand forecasts, by station, are provided below:

Table B.5 | Winter Peak Demand Forecast (MW) by Station

Transformer Station	2019	2020	2021	2022	2023	2024	2025 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	1.65	1.66	1.66	1.67	1.67	1.68	1.69	1.69	1.71	1.72	1.73	1.74	1.76	1.78	1.79	1.81	1.83	1.85	1.86	1.88
DA Watson TS	8.53	8.57	8.55	8.56	8.57	8.58	8.60	8.63	8.67	8.71	8.75	8.80	8.87	8.93	8.99	9.06	9.13	9.20	9.26	9.32
Echo River TS	14.18	14.23	14.19	14.19	14.17	14.18	14.20	14.23	14.28	14.33	14.38	14.45	14.57	14.67	14.80	14.95	15.06	15.17	15.25	15.33
Goulais Bay TS	8.53	8.56	8.55	8.56	8.56	8.57	8.59	8.62	8.65	8.70	8.74	8.79	8.84	8.90	8.97	9.03	9.11	9.18	9.24	9.30
Limer TS (proposed TS)	13.18	13.74	13.81	13.88	13.99	54.00	54.00	54.00	54.00	54.00	54.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00
Andrews TS	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Mackay TS	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Northern Av TS	2.50	2.51	2.50	2.51	2.51	2.51	2.52	2.53	2.54	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.67	2.70	2.71	2.73
Chapleau DS	6.31	6.47	6.51	9.24	9.32	9.38	9.44	9.51	9.59	9.68	9.76	9.84	9.94	10.03	10.13	10.23	10.33	10.44	10.53	10.63
Chapleau MTS	4.47	4.36	4.44	4.19	4.69	4.58	4.59	3.89	4.21	4.15	4.14	4.27	4.27	4.27	4.27	4.28	4.29	4.29	4.29	4.30
PUC Distribution Inc.	120.7	119.5	117.5	115.9	114.2	112.7	111.4	110.0	108.9	107.9	106.8	109.7	116.5	115.7	114.9	114.2	113.6	112.9	112.3	111.5

B.6 Duration Forecast Methodology

B.6.1 General Methodology

A load duration forecast consists of a series of year long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are studied to determine the feasibility of using non-wires alternatives to address needs in the region, and to determine which type of non-wires alternatives may be best suited to meet the needs.

Hourly load forecasting was conducted on a station-level, using a multiple linear regression with approximately five years' worth of historical hourly load data. Firstly, a density-based clustering algorithm was used for filtering the historical data for outliers (including fluctuations possibly caused by load transfers, outages, or infrastructure changes).

Subsequent to the removal of outliers, the historical hourly data was combined with select predictor variables to perform a multiple linear regression and model the station's hourly load profile. For the ELS region, the following predictor variables were used:

- Calendar factors (such as holidays and days of the week)
- Weather factors (including temperature, dew point, wind speed, cloud cover, and fraction of dark; both weekday and weekend heating, cooling, and dead band splines were modelled)
- Demographic factors (population data[2])
- Economic factors (employment data[3])

Model diagnostics (training mean absolute error, testing mean absolute error) were used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. While future values for calendar, demographic, and economic variables were incorporated in a relatively straightforward manner, the unreliability of long-term weather forecasts necessitated a different approach for predicting the impact of future weather.

Each future date was first modelled using historical weather data from the equivalent day of year throughout the past 10 years. Additionally, to fully assess the impact of different weather sequences against the other non-weather variables, the historical weather for each of the 10 previous years was shifted both ahead and behind up to seven days, resulting in 15 daily variations. This approach ultimately led to 150 possible hourly load forecasts for each future year being forecast. For example:

- 10 years of historical weather data ×15 weather sequence shifts =150 weather scenarios for each year being forecast
- E.g., June 2nd 2025 was forecasted assuming the historical weather from every May 26th to June 9th that occurred between 2011 and 2020.

Subsequently, the list of 150 forecasts were ranked in ascending order based on their median values. Load duration curves which illustrate this ranking can be seen in Figure B-5.

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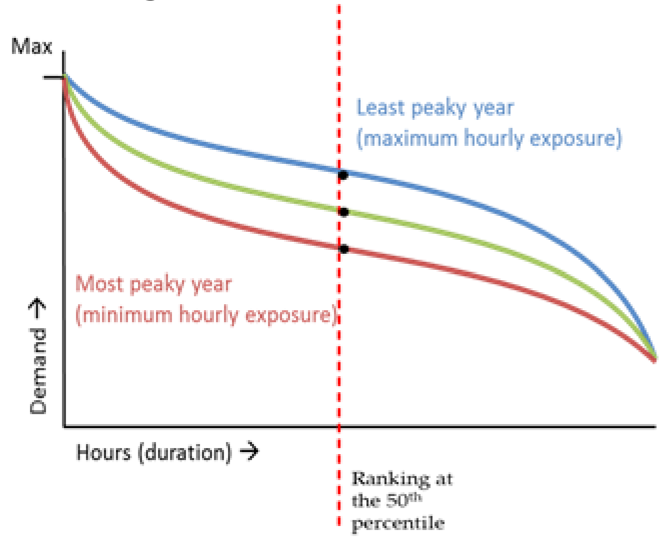
[2] Sourced from the Ministry of Finance and Statistics Canada

[3] Sourced from the Centre for Spatial Economics, IHS Markit Ltd., and the Conference Board of Canada

Figure B.6 | Example of Ranking Load Duration Curves Created from Hourly Load Profiles



The forecast in the 3rd percentile was chosen as the "Extreme Peak" (extreme profile, red curve) and the forecast in the 50th percentile was chosen was the "Median Peak" (median profile, green curve).

The yearly forecasts were scaled to their respective maximums from the peak demand forecast, and added together to form a single multi-year forecast.

B.6.2 St. Mary's MTS and Tarentorus MTS

For the purpose of this IRRP, need characterization was done for St Mary's MTS and Tarentorus MTS. These stations are prioritized first in the existing GLP Instantaneous L/R scheme and are located in an area linked to the needs identified in the study (i.e., they are served by Third Line TS).

The historical hourly data for both stations was combined and one linear regression model was used. Once the 150 normalized forecasts were created, they were scaled to PUC Distribution's extreme weather peak demand forecast. The load duration forecast provided information regarding the amount by which the load is expected to exceed the limit of 42 MW (forecasted peak demand less load rejection required for the P21G + P22G double contingency) as well as the amount of time spent over the limit, or the total event hours. Table B.6.2 shows the annual energy requirements based on this information.

Table B.6.2 | Energy Required to Address Reliability Needs at Third Line TS

	2020	2025	2030	2035	2040
Annual Energy Need (MWh)	224,000	196,000	168,000	153,000	122,000

Figure B.6.2 is a visual representation of the percentage of the total event hours that are associated with each range of capacity need for the 2019 and 2040 load duration forecasts. For example, in 2019 approximately 4% of the total time spent over the limit was at least 10 MW over and was in the first hour of the day.

Figure B.6.2 | Energy Not Served for St. Mary's MTS and Tarentorus MTS

2019

Capacity Need (MW)																								
90																								
80																								
70											0.02%							0.02%	0.02%	0.02%	0.02%			
60								0.02%	0.1%	0.1%	0.05%	0.05%	0.05%	0.05%	0.05%	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.02%
50								0.4%	1%	1%	0.5%	0.3%	0.4%	0.3%	0.3%	0.4%	1%	1%	1%	1%	1%	0.5%	0.1%	0.05%
40	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	2%	3%	3%	3%	2%	2%	1%	0.5%
30	1%	1%	1%	1%	1%	1%	2%	3%	3%	3%	2%	2%	2%	2%	2%	2%	3%	3%	4%	4%	4%	3%	3%	2%
20	3%	2%	2%	2%	2%	3%	4%	4%	4%	3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	3%
10	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%	4%	3%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
0	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
HOUR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

2040

Capacity Need (MW)																								
90																								
80																								
70													0.03%											
60													0.1%	0.1%	0.1%	0.03%								
50										0.1%	0.1%	0.2%	0.4%	0.4%	0.2%	0.2%	0.2%	0.03%						
40									0.2%	0.4%	1%	1%	1%	1%	1%	1%	1%	1%	0.3%	0.03%				
30	0.03%					0.03%	0.2%	0.4%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	0.4%	0.3%	0.2%	0.1%
20	0.3%	0.3%	0.3%	0.3%	0.3%	0.5%	1%	1%	2%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%	2%	1%	1%	1%
10	2%	2%	1%	1%	2%	2%	2%	3%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%	3%	3%	2%
0	4%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%	5%	4%	4%	5%	5%	4%	5%	5%	5%	4%	4%	4%
HOUR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

Appendix C. Options and Assumptions

C.1 Economic Assumptions

An economic analysis was performed in order to compare the relative net present value ("NPV") of the feasible IRRP alternatives, including the lowest cost generation option that could meet the characteristics of the need and transmission options. The relative performance of the option (or combination of options) NPVs informs the identification of the most cost-effective options for meeting the region's needs.

Local Generation

The least-cost local generation alternative that could meet the characteristics of the region's needs is a new combined cycle gas turbine (CCGT) together with continued participation of existing demand response resources; the estimated NPV of this 65 MW generator is $250 Million. A local generator sited strategically in the 115 kV system could technically meet the reliability needs identified in the region, including the thermal overload of 115 kV circuit Sault No.3 and to prevent arming of load following the PxG contingencies. However, the cost of implementing this alternative exceeds the sum of the individual transmission solutions being recommended as part of this plan. However, such an alternative should continue to be considered as part of the IESO's Northeast Bulk Planning Study which will consider the thermal overload of the Sault No.3.

The following is a list of the assumptions made in the economic evaluation for the local CCGT option:

- The NPV of the cash flows is expressed in 2020 $CAD.
- The NPV analysis was conducted using a 4% real social discount rate (SDR). An annual inflation rate of 2% is assumed.
- An CCGT was identified as the least-cost resource alternative. The estimated levelized capacity cost assumed is about $313/kW-yr (2020 $CAD), based on escalating values from a previous study independently conducted for the IESO. The selection of this option for comparison to the transmission alternative did not account for potential operational issues that may arise during planned maintenance activities or forced outages to the unit. The life of the CCGT was assumed to be 30 years.
- Natural gas prices were assumed to be an average of $4/MMBtu throughout the study period.
- The USD/CAD exchange rate was assumed to be 0.78 for the study period.
- Carbon pricing assumptions are similar to the assumptions in the Annual Planning Outlook (i.e. carbon pricing is calculated based on the Output Based Performance Standards. This comes out to $0.00421/kg CO_2e in 2023, growing to $0.02524/kg CO_2e in 2040).
- System capacity value was $141k/MW-yr (2020 CAD) based on the CA reference price.
- The DR values was 49k/MW-yr (2020 CAD) based on the average Northeast summer and winter DRA clearing prices from 2018-2020.

Enable Remote Arming for P21G+P22G in GLP Instantaneous Load Rejection Scheme

The estimated NPV of total costs to enable remote arming of load in the existing GLP load rejection scheme for the loss of P21G and P22G circuits is $50,000. While the scheme can be manually armed, the enabling of remote arming of load will allow IESO Control Room to arm load remotely, thus eliminating the need for the manual arming sequence and making the load rejection arming procedure more efficient.

Automate Patrick St TS Manual Load Shedding Scheme

The estimated NPV of automating the manual load-shedding scheme at Patrick St TS is $2 Million. There is an existing Patrick St TS Manual load shedding scheme designed to manage the load at Patrick St TS. Loads at Patrick St TS are normally supplied by the three 115 kV Algoma circuits and from Clergue GS and load displacement generators at Algoma Steel Inc. Following contingencies that leave only one Algoma circuit in service, manual load shedding may be required. Since this process is not instantaneous, it also exposes the remaining Algoma circuit to an extremely high flow if the second circuit was to trip during the manual load shedding sequence. This scheme was originally designed as an interim solution until a more permanent solution was employed. The automated scheme must also be expanded to arm load for the Patrick St TS 214 BKF.

Appendix D. Planning Study Results

East Lake Superior Region

Study Report

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Connecting Today.
Powering Tomorrow.

Table of Contents

1. Overview

The East Lake Superior (ELS) region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south.

The load in this area is comprised of primarily industrial, commercial and residential which peaks in the winter. Figure 1 shows the seasonal peak loading in the region over the period of five years from 2014-2018. The majority of the load is concentrated in and around the city of Sault Ste. Marie.

Figure 1 | Seasonal Peak Demand for ELS Region

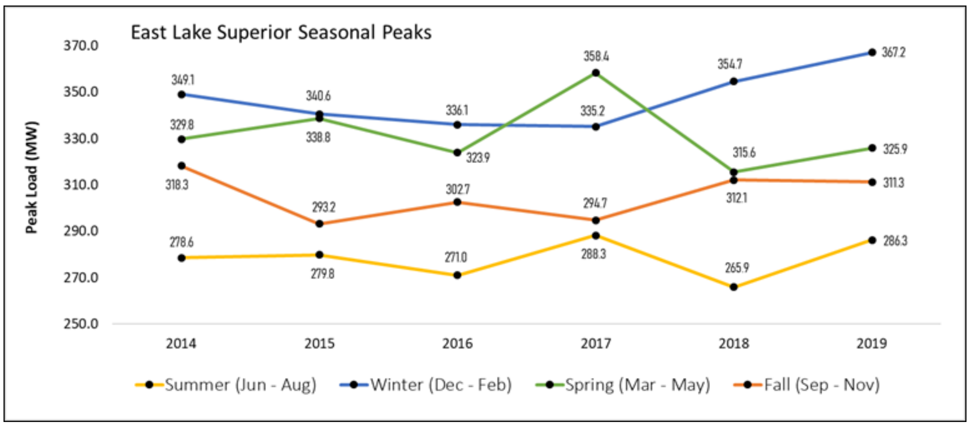
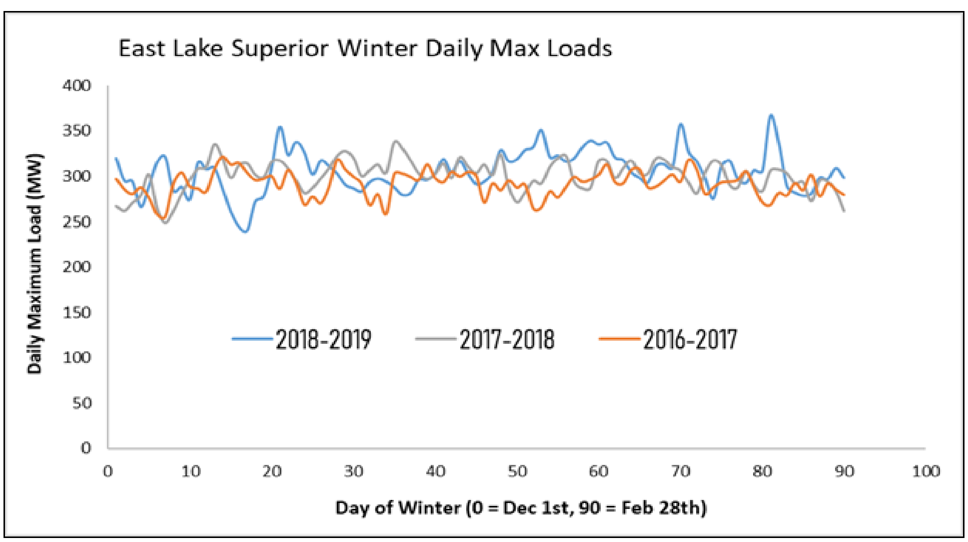


Figure 2 shows the daily winter peak load for the region from the period 2016-2019. This shows the load profile in the area is fairly flat over the winter months hovering within 10% of the peak load.

Figure 2 | Historical Daily Winter Peak Demand



Electrical supply to the region is provided through 230/115 kV autotransformers at Third Line TS, Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figure 3. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

The 230 kV transmission facilities in this area provide both regional system and bulk system functions. That is, in addition to supplying local customers, they form part of an integrated network that enables the bulk transfer of electricity across the province.

The region has over 1,200 MW of generation, including numerous hydroelectric facilities, solar and wind farms and thermal generating facilities. The transmitters in the region are Hydro One Sault Ste. Marie LP (HOSSM) and Hydro One Networks Inc. (Hydro One); the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and PUC Distribution Inc.

The single line diagram of this region is shown Figure 3 and the geographical transmission map is shown is Figure 4.

Figure 3 | East Lake Superior Single Line Diagram

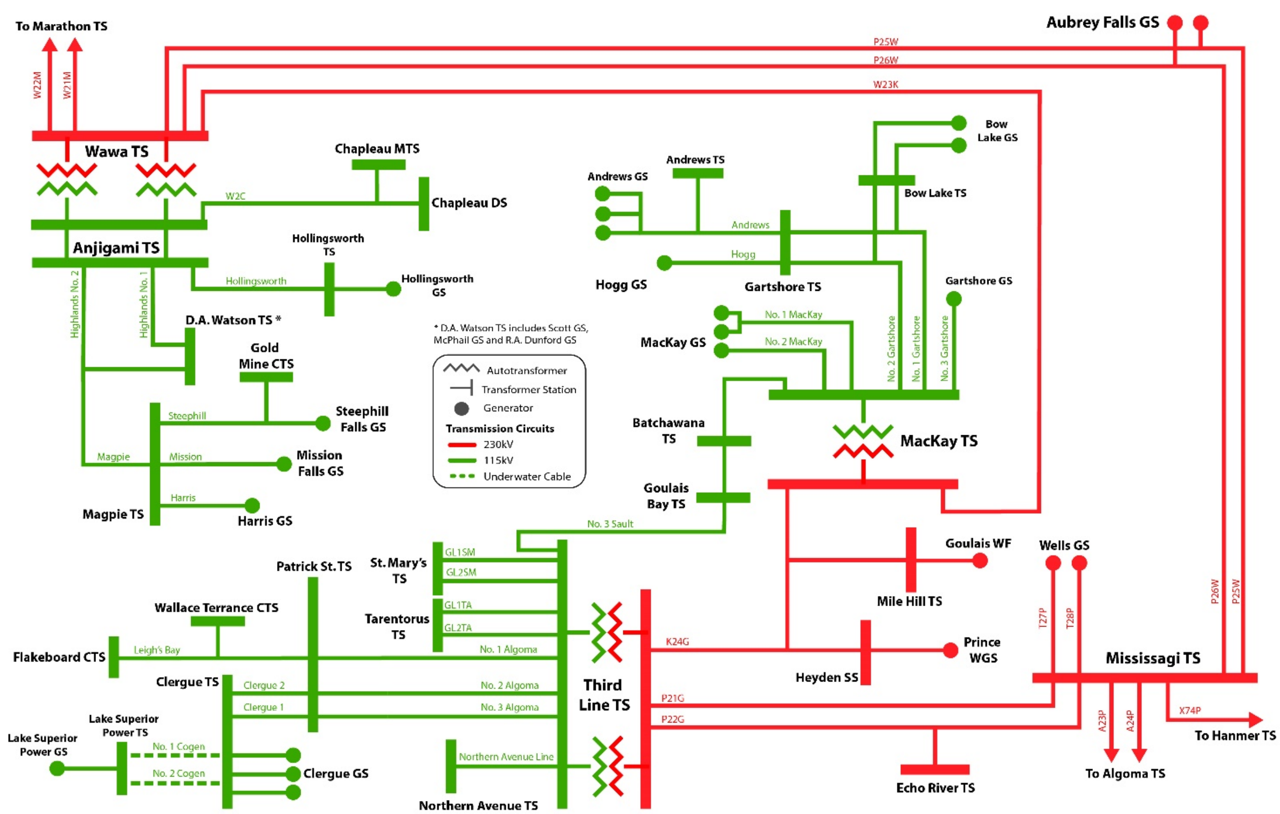
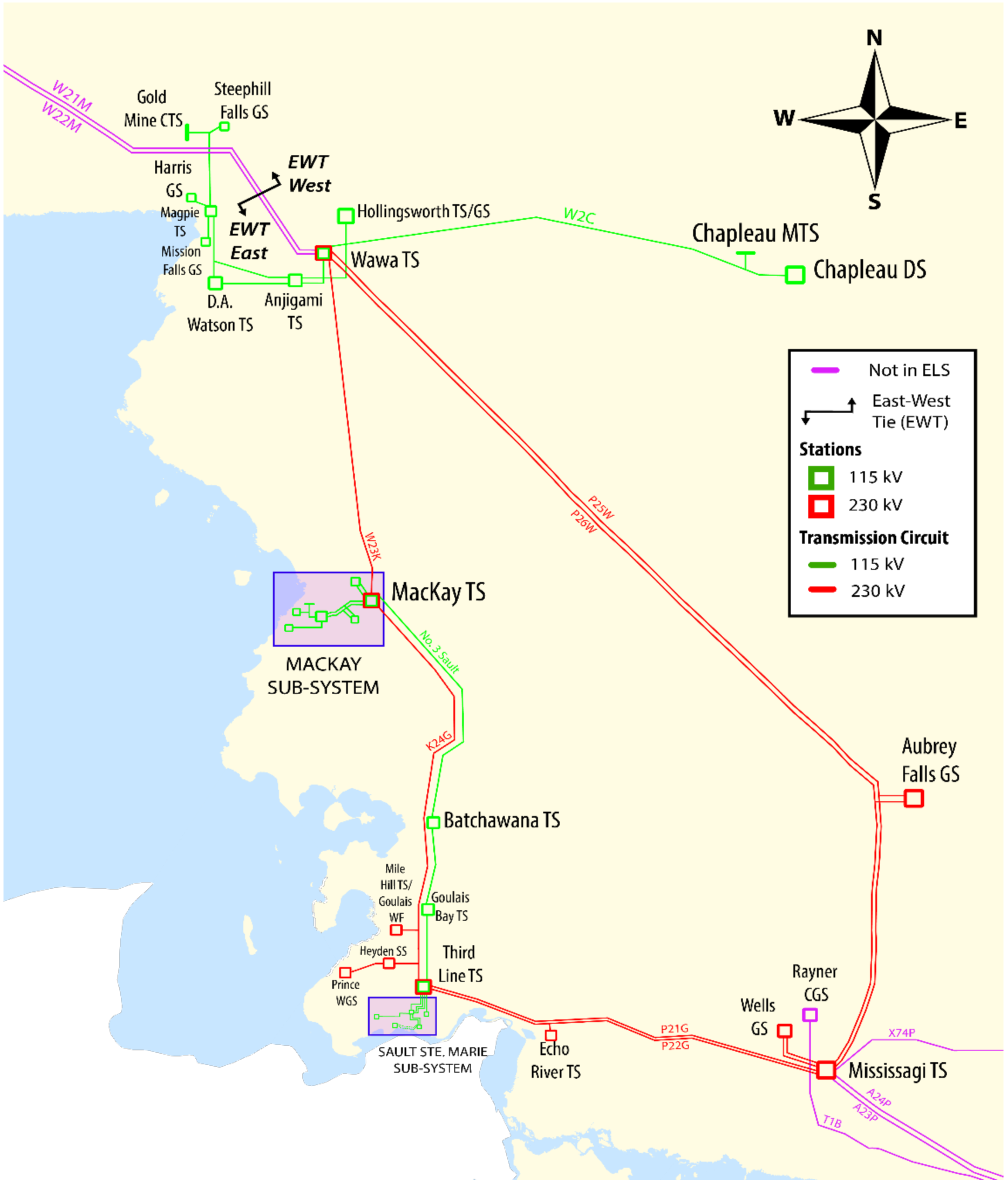


Figure 4 | East Lake Superior Transmission System



1.1 Load Forecast

Load forecast is as provided by the participating LDCs. In this region, the historical peak demand growth has been flat (neither increasing nor decreasing). For assessments concerning the regional transmission system, the non-coincident peak demand was used as a conservative approach, except for PUC Distribution Inc.'s stations where co-incident peak demand is used due to their ability to transfer loads between St. Mary's TS and Tarentorus TS during peak demand. Assessments of station-level adequacy used the same non-coincident forecast. This station level forecast snapshot for years 2020, 2025, 2030, and 2040 (end of planning horizon) is provided in Table 1 below.

Where needs are identified in the near term to medium term, further studies will be performed to refine the need using interim year forecast values to determine more precisely the load level and/or year the need arises.

Where appropriate, hourly load profiles may also be developed to aid in the evaluation of alternative such as non-wires options. The load forecast for industrial loads will be based on the information provided by individual load customers, historical hourly demand, information provided by LDCs, or other sources.

A load's power factor of 0.9 lagging is assumed at the Designated Metered Point. If voltage issues are discovered in the assessment, power factor sensitivities will be tested.

Table 1 | Station Load Forecast for ELS Region by LDC

Station	LDC	2020	2025	2030	2040
Chapleau DS	H1-SSM	6.4	9.6	9.6	9.6
St Mary's TS and Tarentorus TS	SSM PUC	116.1	112.3	111.1	112.2
Andrew TS	Algoma Power	0.2	0.2	0.2	0.2
Northern Ave TS	Algoma Power	3.2	3.3	3.4	3.6
Anjigami TS /Hollingsworth TS	Algoma Power	13.7	51.6	51.9	52.4
Mackay TS	Algoma Power	0.04	0.04	0.04	0.04
Echo River TS	Algoma Power	14.3	14.8	15.0	15.8
DA Watson TS	Algoma Power	8.6	8.9	9.2	9.6
Batchawana TS	Algoma Power	1.8	1.9	1.9	2.0
Goulais TS	Algoma Power	8.6	9.5	9.7	10.1

1.2 Local Generation Assumptions

Transmission connected local generation facilities are tabulated in Table 2. Distribution connected generation facilities, are considered load modifiers and therefore, their output is reflected as a net reduction in load as described in Appendix B of the IRRP Appendices.

Capacity assumptions in the basecase consider the amount of generation that is dependable for the majority of the time. For the hydroelectric facilities, their capacity is taken as the output that is coincident with the region's overall 98% dependable hydroelectric output.

The dependable generation output at each facility is represented by the minimum number of generator units required to produce that power. Furthermore, any units available to provide condensing services were modeled in accordance with their latest Reactive Support and Voltage

Control (RSVC) contracts. This ensures that reactive power support is reasonably, but conservatively estimated.

The wind generation facilities were modelled based on their summer and winter capacity contribution factors as per IESO's Reliability Outlook, multiplied by their peak capacity.

Table 2 | Local 98% Dependable Generation Capacity

Station	Fuel	Winter	Summer
Andrews	Hydro	0.03	0.09
Clergue	Hydro	41.86	34.02
DA Watson	Hydro	12.76	3.60
Gartshore	Hydro	0.01	0.06
Harris	Hydro	1.98	0
Hogg	Hydro	0.01	0.06
Hollingswoth	Hydro	3.21	1.50
Mackay	Hydro	0.03	0.12
Mission Falls	Hydro	2.55	0
Steephills	Hydro	1.79	0
Prince Wind Farm	Wind	5.44	1.85
Bow Lake	Wind	3.01	1.36
Goulais Wind	Wind	0	0.78

1.3 Major Interface Flows

Table 3 shows the major interfaces that impact this region. The interface flow assumptions are based on the maximum transfer capability of each interface. The baseline assumption will be to assume interface flows at ~95% of their transfer capability to ensure that load growth in the area does not penalize transfer capability in this region.

Table 3 | System Interface Flows

Interface	Definition	Transfer Capability (MW)	Interface Assumption (MW)
GLP-Inflow	MW Flow west at Mississagi TS on P21G and P22G plus MW flow into Third Line TS on K24G	295	280
East West Tie West (EWTW)	MW flow west at Wawa TS on W21M and W22M	350 (450 after 2022	332 (450 after 2022)
East West Tie East (EWTE)	MW flow east at Wawa TS on W21M and W22M	325 (450 after 2022)	309 (450 after 2022)

1.4 Monitored Circuits and Sections

Table 4 shows the winter and summer ratings for circuits and their corresponding circuit sections that will be monitored in this region. These ratings are derived from Hydro One's Power System Database (PSDb).

Table 4 | Monitored Circuits and Ratings

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
W23K-1	Wawa TS	MacKay JCT	1420	1720	2000	1220	1570	1860
W23K-2	MacKay JCT	MacKay TS	1459	1459	2000	1255	1255	1945
K24G-1	Third Line TS	Heyden JCT	1459	1459	2000	1255	1255	1945
K24G-2	Heyden JCT	Mile Hill JCT	1459	1459	2000	1255	1255	1945
K24G-3	Mile Hill JCT	MacKay TS	1459	1459	2000	1255	1255	1945
K24G-4	Heyden JCT	Heyden CTS	1459	1459	2000	1255	1255	1945
K24G-5	Mile Hill JCT	Mile Hill CTS	1459	1459	2000	1255	1255	1945
P21G-1	Mississagi TS	P21G POLE 6 JCT	1115	1115	1200	954	954	1064
P21G-2	P21G POLE 6 JCT	Third Line TS	1115	1115	1200	954	954	1064
P22G-1	Mississagi TS	Echo River TS	1115	1115	1200	954	954	1064

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
P22G-2	Echo River TS	Third Line TS	1115	1115	1200	954	954	1064
P25W-1	Mississagi TS	Aubrey Falls JCT	1020	1130	1190	880	1010	1070
P25W-2	Aubrey Falls JCT	Wawa TS	1020	1020	1020	880	880	880
P25W-3	Aubrey Falls JCT	Aubrey Falls CGS	1020	1130	1190	880	1010	1070
P26W-1	Mississagi TS	Aubrey Falls JCT	1020	1130	1190	880	1010	1070
P26W-2	Aubrey Falls JCT	Wawa TS	1020	1020	1020	880	880	880
P26W-3	Aubrey Falls JCT	Aubrey Falls CGS	1020	1130	1190	880	1010	1070
Sault No.3-1	Third Line TS	Goulais Bay TS	200	200	200	200	200	200
Sault No.3-2	Goulais Bay TS	Batchawana TS	200	200	200	200	200	200
Sault No.3-3	Batchawana TS	MacKay TS	200	200	200	200	200	200
Sault No.3-4	Goulais Bay TS	Goulais Bay TS	600	600	600	600	600	600
Sault No.3-5	Batchawana TS	Batchawana TS	600	600	600	600	600	600
GL1TA	Third Line TS	Third Line JCT #1	784	784	784	672	672	672
GL2TA	Third Line TS	Third Line JCT #1	784	784	784	672	672	672
GL1SM	Third Line TS	Third Line JCT #2	784	784	784	672	672	672
GL2SM	Third Line TS	Third Line JCT #2	784	784	784	672	672	672
W2C-1	Wawa TS	Chapleau JCT	320	360	360	280	320	320
W2C-3	Chapleau JCT	Chapleau DS	320	380	420	280	350	390
W2C-4	Chapleau JCT	Chapleau DS	320	380	420	280	350	390
W2C-5	Chapleau JCT	Chapleau MTS	370	440	490	320	400	460
No.1 Algoma	Third Line TS	Patrick St CTS	627	627	681	538	538	578
No.2 Algoma	Third Line TS	Patrick St CTS	784	784	887	672	672	751

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
No.3 Algoma	Third Line TS	Patrick St CTS	784	784	887	672	672	751
Northern Avenue	Third Line TS	Northern Avenue TS	784	784	847	672	672	720
No. 1 Clergue	Patrick St CTS	Clergue TS	627	627	660	538	538	562
No. 2 Clergue	Patrick St CTS	Clergue TS	627	627	660	538	538	562
Leigh's Bay	Patrick St CTS	Wallace Sub CTS	837	837	898	717	717	763
Leigh's Bay	Wallace Sub CTS	Flakeboard CTS	837	837	898	717	717	763
No. 1 MacKay	MacKay TS	MacKay CGS	627	627	660	538	538	562
No. 2 MacKay	MacKay TS	MacKay CGS	627	627	660	538	538	562
No. 1 Gartshore	MacKay TS	Bow Lake JCT #2	627	627	660	538	538	562
No. 1 Gartshore	Bow Lake JCT #2	Gartshore SS	627	627	660	538	538	562
No. 2 Gartshore	MacKay TS	Bow Lake JCT #2	627	627	660	538	538	562
No. 2 Gartshore	Bow Lake JCT #2	Gartshore SS	627	627	660	538	538	562
Andrews	Andrews JCT #2	Andrews TS	365	365	365	313	313	313
Hogg	Gartshore SS	Hogg CGS	414	414	414	355	355	355
No. 3 Gartshore	Gartshore SS	Gartshore CGS	627	627	660	538	538	562
Hollingsworth	Anjigami TS	Anjigami JCT #2	541	541	561	464	464	479
No. 1 High Falls	Anjigami TS	DA Watson TS	627	627	627	464	464	479

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
No. 2 High Falls	Anjigami JCT	DA Watson TS	490	490	490	420	420	420
Magpie	DA Watson TS	Magpie SS	784	784	847	672	672	720
Steephill	Magpie SS	River Gold JCT	627	627	660	538	538	562
Harris	Magpie SS	Harris CGS	627	627	660	538	538	562
Mission	Magpie SS	Mission Falls CGS	627	627	660	538	538	562

1.5 Special Protection Schemes

Table 5 | Relevant Remedial Action Schemes (RAS)

Facility	Description
Third Line TS	a) GLP Instantaneous Load Rejection Scheme, b) Northwest Load Rejection Scheme, and c) Under Voltage Sault Local Load Rejection Scheme
Mackay TS	MacKay TS – No.3 Sault 115 kV Line – Generation Rejection (G/R) Scheme

There are three existing Remedial Action Schemes (RASs) located at Third Line TS: a) GLP Instantaneous Load Rejection Scheme, b) Northwest Load Rejection Scheme and c) Under Voltage Sault Local Load Rejection (L/R) Scheme. The GLP Instantaneous Load Rejection Scheme have six load blocks that can be armed and shed 115kV connected load for either the loss of both Third Line transformers or the loss of both P21G and P22G. The Northwest Load Rejection Scheme can be armed for the automatic load rejection which will be initiated from Mississagi TS for the loss of both A23P and A24P in "MISS x ALG Zone", or S22A or X27A in the "ALG x SUD Zone". Five protective relays (R1 to R5) control the arming of five load blocks (Load Block 1 to Load Block 5) of the Northwest Load Rejection Scheme, which are armed in a preferred order to minimize impact on certain critical loads such as hospitals. The Under Voltage Sault Local Load Rejection (L/R) Scheme is designed to shed loads connected to the 115kV side of Third Line TS in the event of the voltage dropping below a setpoint. This setpoint is currently set at 108kV. This scheme uses the same six load blocks in GLP Instantaneous Load Rejection Scheme.

The primary purpose of the MacKay TS – Sault No.3 115 kV circuit – Generation Rejection (G/R) Scheme is to ensure the post-contingency load on No.3 Sault 115 kV circuit is within its continuous rating for loss of T2 230/115 kV autotransformer at MacKay TS or for the loss of K24G 230 kV line between MacKay TS and Third Line TS under specific transmission system conditions.

The scheme is expected to be armed when Sault No.3 circuit is operated in parallel with the normal 230 kV system and the following conditions exist:

1) The total generation flow out of MacKay TS exceeds the continuous rating of the Sault No.3 circuit which will result in a post contingency flow above the continuous rating for the loss of T2 including the 115 kV NORTH BUS and 230 kV T2H BUS or

2) East-West system flows are high in the east direction and GLP system generation is high which will result in a post contingency flow above the continuous rating of Sault No.3 for loss of K24G 230 kV circuit.

2. Credible Scenarios and Planning Events

The following sections below outline the scenarios and contingencies that have been assessed. For practical purposes, recognizing the level of precision of demand forecasts, the study will initially focus on analyzing scenarios and contingencies for the conditions in the following years; 2025 (to represent the near-term planning horizon), 2030 (to represent the medium-term planning horizon), and 2035 and 2040 (to represent the long-term planning horizon).

2.1 Studied Scenarios

Table 6 describes the various scenarios that were studied in this regional planning cycle. In addition, high industrial growth around the proposed Limer TS was also included as a sensitivity analysis. Limer TS is a newly proposed 115/44kV transformer station which will be connected between Hollingsworth TS and Anjigami TS to support the proposed load growth in this sub-region. This was applied to the most limiting contingencies found in the scenarios below. The results in this report reflect that sensitivity.

Table 6 | Scenarios to be Assessed

Scenario Name	Scenario Type	Scenario Description
Scenario 1	Winter peak, extreme weather, long-range forecast	• Dependable winter generation • Bulk transfer at 5% less than TTC • East West Transfer flowing east
Scenario 2	Winter peak, extreme weather, long-range forecast	• Dependable winter generation • Bulk transfer at 5% less than TTC • East West Transfer flowing west
Scenario 3	Summer peak, extreme weather, long-range forecast	• Dependable summer generation • Bulk transfer at median historical levels • East West Transfer flowing east
Scenario 4	Summer peak, extreme weather, long-range forecast	• Dependable summer generation • Bulk transfer at median historical levels • East West Transfer flowing west
Scenario 5	Median low-demand	• Dependable winter generation • Bulk transfer at median historical levels • East West Transfer flowing west

Table 7 describes the various types of Planning Events that were simulated while conducting the studies in this regional plan.

Table 7 | Contingencies Assessed

Pre-Contingency State	Contingency
All Elements In-Service	[Single Element Contingencies (N-1)]
All Elements In-Service	[Common Tower Contingencies (N-2)]
All Elements In-Service	[Breaker Failure Contingencies (N-2)]
[One Element] Out-of-service	[Single Element Contingencies (N-1-1)]
One generating unit out-of-service	Single Element Contingencies (N-G-1)

2.2 Studied Contingencies

Table 8 | Studied Single Contingencies

P21G	P22G	P25W	P26W	W23K	K24G	No 3 Sault	W2C	Northern Ave.
No.1 Algoma	No.2 Algoma	No.3 Algoma	Mississagi A- bus*	Mississagi K-bus*	No.1 Clergue	No.2 Clergue	GL1SM	GL2SM
GL1TA	GL2TA	No.1 Gartshore	No.2 Gartshore	No.1 High Falls	No.2 High Falls	Third Line T1	Third Line T2	Leigh's Bay
No.1 Mackay	No.2 Mackay	No.3 Gartshore	Andrews	Hogg	Hollingsworth	Magpie	Steephill	Harris
Mission	Anjigami T1	Hollingsworth T2						

*Bus contingencies are only simulated for the All-in-service scenario

Table 9 | Studied Double Contingencies

P21G+P22G	P25W+P26W	No.1 Algoma+No.2 Algoma	Patrick St 214 BKF	Third Line 402 BKF	Third Line 408 BKF
Mississagi AL25 BKF	Mississagi L24L25 BKF	Mississagi KL24 BKF	Mississagi L26L74 BKF	Mississagi KL74 BKF	Wawa L23L25 BKF
Wawa L21L25 BKF	Wawa HL21 BKF	Wawa AL23 BKF	Third Line 412 BKF	Third Line 405 BKF	Wawa DL1 BKF
Patrick St 205 BKF	Wawa KL2 or DL2 BKF	Wawa AH BKF	Mississagi L24L25 BKF	Mississagi L23L26 BKF	Mississagi AL23 BKF

3. Planning Criteria

The study will adhere to planning criteria in accordance with planning events and performance as detailed by:

- North American Electric Reliability Corporation ("NERC") TPL-001 "Transmission System Planning Performance Requirements" ("TPL-001"), and
- IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC").

Applying ORTAC, NERC and NPCC criteria to assess supply capacity and reliability needs, the following categories of needs can be identified:

- Supply capacity requirements were assessed to analyze the capability of the system to reliably supply load in the ELS region.
- Load security describes the amount of load susceptible to supply interruptions in the event of a major transmission outage.
- Load restoration describes the electricity system's ability to restore power to those customers affected by a major transmission outage within reasonable timeframes. Restoration from a normal outage should remain under eight hours, consistent with ORTAC.
- Step-down station capacity needs were identified by comparing forecast demand growth to the station's 10 day Limited Time Rating ("LTR"), or thermal capacity, to determine the net incremental requirement for transformation capacity in the area.

3.1 Supply Capacity Requirements

3.1.1 Loss of Third Line T1/T2

Loss of one of the Third Line TS autotransformers causes the companion transformer to be loaded close to its LTR rating. This is an existing situation. Once the Sault No.3 circuit comes into service in 2023 and beyond, the loading on the remaining autotransformer is reduced.

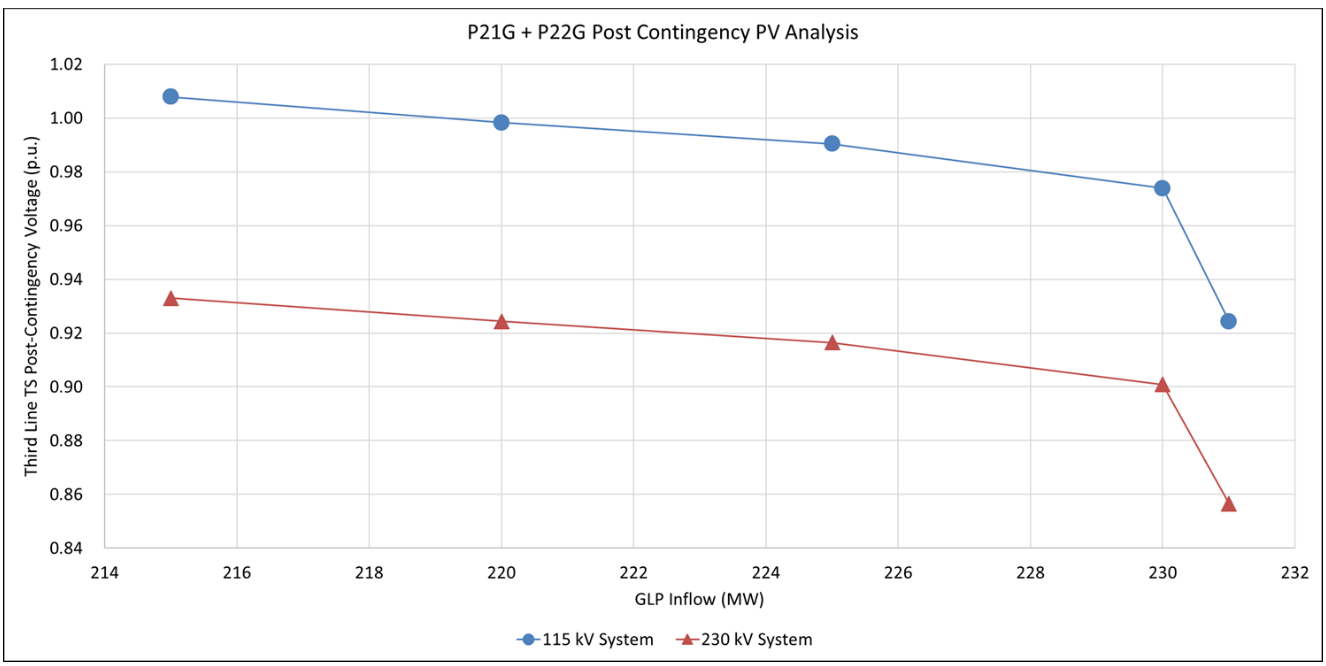
Table 10 | Third Line Autotransformer Loading Following Loss of Companion for EWTW Flow, Scenario 1

Limiting Contingency	Limiting Element	LTR Rating (MVA)	2020 Loading (MVA)	2025 Loading (MVA)	2030 Loading (MVA)	2040 Loading (MVA)
Third Line T1	Third Line T2	280	279	256	257	256

3.1.2 Loss of P21G and P22G

Loss of P21G and P22G causes voltage collapse at Third Line and other ELS stations throughout the planning period. This is illustrated in the figure below.

Figure 4 | Post Contingency PV Analysis



3.1.3 Loss of Two Algoma Circuits

Following the loss of one Algoma circuit, the loss of a second Algoma circuit would result in the remaining third Algoma circuit getting overloaded beyond its STE. The existing solution is the Patrick St Manual load shedding scheme which was designed to manage load manually to minimize the impact on the remaining Algoma circuit. However, it does not ensure the LTE rating of the remaining circuit to be respected. It was designed as an interim solution until a more permanent solution was implemented.

Table 11 | Loading on Algoma 1 Circuit Following Loss of Other Two Algoma Circuits, all Scenarios

Limiting Contingency	Limiting Element	From	To	LTE Rating (MVA)	STE Rating (MVA)	2020 Loading (MVA)	2025 Loading (MVA)	2030 Loading (MVA)	2040 Loading (MVA)
Algoma No. 2 + Algoma No. 3	Algoma No. 1	Third Line TS	Patrick St TS	627	681	727	756	774	767

3.1.4 Patrick St 214 BKF

A Breaker Failure (BKF) of the 214 breaker at Patrick St TS results in the loss of two out of the three 115 kV circuits from Third Line TS to Patrick St TS, resulting in the remaining Algoma No. 1 circuit overloaded beyond its STE rating for all years. This is also shown in Table 11 above.

3.1.5 No. 3 Sault Line Overload

During a P25W or P26W outage, a K24G contingency results in thermal overload of Sault No.3 circuit beyond its upgraded STE ratings starting in 2023.

Table 12 | Loading on No.3 Sault Circuit Following a PxW Outage and K24G Contingency, Scenario 2

Outage	Limiting Contingency	Limiting Element	From	To	LTE Rating (Amps)	STE Rating (Amps)	2020 Loading (Amps)	2025 Loading (Amps)	2030 Loading (Amps)	2040 Loading (Amps)
PxW	K24G	No. 3 Sault	Thid Line TS	Goulais Bay TS	541	561	N/A	658	718	734
PxW	K24G	No. 3 Sault	Goulais Bay TS	Batchawana TS	541	561	N/A	620	670	683
PxW	K24G	No. 3 Sault	Batchawana TS	Mackay TS	541	561	N/A	613	660	672

In addition, when one of the Third Line TS autotransformers is initially experiencing an outage, Sault No.3 circuit will need to be in-service (after its proposed upgrades) in order to prevent overloading of the companion Third Line TS autotransformer. However, if the second autotransformer is also lost, Sault No.3 circuit will be overloaded beyond its upgraded STE rating and cause a voltage collapse in the area served by Third Line TS.

3.1.6 Hollingsworth T1 and T2 Overload

For loss of Anjigami TS, in this sub-region, there is an overload on Hollingsworth T1 and T2, starting in the year 2024. This is shown in Table 13 below. The Needs Assessment report also identified that Hollingsworth TS – Transformer T2 / Anjigami TS – Transformer T1 will become overloaded due to a large customer connecting to the 44 kV system.

The incremental growth scenario, which incorporates the addition of new industrial load in this sub-region around Limer TS worsens the need identified in Table 13 to a point that loss of Anjigami T1 results in significant voltage decline in the area.

Table 13 | Loading on Hollingsworth T1 and T2 Following Anjigami T1 Contingency, all Scenarios

Limiting Contingency	Limiting Element	LTE Rating (MVA)	STE Rating (MVA)	2020 Loading (MVA)	2025 Loading (MVA)	2030 Loading (MVA)	2040 Loading (MVA)
Anjigami T1	Hollingsworth T1	33.7	52.5	11	60	62	62
Anjigami T1	Hollingsworth T2	28	28	17	60	62	62

3.2 Step-Down Station Capacity Requirements

As shown in Table 14., there is step-down station capacity needs identified in the Anjigami/Hollingsworth sub-region within the ELS region.

Table 14 | Step-down Station Capacity Needs

Station	Cont. Rating (MVA)	LTR Rating (MVA)	2020 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Andrews TS	5.0	5.0	0.22	0.22	0.22	0.22
Batchawana TS	4.3	4.3	1.64	1.72	1.78	1.92
DA Watson TS	75.0	75.0	8.47	8.76	9.01	9.51
Echo River TS	25.0	25.0	14.05	14.46	14.79	15.61
Goulais Bay TS	15.0	15.0	8.46	8.75	8.99	9.47
Limer TS (proposed TS)	TBD	TBD	37.0	54.0	56.0	56.0
MacKay TS	0.5	0.5	0.04	0.04	0.04	0.04
Northern Avenue TS	5.0	5.0	2.48	2.56	2.64	2.78
Chapleau DS	17.05	17.05	6.37	9.62	10.07	11.32
Chapleau MTS	10	10	4.31	4.68	4.37	4.29
St Mary's MTS + Tarentorus MTS	210	210	116.11	112.30	111.09	112.21

3.3 Load Security

Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. The transmission system must exhibit acceptable performance while following specified design criteria contingencies. Load security criteria, as described by ORTAC Section 7.1, specify a load interruption limit of 150 MW for single element contingencies and 600 MW for double element contingencies. A summary of the load security criteria can be found in Table 6.3 of the IRRP Report.

The demand forecast in the ELS region remains below the load security criteria outlined in ORTAC. No load security need has been identified in the planning timeframe. For single contingencies, there is no loss of load greater than 150 MW by configuration and for double contingencies, there is no loss of load greater than 600 MW.

3.4 Load Restoration

The Needs Assessment provided information on restoration challenges at Andrew TS, Batchawana TS, Goulais TS and Echo River TS. The solution to the restoration will be local to the area and will be coordinated with the transmitter and impacted LDC. Following the loss of both Third Line autotransformers and Sault No.3 circuit, the entire ELS 115 kV subsytem will be islanded. Restoration procedure from this configuration already exists and documented in the SCO. Long outage times in the Chapleau sub-region have been raised through stakeholder feedback. The IESO coordinated an investigation into the matter with Working Group members and the transmitter has confirmed that there are refurbishment and component replacement plans in place for this sub-region which could alleviate this concern. The Working Group will continue to monitor the progress of these plans.

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Powering Tomorrow.

Appendix E

Regional Infrastructure Plan

East Lake Superior

REGIONAL INFRASTRUCTURE PLAN

October 1st, 2021

hydro one

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Prepared and supported by:

Company
Hydro One Sault Ste. Marie LP. (Lead Transmitter)
Hydro One Networks Inc. (Transmission)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Distribution)
Algoma Power Inc.
Chapleau Public Utilities Corporation
PUC Distribution Inc.

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 identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated 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 Study Team.

Study Team 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.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE SAULT STE. MARIE LP WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE EAST LAKE SUPERIOR REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Algoma Power Inc. ("API")
- Chapleau Public Utilities Corporation ("Chapleau PUC")
- Hydro One Networks Inc. (Transmission)
- Hydro One Sault Ste. Marie LP. ("HOSSM")
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PUC Distribution Inc. ("PUC")

This RIP is the final phase of the second cycle of East Lake Superior (ELS) regional planning process, which follows the completion of the East Lake Superior Integrated Regional Resource Plan ("IRRP") in April 2021 and the East Lake Superior Region Needs Assessment ("NA") in June 2019. This RIP provides a consolidated summary of the needs and recommended plans for East Lake Superior Region over the planning horizon (1 – 20 years) based on available information.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects are underway or completed

- **End of life Wood Pole Replacements**: Multiple wood pole replacement projects were completed on a number of 115kV and 230kV circuits. These circuits consisted of wood pole structures that were assessed at being at their end of life and in need of replacements. The following circuits have their end of life wood pole structures replacement completed between 2014 to 2019:
    - No.2 and No.3 Algoma (completed in 2014)
    - Northern Ave 115kV circuit (completed in 2014)
    - No.1 Garshore (completed in 2015)
    - Hogg (completed in 2015)
    - P21G (completed in 2019)

- **Hwy 101 TS**: Installed a new control building completed with new protection relays, batteries, chargers, automatic transfer schemes and RTU to replace end of life components such as electro-mechanical relays and batteries. This project was completed and in-serviced in 2015.

- **Anjigami TS**: Performed electrical and civil upgrade, including the installation of a new 44kV breaker, redundant battery and chargers, and replacement of protection equipment and other end of life AC/DC system. It also includes ground grid improvements. This project was completed in 2017.

- **Echo River TS**: Improve transmission reliability with the installation of an additional 230/34.5kV 25MVA Transformer (T2) as an on-site spare. This project is underway with a targeted in-service date of 2023 Q2.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1. Recommended Plans in East Lake Superior Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate(1)
1	Eliminate/Minimize manual communication between IESO and OGCC when arming Third Line Instantaneous Load Rejection Scheme	Enable remote arming of Third Line Instantaneous Load Rejection Scheme via ICCP line between IESO's EMS and HONI's NMS	2021	$10K
2	Third line TS: End of life protection	Replace end of life protection per current standard	2022	$0.8M
3	Echo River TS : Transmission Supply Reliability and end of life breaker	Install 'hot' spare transformer and replace end of life breaker	2023/2024	$11.5M
4	115kV Sault No.3: end of life structures and conductor	Replace end of life structure and conductor per current standard[1]	2024	$54.4M
5	Batchawana TS: End of life components	Refurbish Batchawana TS with MUS provision	2024	$6.2M
6	Goulais TS: End of life components	Refurbish Goulais TS with MUS provision	2024	$13.4M
7	Patrick St. TS, Algoma No.1 overload	Implement Automatic Load Rejection Scheme at Patrick St. TS	2023	$1.2M

[1] To coordinated with IESO's 2021 Bulk Planning Study regarding Sault No.3 Circuit Overloading

8	Patrick St. TS: End of life 115kV breaker	Replace end of life 115kV breakers ‘like for like’ per current standard	2024	$3.3M
9	Third Line TS : T2 end of life	Replace end of life T2 ‘like for like’ per current standard	2025	$16.4M
10	Northern Ave TS: end of life component replacement	Replace end of life T1 with smaller MVA unit and protection relays per current standard	2025	$2.5M
11	Anjigami/Hollingsworth TS : Transformer overload	Build new 115/44kV Station - HOSSM to work with API to continue to develop solutions	2024/2025	$30M
12	Clergue TS: End of life metal clad switch gear	Replace end of life switch gear ‘like for like’ per current standard	2026	$5.2M
13	Hollingsworth TS: End of life Protection relay	Replace end of life protection per current standard	2025	$1.1M
14	D.A. Watson TS: End of life metal clad switch gear	Replace end of life switch gear ‘like for like’ per current standard	2026	$9.2M

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

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1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN ("RIP") TO ADDRESS THE ELECTRICITY NEEDS OF THE EAST LAKE SUPERIOR REGION BETWEEN 2019 AND 2039.

The report was prepared by Hydro One Sault Ste. Marie LP (HOSSM) on behalf of the Study Team that consists of Hydro One Networks Inc. (Transmission), Hydro One (Distribution), Algoma Power Inc. (API), PUC Distribution Inc., Chapleau Public Utilities Corporation and the Independent Electricity System Operator ("IESO"), in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The East Lake Superior Region is the region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south as shown in Figure 1.1 below. The region is supplied from a combination of local generation and connection to the Ontario electricity grid via 230 kV transmission lines to Mississagi Transformer Station in the East, 230kV and 115 kV transmission lines to Wawa Transformer Station in the North.

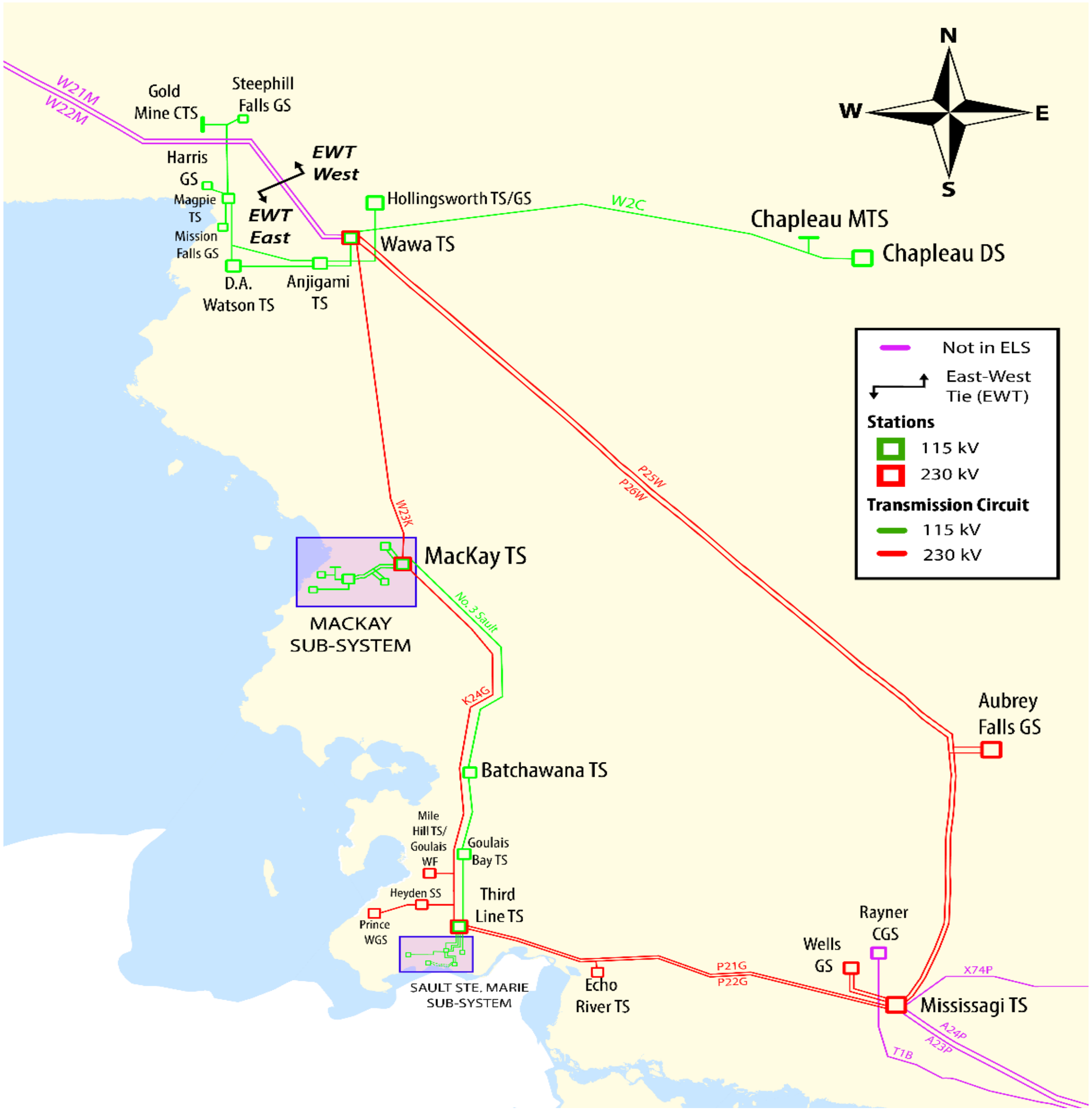

Figure 1-1: East Lake Superior Region Map

1.1 Objectives and Scope

The RIP report examines the needs in the East Lake Superior Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and
- 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 issues emerging over the near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, 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 the relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

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 regional characteristics.
- 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 adequacy of the transmission facilities in the region over the study period.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- 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 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 ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment[2] ("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 Study Team 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(s) ("LDC") or customer(s) and develops a Local Plan ("LP") to address them.

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 (CDM and Distributed Generation and energy efficiency) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase 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 a preferred wires solution. Similarly, resource options that 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, Indigenous communities, business sectors and other interested stakeholders in the region.

[2] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; 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 would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

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 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, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region;
- 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.

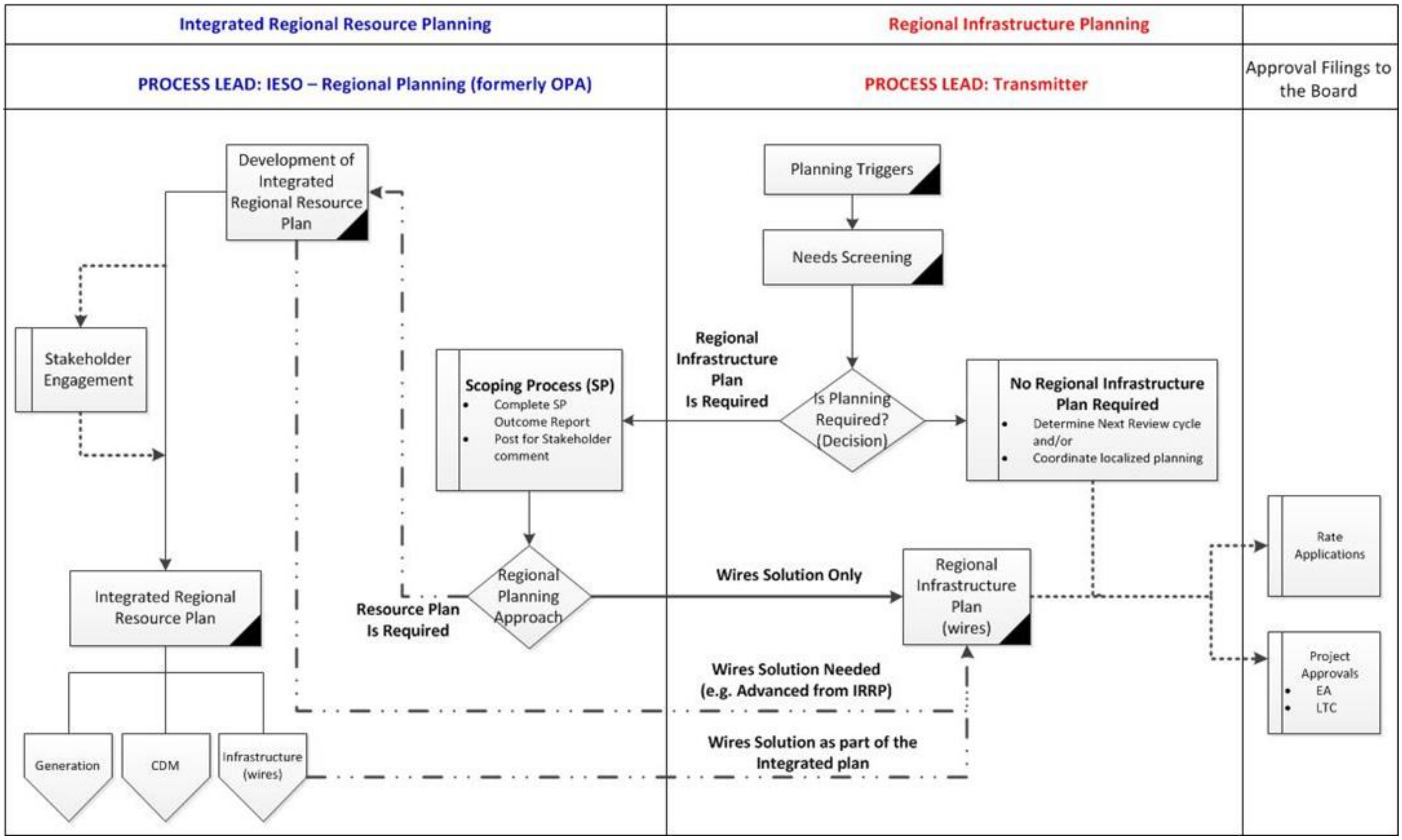

Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation 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. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required

or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

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.

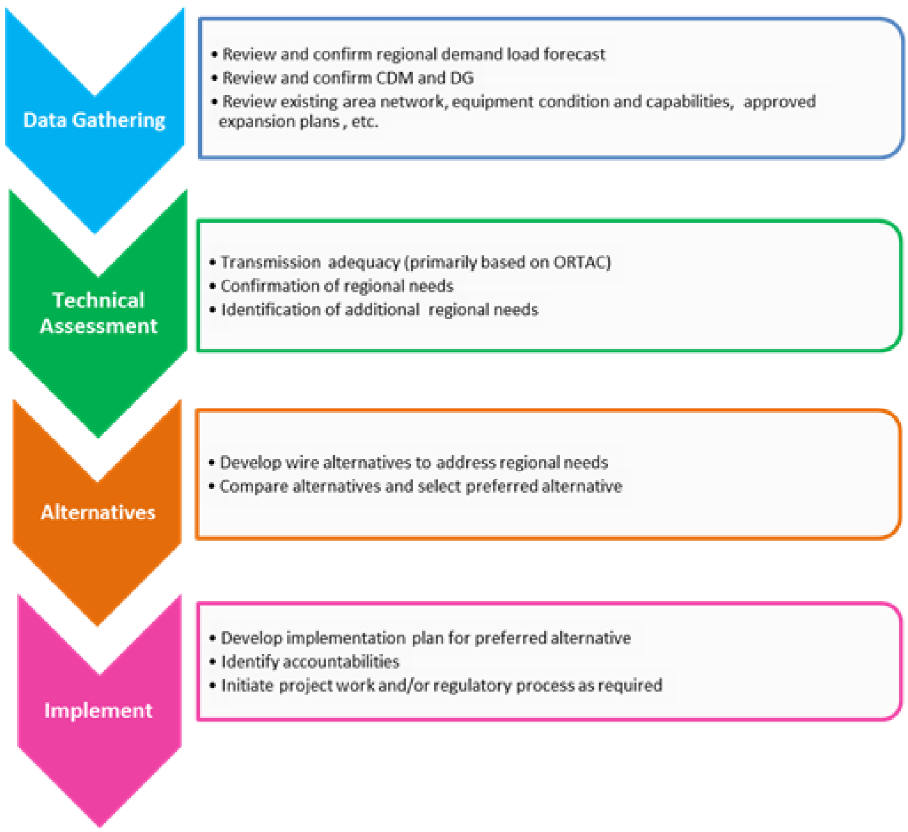

Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE EAST LAKE SUPERIOR REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY TOWN OF DUBERUILVILLE AND HIGHWAY 101 TO THE NORTH AND THE TOWNSHIP OF CHAPLEAU, BRUCE MINES TO THE SOUTH AND INCLUDES THE CITY OF SAULT STE. MARIE, HIGHWAY 129 TO THE EAST, AND LAKE SUPERIOR TO THE WEST. IT CONSISTS OF THE CITY OF SAULT STE. MARIE.

The region is supplied from a combination of local generation and connections to the Ontario electricity grid via 230 kV transmission lines to Mississagi Transformer Station in the East, 230kV and 115 kV transmission lines to Wawa Transformer Station in the North. Majority of the region's electrical need is supplied through a 230/115 kV transformer station at Third Line TS. Local generation in the area consists of mainly hydroelectric and wind generation with a total installed capacity of 1039 MW in the 115 kV and 230kV networks. The East Lake Superior Region is a winter peaking region, with 2020 winter peak demand at 361MW.

PUC Distribution Inc. ("PUC") is the Local Distribution Company ("LDC") which serves the electricity demand in the City of Sault Ste. Marie. The LDC that supplies primarily rural customers – industrial, commercial, and residential customers in the aregion are API, Chapleau PUC and Hydro One Networks Inc. Distribution

Below is a description of major Transmission asset in the region:

- Third line TS is the major transmission station that connects the 115kV system within the City of Sault Ste. Marie via two 230/115kV autotransformer to the 230kV bulk electricity network.
- Mackay TS is a 230/115kV station with one 230/115kV autotransformer that connects the local 115kV network in the vicinity of Montreal River to the 230kV bulk electricity network.
- Wawa TS is a 230/115kV station with two 230/115kV autotransformer that connects the local 115kV network in the vicinity of Michipicoten River.
- 12 other Transmission stations supply the area, with 10 of them operating at 115kV, 1 operating at 230kV , 1 operating at 44kV [3]
- A total of 319 km of 230kV circuits, 232 km of 115kV circuits and 10 km of 44kV circuits interconnect transmission stations, generation customer(s), distribution customer(s) and Transmission connected load customer(s) within the region.

Table in Appendix A and B summarize Transmission station and circuits at different operating voltages and in the area. A geographical map showing the electrical facilities of the East Lake Superior Region is provided in Figure 3-1. A single line diagram showing the electrical facilities of the East Lake Superior Region is provided in Figure 3-2.

[3] The 44kV station and line is included in HOSSM's transmitter license and are deemed transmission asset by the OEB.

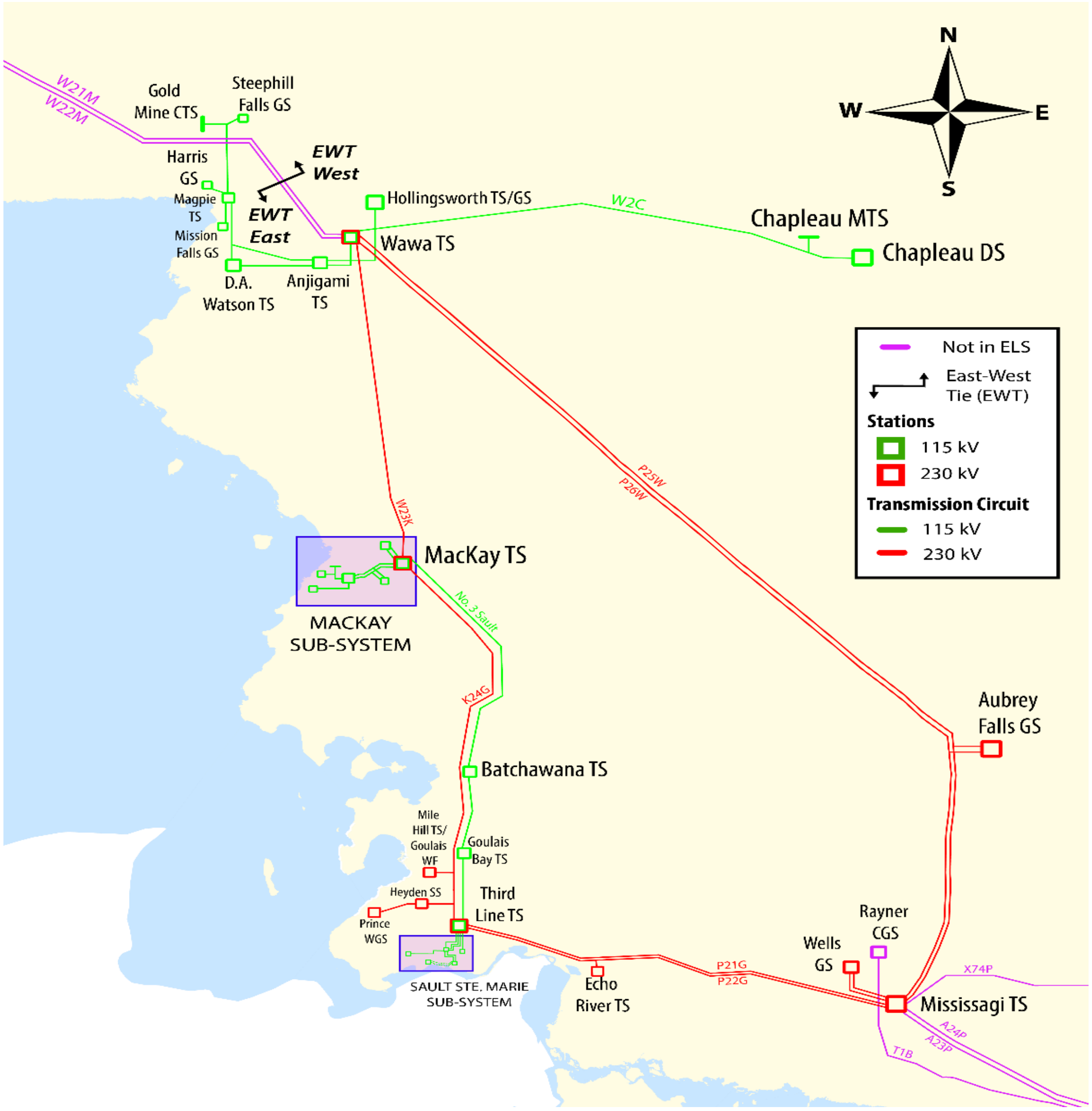

Figure 3-1: East Lake Superior Region's Transmission Network

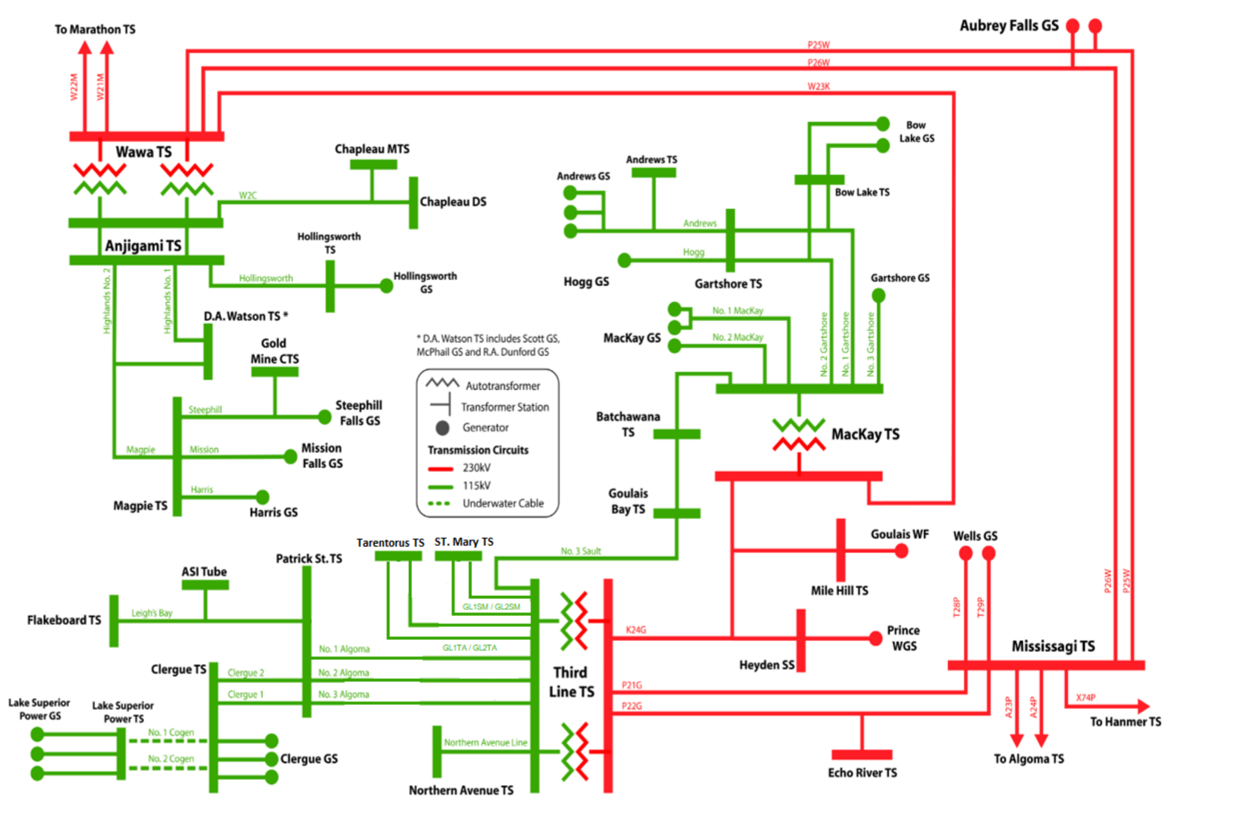

Figure 3-2: Single Line Diagram of East Lake Superior Region's Transmission Network

4 TRANSMISSION FACILITIES/PROJECTS COMPLETED AND/OR UNDERWAY SINCE LAST REGIONAL PLANNING

THE ESL REGIONS COMPLETED IT 1ST CYCLE REGIONAL PLANNING IN 2014. SINCE THAT TIME, SEVERAL \TRANSMISSION PROJECTS HAVE BEEN PLANNED AND/OR UNDERTAKEN BY HYDRO ONE SAULT STE. MARIE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE EAST LAKE SUPERIOR REGION.

A summary and description of the major projects completed and/or currently underway since the completion of last cycle regional planning is provided below.

- **End of life Wood Pole Replacements**: Multiple wood pole replacement projects were completed on a number of 115kV and 230kV circuits. These circuits consisted of wood pole structures that were assessed at being at their end of life and in need of replacements. The following circuits have their end of life wood pole structures replacement completed between 2013 to 2019:
    - No.2 and No.3 Algoma (completed in 2014)
    - Northern Ave (completed in 2014)
    - No.1 Garshore (completed in 2015)
    - Hogg (completed in 2015)
    - P21G (completed in 2019)

- **Hwy 101 TS**: Installed a new control building completed with new protection relays, batteries, chargers, automatic transfer schemes and RTU to replace end of life components such as electro-mechanical relays and batteries. This project was completed and in-serviced in 2015.

- **Anjigami TS**: Performed electrical and civil upgrade, including the installation of a new 44kV breaker, redundant battery and chargers, and replacement of protection equipment and other end of life AC/DC system. It also includes ground grid improvements. This is completed in 2017.

- **Echo River TS**: Improve transmission reliability with the installation of an additional 230/34.5kV 25MVA Transformer (T2) as an on-site spare. This project is underway and have a targeted in-service date of 2023 Q2.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The LDCs provided load forecasts for all the stations supplying their loads in the East Lake Superior region for the 20-year study period during the IESO led IRRP phase of regional planning. The net extreme weather corrected winter load forecast was produced by modifying the LDC forecast provided for each station to reflect extreme weather conditions and subtracted the estimated peak demand impacts of provincial conservation policy and committed Distributed Energy Resource (DER) that may have been contracted through previous provincial programs such as the Feed-in Tariff (FIT) and micro FIT program.

The electricity demand in the East Lake Superior Region is anticipated to stay flat over the next 20 years, with a peak of 348W in 2031. Figure 5-1 shows the East Lake Superior Region's Winter peak net load forecast developed during the East Lake Superior IRRP process. This IRRP forecast was used to determine the loading that would be seen by transmission lines and autotransformer stations and to identify the need for additional line and auto-transformation capacity. The IRRP non-coincident load forecasts for the individual stations in the East Lake Superior Region is given in Appendix D, Table D-1 and Table D-2. This forecast does not included a high industrial growth or expansion scenario, which will be studied as part of the IESO's bulk planning study in 2021 given the impact to the bulk transmission network in the broader region

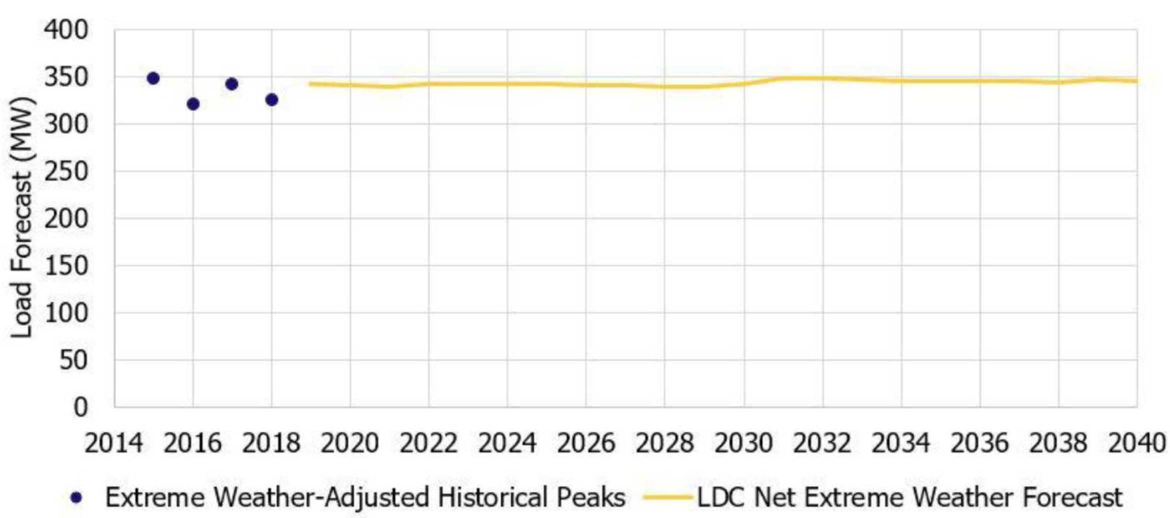

Figure 5-1: East Lake Superior Region Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2038.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.

- Winter is the critical period with respect to line and transformer loadings. The assessment is therefore based on winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks. Normal planning supply capacity for transformer stations is determined by the winter 10-day Limited Time Rating (LTR).
- Autotransformers and line capacity adequacy is assessed by using coincident peak loads in the area or supplied station(s). Where a circuit is feeding radial load, the capacity adequacy is assessed by using the connected station's non-coincident peak.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- The East-West Tie Transmission Reinforcement is included in the assessment.
- Hydro-electric generation assumption is taken as the output that is coincident with the region's overall 98% dependable output. Wind generation assumption were modelled by IESO based on their summer and winter capacity contribution factors per IESO Reliability Outlook, multiplied by their peak capacity.
- Sault No.3 circuit will be refurbished and return to network configuration at 115kV.

6 ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION LINE AND TRANSFORMER STATION FACILITIES SUPPLYING THE EAST LAKE SUPERIOR REGION OVER THE PLANNING PERIOD (2019-2038). ALL PROJECTS CURRENTLY UNDERWAY ARE ASSUMED IN-SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the East Lake Superior Region. The findings of these studies are input to this Regional Infrastructure Plan. The studies are:

- 2019 East Lake Superior Region Needs Assessment (“NA”) Report
- 2019 East Lake Superior Region Scoping Assessment (“SA”) Report
- 2021 East Lake Superior Integrated Regional Resource Plan (“IRRP”) and Appendices

This section provides a review of the adequacy of the transmission lines and stations in the East Lake Superior Region. The adequacy is assessed from a loading perspective using the latest regional load forecast provided in Appendix D. Sustainment aspects were identified in the NA report and are addressed in Section 7 of this report. The review assumes that the following projects shown in Table 6-1 will be in-service. Sections 6.1 to 6.4 present the results of this review.

Table 6-1: New Facilities Assumed In-Service

Facility	In-Service Date
‘hot’ spare transformer at Echo River TS	2023
115kV Sault No.3 circuit re-conductoring	2024

6.1 230 kV Transmission Facilities

The East Lake Superior 230 kV transmission facilities consist of the following 230 kV transmission circuits (please refer to Figure 3-1 and 3-2):

a) Mississagi TS to Third Line TS 230 kV circuits: P21G and P22G
b) Mississagi TS to Wawa TS 230 kV circuit: P25W and P26W
c) Wawa TS to Mackay TS 230 kV circuits: W23K
d) Mackay TS to Third Line 230 kV circuits: K24G

230kV circuits supplying the region are within their thermal limits as per ORTAC over the study period for the loss of a single 230kV circuit in the region. Voltage concerns is observed when applying multiple contingencies on Bulk Electric System (BES) elements as per performance requirements set out in NERC TLP-001-4.

6.1.1 Voltage Concerns on following the loss of P21G and P22G

P21G and P22G are critical 230kV supply circuits that connects Third Line TS with Mississagi TS. A double circuit loss of P21G and P22G due to them being adjacent circuits on common towers, or the loss of either one circuit, followed by a contingency on the companion circuit would cause voltage decline in violation with ORTAC voltage change limits (i.e., in excess of 10%) at Third Line TS and other 115kV facilities supplied from Third Line TS throughout the planning horizon. Loss of both P21G and P22G will also result in the loss of Third Line autotransformer T1 by configuration. IESO's IRRP has determined that the voltage instability threshold for the region is reached when the GLP inflow interface exceed 230MW and both P21G and P22G are out of service.

Third line TS is equipped with Instantaneous Load Rejection Scheme with six load blocks to be armed for the loss of P21G and P22G, or the loss of T1 and T2. Currently, the IESO will direct HOSSM to arm this scheme via Hydro One's Ontario Grid Control Centre (OGCC) using manual phone call, where IESO will request arming of certain amount of load for rejection depending on prevailing system conditions. HOSSM will prioritize selection of available load blocks. IESO has expressed the need to enable remote arming of this scheme directly from IESO control room to make the arming procedure more efficient. Section 7 will discuss in more detail.

6.2 230/115 kV Autotransformers Facilities

The 230/115 kV autotransformers facilities in the region consist of the following elements:

a. Third Line TS 230/115 kV, 150/200/250MVA autotransformers: T1, T2
b. Mackay TS 230/115 kV, 150/200/250MVA autotransformers: T2

Loading of Third Line TS autotransformers has been identified to approach their 10-day LTR when the companion autotransformer is lost. Loading on companion autotransformer during single event contingency (N-1) would be reduced modestly beyond 2024 when the Sault No.3 circuit returns to a network at 115kV (non-radial configuration).

This is not a firm need as there is no existing violations but this is flagged because loading on Third Line autotransformers is approaching its LTR limit and should continue to be monitored. Despite the fact that one of the autotransformer (T2) has been identified for end-of-life replacement by 2025, such replacement would only marginally improve supply capacity by 10MVA for Third Line's autotransformers due to LTR rating of the existing autotransformer (T1), which was put into service since 2007 and is not near End-of-Life.

6.3 115 kV Transmission Facilities

115kV circuits supplying the region are within their thermal limits as per ORTAC over the study period for the loss of a single transmission element in the region. A list of circuits can be found in Appendix B. Capacity overload is observed on 115kV circuit Algoma No.1 and Sault No.3 following multiple contingencies as per performance requirements set out in NERC TLP-001-4.

6.3.1 Capacity overload on 115kV circuit Algoma No.1

A failure of breaker 214 to operate at Patrick St TS will remove Algoma No.2 and Algoma No. 3 circuits from Third Line TS to Patrick St TS by configuration. This results in thermal overload of the remaining Algoma No. 1 circuit beyond its short-term emergency (STE) rating during peak loads at Patrick St TS, of which Algoma No. 1 is the lowest rated circuit out of the three. This thermal overload on Algoma No. 1 can also occur with one of the Algoma circuits initially out of service, followed by the loss of another Algoma circuit.

This is an existing issue which was also identified in the NA and SA report. This is currently mitigated by the Patrick St TS manual load shedding scheme under which load is curtailed manually at Patrick St TS following the loss of one of the Algoma line circuits. This is done to prevent overloading of the Algoma No. 1 circuit in case the second circuit is also lost. Since this scheme is manual, load has to be shed before the actual contingency of the second circuit has taken place. This scheme was designed as an interim solution until a more permanent solution was implemented. The IRRP has recommended a need for a more permanent solution.

6.3.2 Capacity overload of 115kV circuit Sault No.3

During an outage to either P25W or P26W circuit between Wawa TS to Mississagi TS, a contingency on the K24G circuit between Third Line TS and Mackay TS results in the thermal overload of the Sault No.3 circuit beyond its STE ratings starting in 2023 when No.3 Sault circuit is connected in a network configuration[4]. This phenomenon is a result of high East West Transfer (EWT) flows and losing two circuits that carry that flow. [5]

In addition, when one of the Third Line TS autotransformers is out of service, a Sault No.3 circuit operated as network configuration (after its proposed upgrades) helps to alleviate overloading of the companion Third Line TS autotransformer. However, if the second autotransformer is also lost, Sault No.3 circuit will be overloaded beyond its STE rating and causes a significant voltage decline in the 115kV area served by Third Line TS. The risk of capacity overload on Sault No.3 circuit and area voltage decline as a result of losing both autotransformer is presently mitigated by Third line's Instantaneous Load Rejection scheme. Subjected to the outcome of IESO's 2021 Bulk Planning Study with regards to Sault No.3 overloading, the overloading may continue to be a need.

6.4 Step-Down Transformer Station Facilities

There are a total of 11 step-down transformers stations in the East Lake Superior Region, connected to the 230 kV and 115 kV transmission network as listed below. The stations winter peak load forecast is given in Appendix D.

Table 6-2: East Lake Superior Step-Down Transformer Stations

230 kV Connected	115 kV Connected	
Echo River TS	Andrew TS	Chapleau MTS

[4] Sault No.3 circuit is currently operated radial to Mackay GS (G3) and is being refurbished as part of a sustainment project

[5] EWT is defined as the MW flow at Wawa TS on circuits W21M and W22M. By 2023, EWT tie flow will also include the flow of the new NextBridge circuits.

	Anjigami TS	Goulais TS
	Batchawana TS	Hollingsworth TS
	Clergue TS	Northern Ave TS
	Chapleau DS	St Mary CTS
	Tarentorus CTS	

Capacity of Anjigami T1 / Hollingsworth T1 & T2 are exceeded by end of 2024 based on the load forecast provided by LDC, where Hollingsworth T1 & T2 will be overload when Anjigami T1 is out of service, and vice versa. The overload is caused by loading increases on the 44kV circuit that Anjigami TS and Hollingsworth TS supply in parallel. HOSSM is working with the impacted LDC and have proposed to build a new 115/44kV station, with a proposed name Limer TS (subject to change) that will tap off Hollingsworth 115kV circuit to handle the load increase.

6.5 Bulk Areas Need

There is a potential for significant growth in industrial load in the ELS region over the planning period which would have a material impact on the bulk transmission system outside the region. Hence, the IESO has initiated a bulk planning study for this scenario outside of the regional planning process.

Based on the reference load forecast included in the IRRP, the following bulk system need was identified and will be further coordinated with the bulk planning study described above:

- Following the loss of one of the 230 KV circuits, P25W or P26W circuits from Mississagi TS to Wawa TS, the companion circuit becomes loaded beyond its LTR rating under high westward power flow on the EWT.

Results and recommendations from the bulk planning study would be published separately. HOSSM and HONI will work with IESO to address recommendations as appropriate.

7 REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE EAST LAKE SUPERIOR REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses electrical infrastructure needs in the East Lake Superior Region and plans to address these needs. The electrical infrastructure needs encompass both end of life replacement needs identified in the Need Assessment phase, and needs identified in section 6. A list of needs are summarized below in Table 7.1.

Table 7-1: Identified Near and Mid-Term Needs in East Lake Superior Region

Section	Facilities/Circuit	Need	Timing
7.1	Third Line TS/OGCC	Enable remote arming of Third Line TS Instantaneous Load Rejection Scheme	Immediate
7.2	Third Line TS	End of life Protection replacement	2022
7.3	Patrick St TS, Algoma No.1 overload	Automate existing manual load curtailment scheme to meet NERC standards	Immediate
7.4	Echo River TS	Transmission Supply Reliability / End of Life 230kV Breaker replacement	2023/2024
7.5	115kV Sault No.3	Sault No.3 Structure and End of Life Conductor Replacement[6]	2024
7.6	Batchawana TS and Goulais TS	End of Life component replacement	2024
7.7	Patrick St TS	End of Life 115kV breaker replacement	2024
7.8	Third Line TS	T2 End of Life Replacement	2025
7.9	Northern Ave TS	T1 End of Life replacement	2025

[6] To coordinated with IESO's 2021 Bulk Planning Study Regarding Sault No.3 Circuit Overloading

7.10	Anjigami/Hollingsworth TS	Anjigami/Hollingsworth Transformers Overload	2024
7.11	Clergue TS	End of life metal clad switch gear replacement	2026
7.12	Hollingsworth TS	End of life Protection replacement	2026
7.13	Watson TS	End of life metal clad switch gear replacement	2026

7.1 Third Line TS – Enable remote arming of Third Line TS Instantaneous Load Rejection Scheme.

7.1.1 Description

Instantaneous Load Rejection Scheme at Third line TS are designed to respond to the loss of both P21G and P22G, or the loss of both T1 and T2. This scheme is currently armed under the direction of IESO. Upon IESO request, OGCC will manually arm the scheme and prioritized available load blocks for rejection. OGCC has established communication channels to perform arming function via Hydro One Network Management System (NMS).

7.1.2 Alternatives and Recommendation

The following alternatives were considered to address Main TS end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it will not address the manual process involved in arming of the load rejection scheme, as well as the selection of load blocks to be armed. The risk of communication delays between IESO and OGCC is not mitigated.

2. **Alternative 2 – Enable remote arming of Third Line TS Instantaneous Load rejection scheme:** Under this alternative, Hydro One will work with IESO to make necessary control points available on IESO's Energy Management System (EMS) interface such that IESO's control command can be relayed to OGCC's NMS via existing Inter-Control Centre Communication Protocol (ICCP) link, which will subsequently be relayed to Third Line's Instantaneous Load Rejection Scheme.

The Study Team recommends Alternative 2 as the technically preferred and most cost-effective alternative because this will facilitate the automation of dispatch arming from IESO in a real-time setting, and eliminate manual communications delays between IESO and Hydro One. Further, given the ICCP infrastructure already exists, the cost to perform alternative 2 is expect to be limited to control points and status points set up in NMS and EMS respectively, as well as testing activities that can be done in both ends to ensure functionality. The estimated cost for this upgrade is about $10,000 and is expected to in-service by end of 2021.

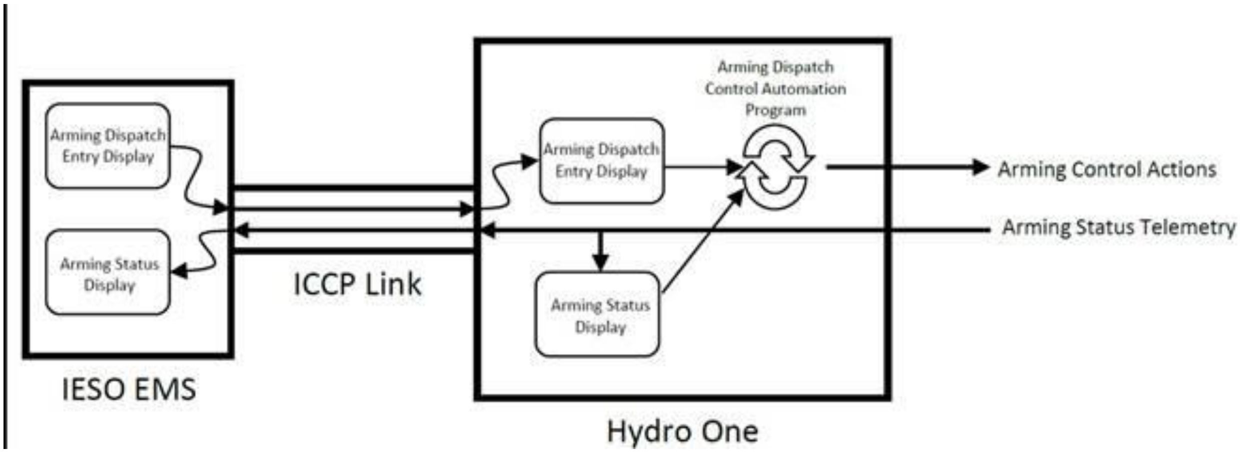

Figure 7-1: ICCP link between IESO and Hydro One.

7.2 Third Line TS – End of life Protection Replacement

7.2.1 Description

Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Third line TS 115kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, No.3 Sault circuit and Northern Ave circuit. It also supplies two (2) LDC HV load supply stations via 115kV circuits GL1SM GL2SM, GL1TA, and GL2TA. Based on an asset condition assessment, P21G's and P22G's line protections are approaching end of life. Further, due to legacy reasons, P21G's and P22G's line protection do not meet standard physical separation requirement .

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to end-of-life asset condition and would result in increased maintenance expenses and reduce supply reliability to the ELS region.

2. **Alternative 2 – Replace end-of-life protection as per current standard:** Under this alternative the existing end-of-life protection will be replaced with new protection relay consistent with Hydro One standard. This alternative will also implement 'A' and 'B' protection separation, which will

bring these protection be in compliance with reliability standards, addresses the end-of-life assets need, minimizes losses and maintains reliable supply to the customers in the area.

The Study Team recommends Alternative 2 – replace end-of-life protection relay. The protection replacement work is expected to be complete by 2022.

7.3 Patrick St TS – Automatic Load Rejection Scheme

7.3.1 Description

Patrick St TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2 and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No .1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area. Based on IESO IRRP findings, upon a breaker failure of breaker 214, or a contingency on either Algoma No.2 or Algoma No.3 circuit, followed by another contingency on the remaining circuit, Algoma No.1 will be overloaded beyond its STE rating during peak load. At present, a manual load shedding scheme is implemented as an interim solution until a more permanent solution is available.

7.3.2 Alternatives and Recommendation

The following alternatives were considered to address the interim manual load shedding scheme need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of circuit overload during contingency and could result in equipment (overhead conductor) damage, increase public safety risk and reduce supply reliability to connected customers.

2. **Alternative 2 – Implement Automatic Load Rejection Scheme at Patrick St TS:** This alternative would implement an automatic load rejection upon the loss of Algoma No.2 and Algoma No.3 to reject load blocks and respect the existing LTE rating of Algoma No.1 circuit.

Considering above options, the Study Team recommends that Hydro One proceed with Alternative 2, consistent with recommendation from the ELS's IRRP.

7.4 Echo River TS – Install Spare 230kV Transformer (2023) and end of life 230kV breaker replacement (2024)

7.4.1 Description

Echo River TS is a 230kV load supply station. The station consists of a single 230/115/34.5kV autotransformer and a single 230kV circuit breaker (556) to supply two (2) 34.5 kV customer feeders. Historically, load at Echo River TS can be transferred to Northern Ave TS 34.5 kV feeders via the API's distribution system in case of outages at Echo River TS, such as transformer maintenance or failure.

As per the 2nd cycle of Need Assessment completed in Q2 2019 for the ELS region, it has been identified that the existing back up from Northern Ave TS can no longer provide adequate voltage support at peak load during a transformer outage at Echo River TS.

Echo River 230kV breaker 556 is a live tank minimum oil breaker, which has also been identified to be end of life and obsoleted based on asset condition assessment.

7.4.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address system reliability needs and HOSSM asset needs due to asset condition. This alternative would result in increased maintenance expenses and reduce supply reliability to the customers.

2. **Alternative 2 – "Cold" spare 230kV Transformer and replace end of life 230kV breaker :** install a "cold" spare in Echo River TS that is completed with new spill containment only, without 230kV and 34.5kV connection facilities and dedicated protection equipment. The spare will not normally put on potential. This alternative is not recommended as the load restoration time associated with connecting the unit and making it ready to serve load would exceed ORTAC load restoration requirement.

3. **Alternative 3 – "Hot" spare 230kV Transformer and replace end of life 230kV breaker:** install a "hot" spare in Echo River TS that is completed with new 230kV and 34.5kV connection facilities, dedicated protection equipment and new spill containment systems. The spare transformer is usually on potential and ready to serve load upon switching. This alternative can significantly shorten load restoration time to respect ORTAC load restoration timeline in the event of a transformer outage due to maintenance or failure, which improves local transmission supply reliability.

The Study Team recommends Alternative 3 – "Hot" spare 230kV Transformer and replace end of life 230kV breaker. The spare transformer is planned to be completed by 2023, while the breaker replacement work is planned to be completed in 2024. In lieu of replacing the breaker HOSSM will install a 230 kV circuit switcher and enable transfer trip functionality between Echo River TS and it's terminal stations.

7.5 115kV Sault No.3 Structure and Conductor Replacement

7.5.1 Description

Built in 1929, Sault No.3 is a 90 km long 115kV transmission circuit that runs from MacKay TS 115kV station yard to Third Line TS 115kV station yard. This circuit provides an alternative path for local generation to reach load centres close to the Sault Ste. Marie area. Based on asset condition assessment, approximately 70km of the circuit's conductor from Goulais TS (str # 129) to MacKay TS is the original conductor, and has been rated between "Poor" and "Very Poor" as it has multiple component (sleeves) failures. This circuit also accounts for 39% of all line equipment related outages experienced over the 2013 – 2017 period within HOSSM's sytem. The circuit is currently de-rated as a pre-cautionary action to minimize further stress. Due to the de-rating, Sault No.3 circuit is also forced to operate in a radial configuration to Mackay G3 to limit loading on the line. The end of life replacement work would include 'like for standard' conductor replacement and replacement of selected wood poles along the corridor as condition warrants.

HOSSM has completed the detail project defitnition work for this project. It is noted that the on-going IESO bulk system studies have considered upgrading Sault 3 to 230kV[7] as a potential solution. IESO bulk system studies is expected to be available Q4 2021. Provided that IESO's recommendation is to refurbish the line as per current plan, the project is expected to be completed by 2024.

7.5.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition. Failure of this circuit can impact the power supply to load centres close to the city of Sault Ste. Marie.

2. **Alternative 2 - Replace conductor, structures and associated End-of-Life components with Hydr One standard 115kV equipment:** Under this alternative, the existing conductor and wood pole that are assessed to be end of life will be replaced with new 115 kV rated line and structures. This alternative will also allow Sault No.3 to return to its network configuration.

The Study Team recommends Alternative 2 – the replacement of the end-of-life conductor and wood pole structures between Mackay TS and Goulais TS (str # 129) as it addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

7.6 Batchawana TS and Goulais – End of life Component Replacement

7.6.1 Description

Batchawana TS and Goulais Bay TS are load supply stations with single transformer to supply to the Batchawana Bay and Goulais Bay areas. Goulais Bay TS is about 30 km North of Sault Ste. Marie, while Batchawana TS is about 47 km North of Sault Ste. Marie along Hwy 17. Both are connected to 115kV No.3 Sault circuit. Figure 7-2 below shows geographical location of both station. Based on asset condition assessment, both stations are at End-of-life stage with obsoleted equipment including power transformers, protections (fuse), batteries, chargers, steel structure foundations and remote terminal units. Both stations are also built with legacy design standards and do not provide adequate clearance to today's standard. Their single transformer configuration has also made it difficult to schedule and perform maintenance.

[7] Possibly upgrading to 230kV standard and operate at 115kV until 230kV operation is needed for the bulk system.

Figure 7-2: Batchawana TS and Goulais Bay TS on 115kV circuit

7.6.2 Alternatives and Recommendation

A detailed assessment that analyzed supply options for Batchawana TS and Goulais Bay TS was carried out between HOSSM and API from 2019 -2020 to compare and evaluate supply options based on Transmission and Distribution supply reliability and performances. The assessment compared three (3) different options, they are:

- Option 1: Refurbish both Goulais Bay TS and Batchawana TS using a new 115kV, 3 –phase power transformer, with provision for a 115kV Mobile Unit substation (MUS) connection facility in each station. Transformer capacity to be sized to handle the long term peak forecast of the individual stations.

- Option 2: Consolidate Goulais Bay TS and Batchawana TS into a 'New' TS that is equipped with two 20MVA, 3-phase transformer to supply both distribution sub-system at either 12.5kV or 25kV. The location of this 'New' TS would be in the vicinity of Goulais bay.

- Option 3: Consolidate Goulais Bay TS and Batchawana TS into a 'New' TS with dedicated 25kV "express feeder" between Goulais and Batchawana. This 'New' TS would be located in the vicinity of Goulais bay, and be equipped with two 20MVA, 3-phase transformer to supply both distribution sub-system at either 12.5kV or 25kV. An additional 25/12.5kV unit is required on the distribution system in the vicinity of Batchawana bay to convert voltage from the incoming 25kV dedicated "express feeder" to 12.5kV in order to supply distribution sub-system in the vicinity of Batchawana bay.

Depending on the choice of distribution voltage, there are two (2) different scenarios (12.5kV vs 25kV) for each option above. Evaluation of alternatives was completed by HOSSM and API as documented in the 2021 East Lake Superior Regional Local Planning Report. As per the report's recommendation, HOSSM is proceeding with option 1 - Refurbish both Goulais Bay TS and Batchawana TS. More details related to the supply option analysis can be found in the Local Planning Report – Supply Option Analysis for Goulais and Batchawana (2020), available on Hydro One public website. Refurbishment for both stations are expected to be completed in 2024.

7.7 Patrick St TS – End of life 115kV breaker replacement

7.7.1 Description

Patrick St TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2 and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No .1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area. Based on asset condition assessment, breaker 208, 211, 214 and 217 are minimum oil live tank breakers that are considered End of Life and obsolete.

7.7.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability for customers.

2. **Alternative 2 - Replace the end-of-life breakers with new standard breakers:** This alternative involves the replacement of breaker 208, 211, 214 and 217 with new SF6 breakers in similar ratings.. This alternative is recommended as it addresses the end-of-life asset needs and maintains reliable supply to customers connected at Patrick St TS by reducing the risk of breaker failure; and reducing on-going maintenance cost associated with obsolete breaker technology.

Alternative 2 is recommended. The project is expected to be completed by 2024.

7.8 Third Line TS – T2 End of Life Replacement

7.8.1 Description

Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Third line TS 115kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, No.3 Sault circuit and Northern Ave circuit. It also supplies two (2) PUC HV load supply stations via 115kV circuits GL1SM GL2SM, GL1TA, and GL2TA. Among the 2 autotransformers, T2 is at end of life based on asset condition assessment. Based on long term load forecast, units with similar ratings are required for the end of life autotransformer T2 replacement.

7.8.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the region.

2. **Alternative 2 – Replace T2 with equivalent size unit as per current standard:** This alternative would replace old T2 with a unit that has equivalent rating. This is recommended alternative as it will mitigate risk of autotransformer failure due to its deteriorating conditions and maintain supply reliability of the region.

3. **Alternative 3 – Replace T2 with larger size unit:** This alternative would replace old T2 with a unit that has higher rating. This alternative is rejected as a 230/115kV autotransformer at 150/200/250MVA is currently the highest rating available based on HOSSM and Hydro One standards.

Alternative 2 is recommended. The project is expected to be completed by 2025.

7.9 Northern Ave TS – T1 End of Life Replacement

Northern Ave TS is a 115kV load supply station that is connected to Third Line TS via 115kV Northern Ave circuit. Northern Ave Transformer T1 is a 115/34.5kV, 20/26.7MVA step down transformer that supplies Algoma Power Inc. via one (1) 34.5kV feeder. Transformer T1 is at end of life. Historically, Northern Ave TS has been used as a backup supply to Echo River TS to facilitate outages. Reliance on Northern Ave TS is expected to reduce starting 2023 as the spare unit at Echo River TS comes into service in 2023. The longer term forecast for Northern Ave TS peaks at 2.7MW.

7.9.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace T1 with a smaller MVA size unit as per current standard:** This alternative would replace T1 with a 'like for similar' unit that has a smaller MVA rating compared to existing T1, and would be adequate for Northern Ave's long term load forecast. This is recommended alternative as it will mitigate risk of transformer failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2025.

7.10 Anjigami/Hollingsworth TS – Transformer overload.

Anjigami TS is a 115kV/44kV load supply station with a single transformer. Hollingsworth TS is a 115kV/12.5kV/44kV station that supplies load on 44kV, and connected to Hollingsworth CGS on the 12.5kV. Anjigami's and Hollingsworth's 44kV feeders are connected to each other with a 10km long 44kV line to supply LDC load on No.4 circuit. Base on LDC load forecast, load increase on 44kV system by end of 2024 would exceed transformer capacity in both Anjigami TS and Hollingsworth TS when the companion station is out of service. HOSSM is working with API and have proposed to build a new 115/44kV station, with a proposed name Limer TS (subject to change) that will tap off Hollingsworth 115kV circuit to handle the load increase.

7.10.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the transformer capacity needs based on load forecast.

2. **Alternative 2 – Replace Anjigami T1, Hollingsworth T1 and T2 with a larger MVA size units as per current standard to handle load increases:** This alternative is considered but not recommended as both Anjigami TS and Hollingsworth TS have a limited footprint, and site expansion would be required for both sites for such upgrade. Further, due to Hollingsworth TS existing configuration, upgrades are also required on all existing 12.5kV facilities, including disconnect switches, breakers, and overhead bus work to accommodate the load increase.

3. **Alternative 3 – Build new 115/44kV 'Limer TS' that will be supplied from Hollingsworth 115kV circuit, transfer existing LDC load from existing 44kV system to 'Limer TS' :** This alternative would build a new 115/44kV station in the vicinity of Hollingsworth TS and tap off from 115kV Hollingsworth circuit to supply new loads as well as existing load that are presently supplied by Anjigami/Hollingsworth 44kV system. The new station would be similar to a DESN station with two (2) 115/44kV, 50/67/83MVA transformers as per current HONI standard, HV

and LV connection facilities such as circuit switchers and feeder breakers, modern protections and telecommunication systems to service the new load. API will re-route their 44kV feeder(s) and connect to 'Limer TS'.

Given the alternatives above, Alternative 3 is recommended because it is expected to be the most cost efficient alternatives. Compared to Alternative 2, where it will require the coordination of 2 environmental approvals at different sites for site expansion, replacement of three (3) transformer (Anjigami T1, Hollingsworth T1 and T2), and upgrade on existing 12.5kV equipment at Hollingsworth TS, Alternative 3 has a more concise scope. Building new station will also have less outage constraints when compared to upgrading existing facilities. HOSSM will continue to work with API to develop a local solution. The project is expected to be completed by end of 2024/early 2025.

7.11 Clergue TS - End of life metal clad switch gear replacement

Clergue TS is a 115kV station that connects Clergue Generating Station and LSP co-generation station to the HOSSM system via two (2) 115kV circuits emanating from Patrick St TS. Based on an asset condition assessment, the existing 12 kV minimum-oil metal-clad switchgear is at End-of-Life and obsoleted

Based on the load forecast and expected system conditions, similar equipment ratings are required for end of life replacement.

7.11.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace existing metal clad switch gear with SF6 metal clad switch gear as per current standard:** This alternative would replace existing minimal oil metal clad switch gear with SF6 metal clad switch gear. This is recommended alternative as it will mitigate risk of switch gear failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2026.

7.12 Hollingsworth TS – End of life Protection Replacement

Hollingsworth TS is a 115kV station that connects Hollingsworth Generating Station and is supplied by Hollingsworth 115kV circuit. Majority of protection relay equipment in Hollingsworth TS were in-serviced 2005. Based on asset condition assessment, the existing protection relay would approach end of life by 2025.

7.12.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace end of life protection with "like for like" protection relay as per current standard:** This alternative would replace identified end of life protection relays with as per current standard. This is recommended alternative as it will mitigate risk of protection relay failure due to their deteriorating conditions and maintain supply reliability to connected customers.

Alternative 2 is recommended. The project is expected to be completed by 2025

7.13 Watson TS - End of life Metal Clad switch gear replacement

DA Watson TS is a 115kV load supply station that also has connectivity with three (3) local hydro generating stations. The station has two 45/60/75 MVA transformers and nine 34.5kV feeders using metal clad switch gear. Based on an asset condition assessment, the existing minimal oil metalclad switch gear are at End of life and obsolete

7.13.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace existing metal clad switch gear with SF6 metal clad switch gear as per current standard:** This alternative would replace existing minimal oil metal clad switch gear with SF6 metal clad switch gear. This is recommended alternative as it will mitigate risk of equipment failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2026.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE EAST LAKE SUPERIOR REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in East Lake Superior Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Eliminate/Minimize manual communication between IESO and OGCC when arming Third Line Instantaneous Load Rejection Scheme	Enable remote arming of Third Line Instantaneous Load Rejection Scheme via ICCP line between IESO's EMS and HONI's NMS	2021	$10K
2	Third line TS: End of life Protection	Replace end of life protection per current standard	2022	$0.8M
3	Echo River TS : Transmission Supply Reliability and end of life breaker	Install 'hot' spare transformer and replace end of life breaker	2023/2024	$11.5M
4	115kV Sault No.3: end of life structures and conductor	Replace end of life structure and conductor per current standard[8]	2024	$54.4M
5	Batchawana TS: End of life components	Refurbish Batchawana TS with MUS provision	2024	$6.2M
6	Goulais TS: End of life components	Refurbish Goulais TS with MUS provision	2024	$13.4M
7	Patrick St. TS, Algoma No.1 overload	Implement Automatic Load Rejection Scheme at Patrick St. TS	2023	$1.2M
8	Patrick St. TS: End of life 115kV breaker	Replace end of life 115kV breakers	2024	$3.3M
9	Third Line TS : T2 end of life	Replace end of life T2	2025	$16.4M
10	Northern Ave TS: end of life component replacement	Replace end of life T1 with smaller MVA unit and protection relays per current standard	2025	$2.5M
11	Anjigami/Hollingsworth TS : Transformer overload	Build new 115/44kV Station - HOSSM to work with API to continue to develop solutions	2024/2025	$30M

[8] To coordinated with IESO's 2021 Bulk Planning Study Regarding Sault No.3 Circuit Overloading

12	Clergue TS: End of life metal clad switch gear	Replace end of life switch	2026	$5.2M
13	Hollingsworth TS: End of life Protection relay	Replace end of life protections	2025	$1.1M
14	D.A. Watson TS: End of life metal clad switch gear	Replace end of life switch gear	2026	$9.2M

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 8-1 while keeping the Study Team apprised of project status;
- Any other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

9 REFERENCES

[1] East Lake Superior Region Needs Assessment (2019)

[2] East Lake Superior Region Scoping Assessment (2019)

[3] Local Planning Report – Supply Option Analysis for Goulais and Batchawana (2020)

[4] East Lake Superior Integrated Regional Resource Plan (2021)

[5] East Lake Superior Integrated Regional Resource Plan - Appendices (2021)

APPENDIX A. STATIONS IN THE EAST LAKE SUPERIOR REGION

Station	Voltage (kV)	Supply Circuits
Andrews TS	115/25	Andrew 115kV
Anjigami TS	115/44	High falls No.1 /Highfalls No.2
Batchawana TS	115/12.5	Sault No.3
Chapleau DS	115/25	W2C
Chapleau MTS	115kV	W2C
Clergue TS	115/12.5	Clergue No.1 / Clergue No.2
D.A. Watson TS	115/34.5	Magpie 115kV/High falls No.1 /Highfalls No.2
Echo River TS	230/34.5	P22G
Flakeboard CTS	115	Leigh's Bay 115kV
Gartshore SS	115	Gartshore No.1 / Gartshore No.2/ Gartshore No.3 / Hogg 115kV / Andrews 115kV
Gold Mine CTS (Magnacon Mine)	115	Steephill 115kV
Goulais Bay TS	115/12.5	Sault No.3
Heyden CSS	230	K24G
Hollingsworth TS	115/12.5/44	Hollingsworth 115kV
Hwy 101 SS	44	Anjigami 44kV/Limer 44kV
Mackay TS	230	K24G/W23K
Mackay TS	115	Gartshore No.1 / Gartshore No.2/ Mackay No.1/Mackay No.2/Sault No.3
Magpie SS	115	Harris 115kV/Steephill 115kV /Mission Falls 115kV/Magpie 115kV
Mile Hill CTS	230	K24G
Northern Ave. TS	115/34.5/12.5	Northern Ave 115kV
Patrick St. TS	115/34.5	Algoma No.1/No.2/No.3 , Clergue No.1 /No.2
St Mary CTS	115/34.5	GL1SM / GL2SM
Tarentorus CTS	115/34.5	GL1TA / GL2TA
Third Line TS	230	K24G/P21G/P22G
Third Line TS	115	Sault No.3, Algoma No.1/No.2/No.3, Northern Ave 115kV
Wallace Terrace CTS	115/34.5	Leigh's Bay 115kV

Wawa TS	230	P25W/P26W/W21M/W22M/W35M*/W36M*
Wawa TS	115	W2C/ Hollingsworth 115kV

*after the completion of East West Tie

APPENDIX B. TRANSMISSION LINES IN THE EAST LAKE SUPERIOR REGION

Location	Circuit Designations	Voltage (kV)
Mississagi x Third line	P21G , P22G	230
Mississagi x Wawa	P25W, P26W	230
Third line x Mackay	K24G	230
Mackay x Wawa	W23K	230
Third line x Mackay	Sault No.3	115
Third line x Patrick St.	Algoma No.1 / No.2 / No.3	115
Third line x Norther Ave	Northern Ave 115kV	115
Third line x St Mary CTS	GL1SM, GL2SM	115
Third line x Tarentorus CTS	GL1TA , GL1TA	115
Patrick st x Flakeboard CTS	Leigh's Bay 115kV	115
Patrick St. x Clergue TS	Clergue No.1 / No.2	115
Mackay GS x Mackay TS	Mackay No.1 / No.2	115
Gartshore SS x Mackay TS	Gartshore No.1 / No.2	115
Gartshore SS x Hogg CGS	Hogg 115kV	115
Gartshore SS x Andrew CGS	Andrew 115kV	115
Magpie SS x Mission Falls CGS	Mission falls 115kV	115
Magpie SS x Steephill CGS	Steephill 115kV	115
Magpie SS x Harris CGS	Harris 115kV	115
Magpie SS x DA Watson TS	Magpie 115kV	115
DA Watson TS x Wawa TS	High Falls No.1/No.2	115
Hollingsworth TS x Wawa TS	Hollingsworth 115kV	115

Anjigami TS x Hwy 101 SS	Anjigami 44kV	44
Hollingsworth TS x Hwy 101 SS	Limer 44kV	44

APPENDIX C. DISTRIBUTORS IN THE EAST LAKE SUPERIOR REGION

Distributor Name	**Station Name**	**Connection Type**
Algoma Power Inc.	Andrew TS	Tx
	Anjigami TS	Tx
	Batchawana TS	Tx
	D.A. Watson TS	Tx
	Echo River TS	Tx
	Goulais TS	Tx
	Mackay TS (115kV)	Tx
	Northern Ave TS	Tx
	Hollingsworth TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Chapleau PUC	Chapleau MTS	Tx
Hydro One Networks Inc. (Dx)	Chapleau DS	Dx
PUC Distribution	St Mary CTS	Tx
	Tarentorus CTS	Tx

APPENDIX D. EAST LAKE SUPERIOR REGION LOAD FORECAST

Table D-1: East Lake Superior Non-coincident peak Load Forecast, with the Impacts of Energy-Efficiency Savings per station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	1.56	1.85	1.86	1.88	1.90	1.91	1.93	1.95	1.97	1.98	2.00	2.02	2.04	2.05	2.06	2.08	2.10	2.12	2.14	2.15
DA Watson TS	8.53	8.57	8.55	8.56	8.57	8.58	8.60	8.63	8.67	8.71	8.75	8.80	8.87	8.93	8.99	9.06	9.13	9.20	9.26	9.32
Echo River TS	14.18	14.23	14.19	14.19	14.17	14.18	14.20	14.23	14.28	14.33	14.38	14.45	14.57	14.67	14.80	14.95	15.06	15.17	15.25	15.33
Goulais Bay TS	8.00	8.00	9.49	9.81	10.40	10.70	10.76	10.83	10.90	10.96	11.01	11.07	11.13	11.18	11.23	11.29	11.36	11.43	11.50	11.57
Limer TS	13.18	13.74	13.81	13.88	13.99	54.00	54.00	28.62	28.65	28.68	28.70	28.76	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00
Andrews TS	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Mackay TS	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Northern Av TS	2.50	2.51	2.50	2.51	2.51	2.51	2.52	2.53	2.54	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.67	2.70	2.71	2.73
Chapleau DS	6.31	6.47	6.51	9.24	9.32	9.38	9.44	9.51	9.59	9.68	9.76	9.84	9.94	10.03	10.13	10.23	10.33	10.44	10.53	10.63
Chapleau MTS	4.47	4.36	4.44	4.19	4.69	4.58	4.59	4.59	4.21	4.15	4.14	4.27	4.27	4.27	4.27	4.28	4.29	4.29	4.29	4.30
PUC Distribution Inc.	120.7	119.5	117.5	115.9	114.2	112.7	111.4	110.0	108.9	107.9	106.8	109.7	116.5	115.7	114.9	114.2	113.6	112.9	112.3	111.5

Table D-2: East Lake Superior Forecasted Impacts of Energy-Efficiency Savings due to Codes , Standards and Funded CDM Program

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
DA Watson TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Echo River TS	0.11	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.24	0.27	0.30	0.32	0.33	0.34	0.34	0.34
Goulais Bay TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Limer TS	0.11	0.19	0.19	0.19	0.15	0.15	0.15	0.15	0.15	0.15	0.17	0.19	0.23	0.25	0.28	0.30	0.32	0.32	0.32	0.32
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.02	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.06	0.06	0.06	0.06
Chapleau DS	0.07	0.12	0.12	0.12	0.10	0.10	0.10	0.10	0.10	0.10	0.12	0.13	0.16	0.18	0.20	0.22	0.23	0.23	0.23	0.23
Chapleau MTS	0.03	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.06	0.07	0.07	0.08	0.09	0.09	0.09	0.09	0.09
St. Mary's TS	0.91	1.58	1.54	1.54	1.16	1.16	1.13	1.12	1.12	1.08	1.17	1.29	1.46	1.60	1.76	1.87	1.93	1.91	1.88	1.86
Tarentorus TS	1.16	2.02	1.97	1.98	1.49	1.48	1.45	1.43	1.43	1.39	1.50	1.66	1.88	2.05	2.25	2.40	2.47	2.44	2.41	2.38
Total	**2.56**	**4.45**	**4.36**	**4.39**	**3.33**	**3.32**	**3.27**	**3.23**	**3.23**	**3.15**	**3.45**	**3.84**	**4.39**	**4.82**	**5.32**	**5.69**	**5.87**	**5.84**	**5.79**	**5.74**

Table D-3: East Lake Superior IRRP Forecasted DER by station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DA Watson TS	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Echo River TS	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.16	0.12	0.08	0.02	0.01	0.00	0.00	0.00
Goulais Bay TS	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Limer TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau DS	2.65	2.65	2.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau MTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
St. Mary's TS	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	0.23	0.18	0.16	0.16	0.16	0.14	0.00	0.00
Tarentorus TS	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	0.14	0.10	0.06	0.03	0.03	0.02	0.00	0.00	0.00

Appendix F

Renewable Energy Generation Plan Submitted to the IESO

Engineering Department
500 Second Line East, P.O. Box 9000
Sault Ste. Marie, Ontario, P6A 6P2
Phone: (705) 759-6576
Email: eng-dept@ssmpuc.com

ECRA/ESA Lic. # 7001626

October 26, 2021

Independent Electrical System Operator
120 Adelaide Street West, Suite 1600,
Toronto, ON, M5H 1T1

Re: Renewable Energy Generation Plan for PUC Distribution Inc.
Request to IESO for comment Letter

Dear Sir/Madame:

PUC Distribution Inc. (PUC) is presently preparing its 2023 Cost of Service Rate Application as well as finalizing its 2023-2027 Distribution System Plan (DSP) for submittal to the Ontario Energy Board (OEB). In accordance with the OEB's Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements we are hereby respectfully requesting the IESO provide a "Letter of Comment" with respect to our Renewable Energy Generation (REG) plans which you will find attached.

PUC would greatly appreciate receiving the IESO's Letter of Comment at the earliest opportunity as PUC will need to incorporate the feedback received into their DSP.

We trust this letter and submittal is adequate and clear for your use in the intended purpose but should there be any associated questions or comments, kindly direct them to the undersigned.

Regards,

M Paradis

Mitchell Paradis, P.Eng
Protection and Control Engineer
705-759-6585
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PUC Services Inc.
500 Second Line East, P.O. Box 9000
Sault Ste. Marie, ON, P6B 4K1

Renewable Energy Generation Plan

PUC Distribution Inc.

2021-10-26

Executive Summary

PUC Distribution Inc. (PUC) is a Local Distribution Company (LDC) licensed to distribute electricity in its service territory which includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. PUC serves approximately 33,500 customers, hosts 63MW of Renewable Energy Generation (REG) and 7MW/7MWh of energy storage infrastructure.

PUC has prepared this document summarizing how it takes the connection of REG projects into account in its planning. It also serves to demonstrate how compliance is achieved with associated regulatory requirements as described in the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements. In broad summary that document identifies that LDCs must have long term plans that address REG and that, with respect to those plans that they shall:

- Identify all applications received for REG connections
- Provide a forecast of anticipated future REG connections
- Identify the available system capacity to connect REG projects
- Discuss how any system constraints impact REG connection
- Discuss how any constraints affect any embedded distributors.

In Section 1 the quantity and size (MW) of current REG applications to PUC are identified. At present there are none.

A forecast for REG connections is provided in Section 2. PUC is anticipating the connection of one 250kW generator per year for a total connection of 1.25MW over the next 5 year period.

Section 3 covers how distribution system capacity is evaluated and provides a tabulated view of present available capacities on the main feeders and buses throughout the system. Adequate capacity is available to connect all forecast REG projects between 2023 and 2027.

Potential constraints and barriers to REG are considered in Section 4. Operational flexibility, protection, control and SCADA systems, how PUC participates in local and regional planning and PUCs REG objectives and strategies are all given consideration. Generally it is concluded that growth of REG on the PUC grid will not be constrained by any internal or regional factors.

Section 5 briefly states that there are no REG impacts to Embedded Distributors since none are connected to the PUC distribution system.

Section 6 concludes the report with a five year plan and investment strategy. It states that, the PUC grid is presently very well positioned to support all forecast REG connections over the next five years and no associated infrastructure investment is required during that period.

Contents

1 Applications for REG Connections

Activity with REG connections was significant prior to 2011 for PUC (61MW) but dropped off sharply thereafter with 1MW of interest in the five-year period between 2012 and 2017 and 0.09MW thereafter from 2018 through October 2021 as further detailed below.

1.1 Applications for REG Greater than 10kW

For REG generator connections greater than 10 kW, there are presently no applications to PUC. The connection history for all REG installations connected to the PUC distribution system over 10kW is illustrated in the table below. Of all the applications made, those that were not connected had applications terminated by the applicant and in no cases was unavailable capacity the deciding factor.

PUC Applications from Renewable Generators Over 10kW

	Application Date		Application MW		Connection Date		Connection MW	
Pre-2013	1985		0.25		1985		0.25	
	2008-01-08		0.037		2008-07-08		0.037	
	2007-07-24		0.045		2008		0.045	
	2007-04-15		9.95		2010-10-15		9.96	
	2007-04-17		9.95		2010-10-15		9.96	
	2007-06-03		9.95		2011-08-30		9.96	
	2007-06-03		9.95		2011-08-30		9.96	
	2007-06-03		9.95		2011-07-27		9.96	
	2007-06-03		9.95		2011-11-22		9.96	
	2007		9.95		N/A		0	
	2007		9.95		N/A		0	
	2011-09-09		0.035		2012-11-23		0.035	
	2011-06-07		0.5		2011-07-20		0.5	
	2011-09-26		0.25		2012-08-29		0.25	
	2011-02-28		0.1		2011-06-09		0.1	
	2011-06-14		0.135		2011-11-14		0.135	
	Quantity	16	Total MW	80.952	Quantity	14	Total MW	61.112
2013	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2014	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2015	2015-02-18		0.1		2016-08-23		0.1	
	Quantity	1	Total MW	0.1	Quantity	1	Total MW	0.1
2016	2016-06-23		0.07		2016-09-20		0.07	
	2016-03-11		0.25		2017-01-06		0.25	
	2016-03-11		0.25		2017-01-06		0.25	
	2016-03-11		0.25		2017-01-06		0.25	
	Quantity	4	Total MW	0.82	Quantity	4	Total MW	0.82
2017	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2018	2018-11-23		0.087		N/A		0	
	Quantity	1	Total MW	0.087	Quantity	1	Total MW	0
2019	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2020	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2021	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2017-2021 Totals	Quantity	1	Total MW	0.087	Quantity	1	Total MW	0
Grand Total	Quantity	17	Total MW	81.039	Quantity	15	Total MW	61.112

Table 1 - Applications for REG Over 10kW

1.2 Applications for REG 10kW or less

Currently there are no applications in the queue from REG connections <10kW. Since the wind-down of the Micro-FIT program by the province, there appears to be a growing interest in net metering and some discussions about that in conjunction with energy storage behind the meter, however this has not materialized into any significant connected projects. There have been a total of six net metering <10kW connections totaling 41kW since 2016 and there are currently two connection applications totaling 14kW in progress for 2021.

2 Forecast REG Connections

2.1 Local Planning and Stakeholder Engagement

PUC interacts with the City of Sault Ste. Marie administration 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 widening projects can be planned. PUC staff attends formal meetings with the City and other municipal stakeholders and local utilities, annually, to review budgets and work plans for the coming year and the coming 5 years. Other ‘ad hoc’ coordination sessions occur on an ‘as needed’ basis with the stakeholders to look for synergies on specific projects and initiatives.

The annual coordination meetings are generally initiated by the City’s administration and PUC along with other utilities that participate in them. For large commercial developments PUC participates in Development Assistance Review Team (DART) meetings on a regular basis for all large developments early in the planning stage. Additionally, PUC is included and invited to comment on all rezoning, severance and building applications allowing PUC to identify requirements early in the development stage. Inclusion in these processes assists PUC in understanding where and when projected developments will proceed and allows them to plan and size their infrastructure appropriately. Although detailed information about the upcoming projects is not always available five years in advance these consultations do provide qualitative indication of the volume of anticipated projects involving new customer connections, subdivision developments and line relocates. These meeting often offer at least some glimpse into potential for future REG projects and Smart Grid developments. At present there are no discussions indicating any REG projects are being proposed.

2.2 Five Year 2018-2022 REG Forecast

PUC has produced a 5 year forecast of future REG connections >10kW. For the period 2023-2027 projections have been based on:

- local economic and population data
- macro-economic conditions
- awareness of information from IESO and OEB regarding connection rates and programs
- historical uptake and connection frequency

Based on those factors, the five year forecast in Table 2 below has been established with an anticipated connection of one 100kW generator every second year for a total connection of 0.3MW over the next 5 year period.

	Projected # of Connections	Installed MW
2023	1	0.1
2024	0	0
2025	1	0.1
2026	0	0
2027	1	0.1
2023-2027 Totals	3	0.3

Table 2 - Forecast REG for 2023-2027

3 System Capacity to Support REG

3.1 System Description

The distribution network owned and operated by PUC includes:

(a) **34.5 kV sub-transmission network –** consisting of nine 34.5kV feeders supplied from two 115kV Transformer Stations TS1 and TS2. The 34.5kV network supplies a total of twelve 34.5/12.47kV stations, one 34.5/4.16kV station, and one 34.5/12.47&4.16kV station and a number of large industrial customers. Much of the 34.5kV network is connected in a looped type configuration affording a high degree of operating flexibility during contingencies. The 34.5kV network also provides connections to six ~ 10MW solar generation stations.

(b) **12.47 kV distribution network –** consisting of approximately 50 feeders supplied from twelve municipal stations. With the exception of two stations that have 2x7.5MVA transformer capacity, the remaining stations are equipped with 2x10MVA transformers. 336kcmil or 3/0AWG conductor size is typically employed on feeder trunk lines and the average length of the trunk section of 12.47kV feeders is approximately 10 km.

(c) **4.16 kV distribution network** – PUC has been gradually upgrading the 4.16kV network to 12.47kV, but there are still two 4.16kV stations in service supplying three feeders. The average length of the trunk section of the 4.16kV feeders is approximately 5km. A majority of the trunk lines employ a conductor size of 3/0AWG or 336kcmil. This infrastructure will be fully phased out and upgraded to 12.47kV by 2023.

3.2 Short Circuit Capacity

One consideration for the interconnection of REG projects to the distribution system is to determine the impact of introducing a new source of fault current. On a given feeder it is necessary to conduct a full review on the various system components such as conductors, insulators, switches, breakers and transformers to determine if there are any exceedances.

Through software based system modelling and engineering studies PUC Engineering has arrived at the conclusion that solar PV embedded generation has negligible system impact from this perspective. Typical solar panel inverter fault currents are in the order of 105% to 125% of the inverter nameplate and cease to generate fault current within 30ms.

On PUCs 34.5kV system, all equipment has withstand and interrupting ratings of 25kA or higher and typical pre-REG system fault levels are typically 19kA and lower. In connecting six 10MW facilities circa 2010-2011, connection impact assessments (CIAs) were completed and it was determined at that time that any connection scenario for inverter based DG that respected thermal circuit limits would inherently respect short circuit interrupting and withstand ratings for all equipment.

Similar observations have been made and conclusions drawn on the 12kV system where withstand and interrupting ratings are again 25kA but fault levels are most typically 11kA or less with the exception of Sub 19 which is closer to 17kA.

PUC has not yet been asked to connect any REG customers >10kW to the 4.16kV distribution system and it has not been reviewed comprehensively. However, in the majority of areas a 12kV circuit is almost always in place as an alternative and, where not, it would be possible to accelerate part of the voltage conversion program in short order to make a 12kV connection point available.

3.3 Thermal Capacity and Circuit Loading

All of PUCs 34.5kV circuits have a nominal rating of 600A and a thermal limit of approximately 35MVA/30MW. PUC has successfully studied and connected 20MW of solar generation on one 34.5kV feeder. Similar results would be expected on any of the remaining systems feeders as their characteristics are much the same.

A number of research projects undertaken by various organizations in Canada and USA have focused on the maximum allowable penetration levels of embedded generation from renewables that could be connected to distribution feeders without adverse impacts on reliability, power quality and stability. There is consensus among experts that distributed generation capacities up to the minimum feeder load levels during light load conditions generally have beneficial impacts on power quality and load flows. Most experts agree that solar power penetration rates of up to approximately 25%-30%, where penetration rate is defined as the AC output of Embedded Generating Plant divided by the Peak Load Capacity of Distribution System, do not result in adverse impacts on operating performance [Reference: High Penetration of Photovoltaic (PV) Systems into the Distribution Grid – Workshop Report" U.S. Department of Energy 2009].

PUCs 12.47kV circuits have a nominal rating of 300A(6.5MVA) with a target load operating range between 150A-200A(3.3-4.4MVA). Following the recommendations discussed above, a rule of thumb has been established that 1MW of solar PV can be safely integrated on a typical 12kV feeder although a case by case CIA is always required.

3.4 Available System Capacity

Primarily based on thermal ratings of conductors and transformers, PUC has developed and submitted to the IESO, the following table of available capacity. The IESO uses this for planning and as an input to preparing a Transmission Availability Table (TAT) which is posted online to assist prospective REG applicants in selecting a site for their project. Table 3 summarizes available capacity at the 34.5kV feeder and station bus levels. It can be seen that at present there is still capacity available for the future connection of approximately 27MW more generation between circuits out of TS1 and TS2 combined.

It is noted here that feeders SM-5, 7, 9 and 11 are shown as having only 3.7MW each of remaining capacity however those capacities are based on the limiting factor of the upstream 115kV/35kV transformers at TS1 which have a combined limit of 45MW. The limit of 45MW less the existing connected 41.3MW REG leaves the possibility of connecting a combined total of 3.7MW in any combination on those four feeders. So although each of the four feeders have 20MW of available thermal capacity, they are limited by the fact that the station transformer remaining capacity is lower. Based on the projected connections for the next five years, this does not represent a system constraint.

Station	Bus Name	Capacity (MW)	Allocated Capacity (MW)	Available Capacity (MW)	Supply Circuit 1	Supply Circuit 2
TS1	**Total**	**45**	**41.328**	**3.672**	**GL1SM**	**GL2SM**
(St. Mary's)	West	30	21.009	3.672		
	East	30	20.318	3.672		
TS2	**Total**	**45**	**21.663**	**23.337**	**GL1TA**	**GL2TA**
(Tarentorus)	West	30	21.015	8.985		
	East	30	0.647	23.337		

34.5 kV Feeder Name	Bus Connection	Capacity (MW)	Allocated Capacity	Available Capacity (MW)	Notes:
SM-5	West	30	10.214	3.672	TS Limiting (45-D5) MW
SM-7	West	30	9.960	3.672	TS Limiting (45-D5) MW
Sub 19 West	West	N/A	0.835	N/A	no feeder, direct bus connection
SM-9	East	30	10.034	3.672	TS Limiting (45-D5) MW
SM-11	East	30	10.034	3.672	TS Limiting (45-D5) MW
Sub 19 East	East	N/A	0.250	N/A	no feeder, direct bus connection
TS1			**41.328**		
TA-6	West	30	0.139	23.337	TS Limiting (45-D8) MW
TA-7	West	30	20.876	8.985	West Bus Limiting (30-D9) MW
TA-9	East	30	0.028	23.337	TS Limiting (45-D8) MW
TA-10	East	30	0.188	23.337	TS Limiting (45-D8) MW
TA-11	East	30	0.431	23.337	TS Limiting (45-D8) MW
TS2			**21.663**		

Table 3 - PUC Available Capacity

PUC's own operating experience indicates successful integration of approximately 63 MW of REG on its distribution system with winter peak demand of approximately 140 MW and summer as low as 80MW.

4 Constraints to REG Connections

4.1 PUC Distribution Inc. Long term Planning

Support for REG and smart grid is integral to the long term planning processes employed by PUC. In 2009 in response to enactment of the Green Energy Act, PUC Engineering identified a set of strategies that would support the REG/Smart Grid objectives of the Act while bringing value to its customers (see Figure 1 - Smart Grid and REG Objectives and Strategies). This set of strategies has served as a foundation for past capital investments, and the bulk of the strategies have been implemented to completion removing barriers to future REG investments.

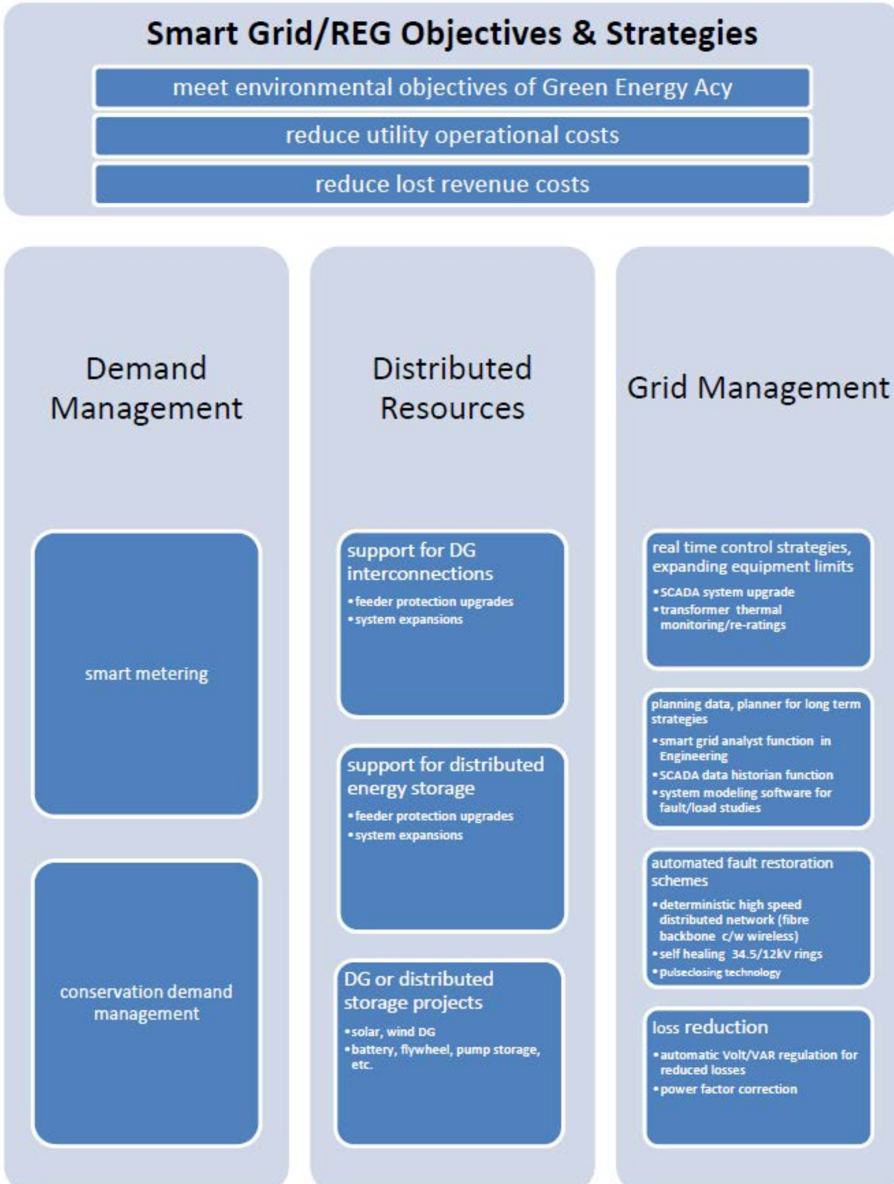

Figure 1 - Smart Grid and REG Objectives and Strategies

4.2 Operational Flexibility

Integration of REG has presented some new challenges to maintaining the operational flexibility previously afforded to PUC by a highly looped 34.5kV and 12.47kV system. However we continue to work closely with the generators during the development and connection agreement stages of each project to ensure that both the generator and the LDC find solutions that minimize limitations to operational flexibility.

4.3 Protection, Control, and SCADA

The introduction of REG resources introduces the potential for reverse power flow conditions, reduced relay sensitivity to trip during fault conditions, power quality and voltage regulation. Solutions to these problems call for fast and advanced modern microprocessor based and communications enabled protection, control and SCADA equipment. PUC anticipated these needs amongst others such as reliability and embarked on a number of initiatives over the past 10 years that will benefit REG and smart grid deployments now and in the future:

- A major upgrade of the PUC SCADA core components and implementation of a data historian (2008 – 2011)
- Deployment of an Ethernet based communications backbone over modern fibre-optic and radio platforms to support protection, control, SCADA, telemetry, metering, and enterprise network functions. Support for anticipated forthcoming NERC cybersecurity requirements is built in. (2010-2018)
- Upgrade of protective relaying at TS1, TS2 and all 12kV stations not slated for rebuilds or retirement in the next 5 years to microprocessor based, IP communications based equipment capable of full REG support (2008 – 2022)
- The Sault Smart Grid (SSG) Project is planned for 2021-2022 will bring Volt/VAR optimization to every 12.47kV feeder, as well as automated system restoration and fault isolation, and an upgraded SCADA/OMS system for in depth system analysis

4.4 Regional Infrastructure Planning

PUC belongs to the "East Lake Superior Region (ELS-Region)" planning team, for which former Great Lakes Power Transmission (GLPT), now Hydro One Networks is the lead transmitter and responsible party for steering the regional planning in this region.

In response to the OEB Regional Infrastructure Planning (RIP) process approved in 2013, development of an Integrated Regional Resource Plan (IRRP) was triggered by the IESO in April 2019 and will be completed in 2021. PUC participated in the planning process and provided required data to HONI and the IESO. The scope of this planning initiative was to identify critical infrastructure needs of the transmission grid during the next 20 years beginning in 2020. The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans. The results will be made available by the IESO when the ELS-Region IRRP is finalized.

The report shows a modest decline in load for the PUC over the study period and only nominal growth for the region. No constraints or barriers to REG growth for the PUC service territory are anticipated as a result of the regional factors considered.

5 Constraints to Embedded Distributors

PUC has no embedded distributors therefore does not contribute to any associated REG constraints.

6 Proposed Plan and Investments to Support REG

Due to the Sault Smart Grid (SSG) project and investments over the past 10 years primarily in protection, control, SCADA and communications infrastructure, PUC is well positioned to support a broad range of REG and smart grid initiatives. PUC can also say with confidence that past investments along with currently available capacity will allow the connection of all forecast REG projects for the next five years with no need for additional system investments.

Appendix G

IESO Comment Letter

IESO response to PUC Distribution Inc.'s REG Investments Plan 2023 – 2027

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricty System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan. On October 26, 2021, PUC Distribution Inc. (PUC) sent its REG Investments Plan to the IESO for comment. The IESO has reviewed PUC's REG Investments Plan and notes that it contains no investments specific to connecting REG for the plan period 2023 - 2027.

The IESO notes that PUC's service territory is within the East Lake Superior Region. The IESO confirms that PUC participated with the Study Team for this region.[1] The IESO reports that regional planning is complete in the East Lake Superior Region, with the publication of the Integrated Regional Resource Plan (IRRP) on April 1, 2021.[2]

The Needs Assessment for the East Lake Superior region was published by Hydro One Networks Inc. on June 14, 2019 indicating further regional planning was required for the region.[3] The IESO's Scoping Assessment Outcome Report outlining the planning approach for the region, and related Terms of Reference, was published on October 3, 2019. [4]

PUC's REG Investments Plan Section 6: Proposed Plan and Investments to Support REG states:

> *"Due to the Sault Smart Grid (SSG) project and investments over the past 10 years primarily in protection, control, SCADA and communications infrastructure, PUC is well positioned to support a broad range of REG and smart grid initiatives. PUC can also say with confidence that past investments along with currently available capacity will allow the connection of all forecast REG projects for the next five years with no need for additional system investments."*

The IESO submits that as PUC has no REG investments planned at this time nor forecast during the 5-year Distribution System Plan period, no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties.[5]

The IESO appreciates the opportunity provided to review the REG Investments Plan of PUC Distribution Inc. and looks forward to working together in future regional planning processes.

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[1] East Lake Superior Region Study Team members include the IESO and Hydro One Networks Inc. (Distribution and Lead Transmitter), PUC Distribution Inc., Algoma Power Inc. and Hydro One Sault Ste. Marie LP

[2] IESO, East Lake Superior Region IRRP, April 1, 2021: East Lake Superior (ieso.ca)

[3] Hydro One Networks Inc., East Lake Superior Needs Assessment, June 14, 2019: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/eastlakesuperior/Documents/Needs%20Assessment%20Report%20-%20East%20Lake%20Superior%20Region%20(2019-06).pdf

[4] IESO, East Lake Superior Region Scoping Assessment, October 3, 2019: East Lake Superior (ieso.ca)

[5] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

Appendix H

Asset Condition Assessment

METSCO

MAKING IT POSSIBLE

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ASSET CONDITION ASSESSMENT FINAL REPORT 2021

Prepared by

METSCO Report no. P-21-126-R1

May 2022

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Asset Condition Assessment Report 2021

Final Report

September 2021

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Date	**Rev.**	**Status**	**By**	**Checked**	**Approval**

Executive Summary

Context of the Study

PUC Distribution Inc. ("PUC") is an electricity distributor serving approximately 33,750 residential and commercial customers in the City of Sault Ste. Marie, the Batchewana First Nation (Rankin Reserve), Prince Township, and parts of Dennis Township. PUC operates a system made up of 15.5 km of overhead 115kV transmission, 99 km of 34.5-kV subtransmission, and 623 km of distribution lines and cables (12.47 kV and below). PUC also owns and operates assets at two Transmission Stations ("TS") and fourteen substations.

PUC engaged METSCO Energy Solutions Inc. ("METSCO") to prepare a comprehensive Asset Condition Assessment ("ACA") study for the assets comprising PUC's distribution system. The ACA is required as one of the key inputs for the preparation of PUC's five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements for electricity distributors enacted by the Ontario Energy Board ("OEB"). The scope of the ACA covers PUC-owned assets for all subtransmission and distribution lines/cables, fourteen substations, and two TS but does not cover the 115-kV transmission line assets. It is recommended to perform a separate study to assess the condition of the transmission lines.

Scope of the Study

METSCO's work included interviews with PUC subject matter experts to define the Health Indices ("HI") appropriate for the asset types, review and consolidation of the client's data sets, analysis of PUC's asset records to calculate the HI values, and preparation of the final document. In total METSCO assessed and calculated HI values for the following asset classes:

- Distribution Wood Poles
- Underground Primary Cables
- Distribution Transformers (Pole-mount, Pad-mount, or Submersible)
- Pad-mount Distribution Switchgear
- Underground Switches (Junction Boxes)
- Station Power Transformers
- Medium-Voltage Station Switchgear
- 34.5-kV TS Circuit Breakers
- Station Battery Banks and Chargers

- Station Building Facilities
- Station Riser Cables

For asset classes with not enough information to calculate HI, METSCO created age assessments to summarize the age profile of those asset classes. The following asset classes are included as part of age assessments but do not have calculated health indices:

- Distribution Steel Poles
- Overhead Primary Conductors
- Fused Disconnect Switches (Cut-outs)
- Load-Break Switches
- Station Service Transformers

All asset condition data used in the study is maintained by PUC as part of its regular asset management practices. The ACA results are based on condition data recorded by PUC and its contractors up to September 2021. This information was provided to METSCO between May and September 2021.

To supplement the information provided by PUC, METSCO conducted a site visit in August 2021 to assess the condition of PUC's TS and substations, focusing on power transformers, 34.5-kV TS circuit breakers, station buildings, and station fences. The site visit involved a visual inspection and infrared ("IR") scan. In addition, METSCO assessed the condition of PUC's medium-voltage switchgear, battery banks, and chargers based on photos and IR scans obtained by PUC.

Methodology and Findings

For all asset classes that underwent assessment, METSCO used a consistent scale of asset health from Very Good to Very Poor. The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table 0-1 presents the HI ranges corresponding to each condition score, along with their corresponding implications as to the follow-up actions required by the asset manager at PUC.

Table 0-1: Health Index Ranges and Corresponding Implications for the Asset Condition

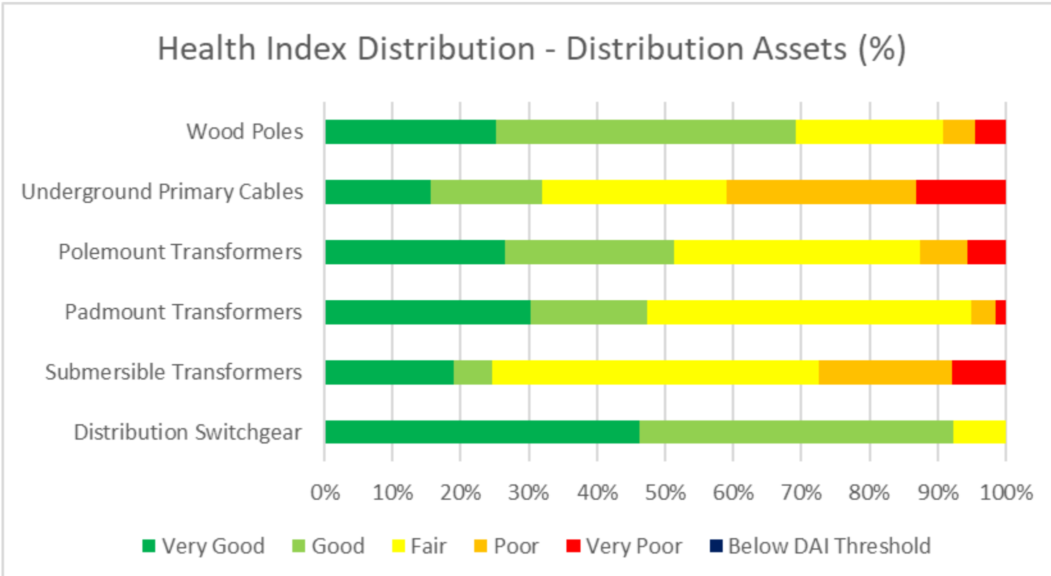
Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, METSCO calculated the HI for every asset in the scope of the assessment using the applicable and available "condition parameters" – individual characteristics of the state of an asset's components. Each condition parameter has its own sub-scale of assessment and a weighting contribution that represents the percentage in the overall HI made up by the parameter. METSCO's findings for each asset class were developed using this methodology, as described in more detail in Section 3 and Section 4.

The consolidated results of the ACA for distribution assets are summarized in

Figure 0-1. The HI is not calculated for any distribution asset with a Data Availability Indicator ("DAI") less than 70% (i.e., less than 70% of the condition parameters – by weight – are available for that asset) or less than 65% for station assets. The HI results for assets with a known HI were divided into ten-year bands and extrapolated to the unknown set within those bands.

Figure 0-1: Distribution Asset Health Index Results – Extrapolated

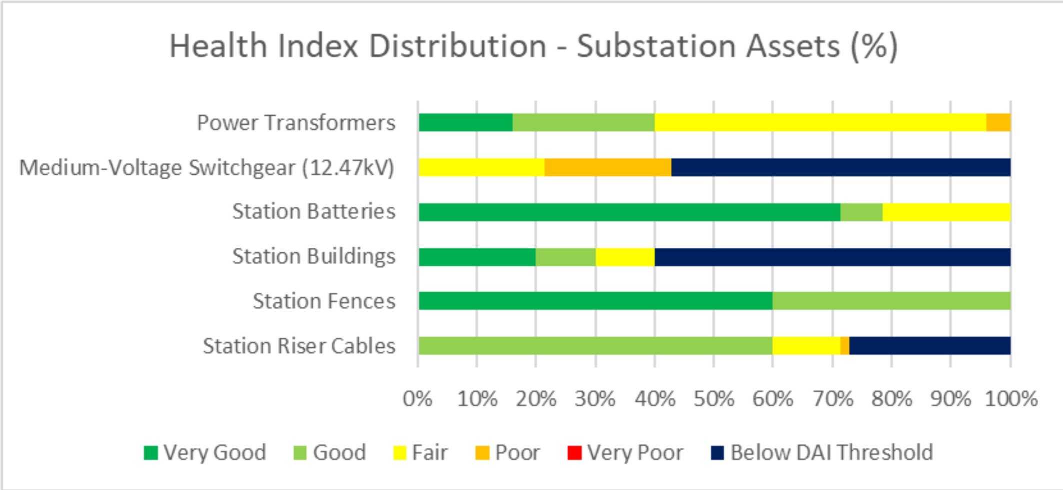


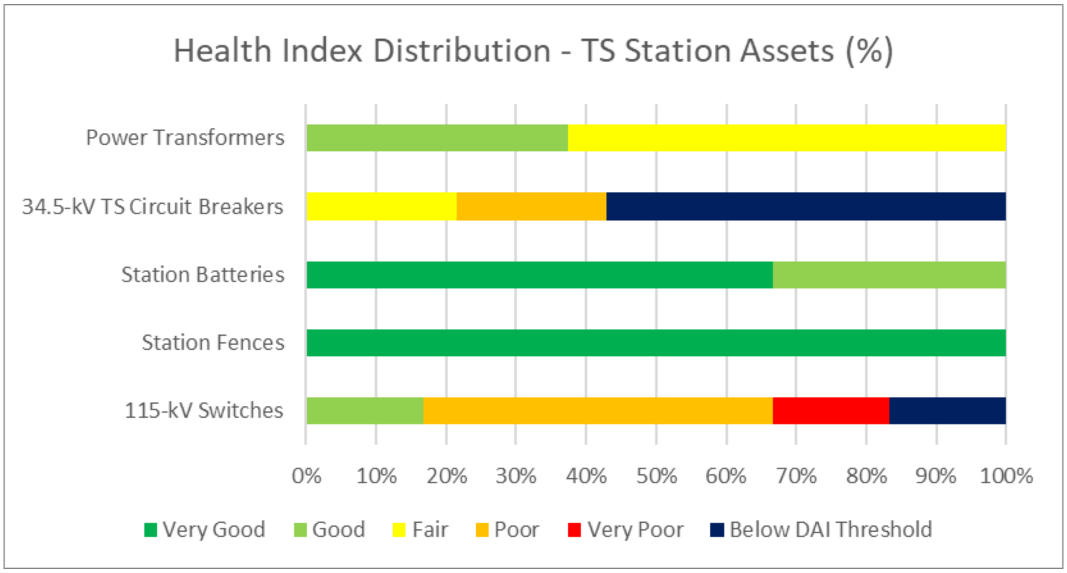
As

Figure 0-1 indicates, there are a significant number of assets in Fair condition that will require intervention over the long-term and may require intervention in the short-term depending on risk. In particular, Poor or Very Poor condition assets have been identified across the system which should be assessed for replacement or refurbishment over the short-term.

Figure 0-2 summarizes the ACA results for PUC's station assets. Due to the much smaller asset population compared to distribution assets, the HI results for station assets are not extrapolated when the DAI is insufficient to calculate a valid HI.

Figure 0-2: Station Asset Health Index Results





As Figure 0-2 indicates, there are a significant number of assets – in particular, 115-kV switches, power transformers, medium-voltage switchgear, and 34.5-kV circuit breakers – in Fair condition that will require intervention in the long-term and may require intervention in the short-term depending on risk. Stations assets serve many downstream customers and are generally higher risk compared to distribution assets. There are also several assets in Poor condition that will require intervention in the short-term.

Table 0-2: Asset Condition Assessment Overall results

presents the numerical HI summary for each asset class. The HI distribution is based on the total population count of a given asset class. For each asset class, the population, average HI, average DAI, and HI distribution are listed.

Table 0-2: Asset Condition Assessment Overall results

Asset Class	Population	Health Index Distribution (%)					
		Very Good	Good	Fair	Poor	Very Poor	Below DAI Threshold
Distribution Assets							
Wood Pole	12,548	25.13%	44.08%	21.51%	4.70%	4.57%	
Steel Pole	57	Age Only					
Overhead Primary Conductor	614.9 km	Age Only					
Underground Primary Cable	123 km	15.60%	16.42%	26.99%	27.79%	3.21%	
Pole-Mount Transformer	4806	26.57%	24.69%	36.23%	6.85%	5.67%	
Pad-Mount Transformer	939	30.22%	17.20%	47.59%	3.49%	1.50%	
Submersible Transformer	468	19.01%	5.55%	48.08%	19.44%	7.91%	
Distribution Switchgear	25	48.00%	48.00%	4.00%	0.00%	0.00%	
Fused Switches	1536	Age Only					
Disconnect Switches	905	Age Only					
Substation Assets							
Power Transformer	26	12.12%	27.27%	57.58%	3.03%	0.00%	
Medium Voltage Switchgear (12.47-kV)	13	0.00%	0.00%	21.43%	21.43%	0.00%	57.14%
Medium Voltage Switchgear (4.16-kV)	3	Age Only					
Medium Voltage Switchgear (34.5-kV)	14	Age Only					
Station Service Transformer	17	Age Only					
Substation Battery	14	71.43%	7.14%	21.43%	0.00%	0.00%	
Substation Buildings	10	20.00%	10.00%	10.00%	0.00%	0.00%	
Station Fences	14	60.00%	40.00%	0.00%	0.00%	0.00%	
Station Riser Cables	94	0.00%	60.00%	11.43%	1.43%	0.00%	27.14%
TS Assets							
Power Transformer	8	0.00%	37.50%	62.50%	0.00%	0.00%	
34.5-kV TS Circuit Breaker	22	0.00%	0.00%	22.73%	22.73%	0.00%	54..54%
Station Battery	3	66.67%	33.33%	0.00%	0.00%	0.00%	
Station Fences	2	100.00%	0.00%	22.73%	22.73%	0.00%	
115-kV Switches	12	0.00%	16.67%	0.00%	50.00%	16.67%	16.67%

PUC's Current Health Index Maturity and Continuous Improvement

Overall, PUC's asset data collection practices are sufficiently robust to enable calculation of the recommended ACA that is consistent with industry best practices. The average DAI scores are very high across most asset classes. Asset condition information is unavailable for steel poles, overhead transformers, fused and load-break switches, and station service transformers – all of which have been assessed based on age only. Notably, among the assets with HI scores, submersible transformers and station riser cables have the most room for improvement in DAI and should receive increased attention over the next maintenance cycle.

While the HIF formulation and DAI have been determined based on available condition parameters, there are opportunities for PUC to introduce additional variables that can provide further insight into the degradation level of a given asset class. For example, visual inspection results would aid the assessment of station riser cables and detailed loading history could be used to assess the condition of primary cables.

While the existing framework provides PUC with a significant volume of data, certain procedural and technological enhancements could further the granularity of its asset condition data and facilitate calculation of a greater proportion of numerical degradation scores. For example, PUC's maintenance database is not coordinated with its Geo-spatial Information System ("GIS") in some cases. Furthermore, routine inspections done by PUC could be used as an opportunity to collect condition information for long-term planning in addition to identifying corrective maintenance needs.

In providing these recommendations, METSCO is cognizant of the fact that regulated utilities are facing cost constraints across numerous facets of their operations, while contending with the effects of aging infrastructure, changing climate, evolving customer needs, and many other priorities. As such, an adoption of any incremental enhancement to the existing asset data collection practices must be grounded in management's assessment of the incremental value of such enhancements, relative to the opportunity cost of advancements elsewhere in the utility's operations. METSCO makes this observation to highlight its position that the sole fact of a gap between a utility's current process state and the industry best practices need not necessarily indicate that an action to remedy that gap is required in short order.

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1 Introduction

METSCO Energy Solutions Inc. ("METSCO") is an industry expert in Asset Condition Assessment ("ACA") and Asset Management ("AM") practices due to our extensive experience in conducting ACAs, developing AM plans, and implementing AM frameworks for transmission and distribution utilities across North America. METSCO's collective record of experience in these areas is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions. A selection of METSCO's past projects is attached as Appendix A to this report.

PUC Distribution Inc. ("PUC") is an electricity distributor operating in the City of Sault Ste. Marie, the Batchewana First Nation (Rankin Reserve), Prince Township, and parts of Dennis Township. PUC engaged METSCO to prepare a comprehensive ACA study for the assets comprising PUC's electrical system. The ACA is required as one of the key inputs for the preparation of PUC's five-year Distribution System Plan, prepared in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB"). The study's primary objective is to objectively determine the condition of PUC's assets as a key step in the capital expenditure process for renewal investments. Supplementary objectives include preparing the ACA results to be used for PUC's upcoming rate filing as well as to continuously improve PUC's AM framework.

A unique ACA methodology is applied to each asset class deployed within PUC's system. The adoption of the ACA methodology requires identifying end-of-life criteria for various components associated with each asset type, followed by periodic asset inspections and recording of asset condition to identify the assets most at risk at reaching the end-of-life criteria over the planning horizon. Each criterion represents a factor that is influential, to a specific degree, in determining an asset's (or its component's) condition relative to its potential failure. These components and tests are weighted based on their importance in determining the assets' end-of-life.

The assets covered in the report include the following major asset classes:

- Wood Poles
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Transformers (Pole-mount, Pad-mount, or Submersible)
- Pad-mount Distribution Switchgear

- Fused Disconnect Switches (Cut-outs)
- Load-Break Switches
- Underground Switches (Junction Boxes)
- Station Power Transformers
- 115-kV Station Switches
- 34.5-kV Station Circuit Breakers
- Medium-Voltage Station Switchgear (34.5 kV, 12.47 kV, or 4.16 kV)
- Station Service Transformers
- Station Battery Banks and Chargers
- Station Building Facilities
- Station Fences
- Station Riser Cables

All the asset condition data is maintained by PUC as part of its regular AM and maintenance practices. All condition information was collected by PUC and its contractors up to September 2021. This data was transmitted to METSCO between May and September 2021 to complete the ACA.

Major assets which do not fall within the scope of this assessment include:

- 115-kV transmission lines (structures, conductors, insulators, skywires, hardware, guywires, grounding, etc.)
- SCADA and communications systems
- Station grounding system (grid, bonding, etc.)
- Secondary bus and service conductors/cables
- Office buildings and facilities

To supplement the information provided by PUC, METSCO conducted a site visit in August 2021 to assess the condition of PUC's TS and substations, focusing on power transformers, outdoor circuit breakers, station buildings, and station fences. The site visit involved a visual inspection and infrared ("IR") scan. In addition, METSCO assessed the condition of PUC's medium-voltage switchgear, battery banks, and chargers based on photos and IR scans obtained by PUC.

The report is organized into six sections including this introductory section:

- Section 2 summarizes the ISO 5500X AM standards, discusses how the ACA fits into the overall AM framework; and provides an overview of METSCO's ACA methodology;
- Section 3 summarizes the asset Health Index ("HI") calculation methodology;
- Section 4 provides the Condition Assessment methodology framework and assessment for each of the identified asset classes;
- Section 5 provides METSCO's conclusions; and
- Section 6 summarizes METSCO's recommendations for PUC on data collection improvements for continuous improvement efforts for the ACA.

2 Context of the ACA within AM Planning

The ACA is a key step in developing an asset replacement strategy. By evaluating the current set of available data related to the condition of in-service assets comprising an organization's asset portfolio, condition scores for each asset are determined. The ACA involves the collection, consolidation, and utilization of the results within an organizational AM framework for the purposes of objectively quantifying and managing the risks of its asset portfolio. The level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure feed directly into the risk evaluation process, which identifies asset candidates for intervention (i.e., replacement or refurbishment). Assets are then grouped into program and project scopes that are evaluated and prioritized.

The ACA is designed to provide insights into the current state of an organization's asset base, the risks associated with identified degradation, approaches to managing this degradation within the current AM framework, and how to best make use of these results to extract the optimal value from the asset portfolio going forward.

2.1 International Standards for AM

The following paragraphs serve as a brief introduction to the ISO standards and provide a brief overview of the applicability of AM standards within an entity.

The industry standard for AM planning is outlined in the ISO 5500X series of standards, which encompass ISO 55000, ISO 55001, and ISO 55002. Each business entity finds itself at one of the three main stages along the AM journey:

1. Exploratory stage - entities looking to establish and set up an AM system;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous improvement stage - those looking to assess and progressively enhance an AM system already in place for avenues of improvement.

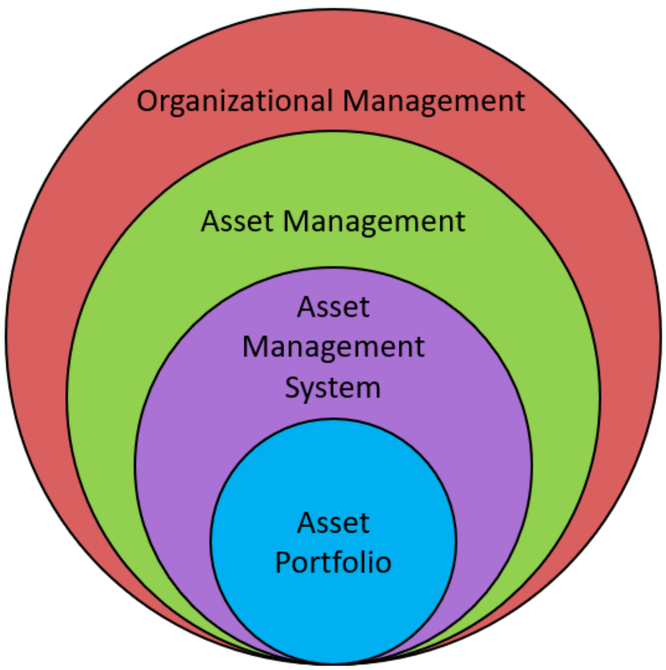
Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organizations can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.[1]

[1] ISO 55000 – Asset management – Overview, principles and terminology

An asset is any item or entity that has a value to the organization. This can be actual or potential value, in a monetary or otherwise intangible sense (e.g., public safety). The hierarchy of an AM framework begins with the asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. The ACA is the procedure to turn the known condition information into actionable insights based on the level of deterioration.

Around the asset portfolio, the AM system operates and represents a set of interacting elements that establish the policy, objectives, and processes to achieve those objectives. The AM system is encompassed by the AM practices – coordinated activities of the organization to realize maximum value from its assets. Finally, the organizational management organizes and executes the underlying hierarchy.[1]

Figure 2-1: Relationship between Key AM terms[1]



2.2 ACA within the AM Process

A well-executed AM strategy hinges on the ability of an organization to classify its assets via comprehensive and extensive data and data collection procedures. This includes but is not limited to:

- Collection and storage of technical specifications;
- Historical asset performance;
- Projected asset behaviour and degradation;
- Configuration of an asset or asset-group within the system; and
- Operational relationship of one asset to another.

In this way, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted and stored from its asset base to allow for further analysis and insights to be made. With more asset data on hand, better and more informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[2]

AM is fundamentally grounded in a risk-based evaluation of continued value. The overarching goal of an AM process is to quantify all assets risk by their probability and impact (where possible) and then look to minimize these risks through AM operations and procedures. The ACA quantifies the condition of each asset under study and is an appropriate indicator of its failure probability. Making asset replacement decisions directly based on the ACA results constitutes a condition-based intervention strategy.

AM practices can help quantify and drive strategic decisions. A better understanding of the asset portfolio and how it is performing within an organization will allow for optimal decision-making. This is largely due to best AM practices being a fundamentally risk-based approach, which lends it to be a structured framework for creating financial plans driven by data. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 55002 states explicitly that all asset portfolio improvements should be assessed via a risk-based approach prior to being implemented.[2] The criticality of the asset determines its failure impact. A risk-based asset intervention strategy should consider both the probability and impact in the decision-making process.

2.3 Continuous Improvement in the AM Process

The application of rigorous AM processes can produce multiple types of benefits for an organization including, but not limited to: realized financial profits, better classified and managed risk among assets, better-informed investment decisions, demonstrated

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

compliance among the asset base, increased public and worker safety, and corporate sustainability.[1]

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that is shared between all relevant agents. In this way, the organization stands to benefit the most from its internal resources, whether it be via technical experts, those operating and maintaining the assets or those with an understanding of the financial operations and constraints on the organization. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan ("SAMP"). The SAMP should be used as a guide for the organization to apply its AM principles and practices for its specific use case. Distribution of the SAMP should be well-publicized within an organization and updated on a regular basis, to best quantify the most current and comprehensive AM practices being implemented. Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor.[1]

AM should be regarded as a fluid process. Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio. Continually improved asset data and data collection procedures, updated SAMPs, and further integration into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework.[2]

3 Asset Condition Assessment Methodology

3.1 METSCO's Project Execution

METSCO's execution path in completing the ACA study can be is a four-phase procedure:

1. *Initial information gathering*: including initial interviews with PUC staff to investigate system configuration and the prominence of certain asset classes, establish the range of available condition data sources at the beginning of the engagement, and confirm the key assumptions regarding these factors with PUC subject matter experts through a series of interviews.

2. *Remote condition assessment* – follow-up review of asset photos and IR scan results for medium-voltage circuit breakers, station batteries, and chargers to assess their condition based on METSCO's established criteria.

3. *On-site inspections* – follow-up site visit to visually inspect and IR scan PUC's power transformers, high-voltage oil circuit breakers, station buildings, and station fences.

4. *Database construction* – activities to construct a single database of condition-related information for each PUC asset class using the provided data sources. This includes consolidation of PUC's asset inspection records, databases containing results of technical tests performed by PUC contractors, and the entire database from the Geographic Information System ("GIS").

5. *HI and Data Availability Index ("DAI") calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, METSCO calculated the Health Indices and DAI for all asset classes. Additional data sources were requested from PUC to improve the accuracy of the asset health calculation if applicable.

6. *Results Reporting* – the final phase of the project scope was the creation of the ACA report.

3.2 Data Sources

To assess the demographics and establish the unit population of PUC's system assets, METSCO was provided with PUC's asset demographic data from its current Geographic

Information System ("GIS"). These data came from PUC's corporate asset registries containing information on asset vintage, model, and year of commissioning. The database served as the primary asset library that contained asset nameplate information such as age and unique identifiers.

To assess the condition of PUC's system, METSCO was provided with available asset inspection and maintenance data for the asset classes in scope. Various sources hold records of PUC's inspection and maintenance activities. Most of these data came from primary sources such as equipment inspection forms completed by PUC staff or contractors, or the results of specific tests such as the Dissolved Gas Analysis ("DGA") for station power transformer oil.

Additionally, METSCO was provided with historical operating data for assets that require operating information for the HI calculation. An example of operating data used is the historical loading information for transformers.

3.3 Asset Condition Assessment Methodologies

Prior to completing an ACA, a methodology needs to be selected for the current entity. The four most common methodologies that can be employed to assess the condition of the system health include:

1. Additive models – asset degradation factors and scores are used to independently calculate a score for each individual asset, with the HI representing a weighted average of all individual scores from 0 to 100;
2. Gateway models – select parameters deemed to be most impactful on the asset's overall functionality act as "gates" to drive the overall condition of an asset, by effectively "deflating" the scores of other (less impactful) components;
3. Subtractive models – consider that a relatively Poor condition for any of several major assets within a broader system of assets could act as a sufficient justification to drive investments into the entire system; and
4. Multiplicative models – a HI that dynamically shifts the calculation towards specific degradation factors, if they are a leading indicator to show that an asset is failing.

The additive and gateway models are typically used for assessing individual assets, whereas the subtractive and multiplicative models are typically used for aggregate and composite system-level assessments. The latter models are still in an early stage and require extensive refinement and validation to confirm their applicability. The gateway model assigns gates to criteria or asset subcomponents which are difficult or expensive to replace and maintain, and/or are known to be a major cause of asset malfunctioning. This methodology is commonly used in conjunction with the additive model for major assets such as wood poles, where a "gate" score will act to reduce the HI due to a low recorded score for a given criterion. For example, if the remaining strength of a wood pole is less than 60%, the final HI for that asset is halved.

In general, most distribution utilities employ an additive model with select gateway model elements. METSCO selected this approach when conducting the ACA, which is in alignment with most of PUC's peer utilities.

3.4 Overview of Selected Methodology

3.4.1 Condition Parameters

To calculate the HI for an asset, formulations are developed based on condition parameters that can be expected to contribute to the degradation and eventual failure of that asset. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 3-1**Error! Reference source not found.** exemplifies a HI formulation table.

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded to each asset class. Additionally, some condition parameters can be comprised of sub-condition parameters. For example, the oil quality condition parameter for a station power transformer is based on multiple sub-condition parameters such as the acidity of the oil, its interfacial tension, dielectric strength, and water content.

Figure 3-1: HI Formulation Components

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

The scale used to determine an asset's score for a condition parameter is called the "condition indicator". Each condition parameter is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a condition score of 4 represents the best grade, whereas a condition score of 0 represents the worst grade.

A – 4 Best Condition

B – 3 Normal Wear

C – 2 Requires Remediation

D – 1 Rapidly Deteriorating

E – 0 Beyond Repair

3.4.2 Use of Age as a Condition Parameter

Some industry participants question the appropriateness of including age as a potential condition parameter for calculating asset HI values. At the core of the argument against the use of age in calculating asset condition is the notion that age implies a linear degradation path for an asset that does not always match the actual experience in the field.

While some assets lose their structural integrity faster than would be expected with the passage of time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer period than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, METSCO limits the instances where it relies on only age as a parameter explicitly incorporated into the HI formulation. In some cases, however, the limited number of condition parameters available for calculation of asset health makes age a useful proxy for the important factors that the analysis would not otherwise capture. In other cases, such as when assessing condition of complex equipment containing several internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing, age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

3.4.3 Final Health Index Formulation

The final HI, which is a function of the condition scores and weightings, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score} \right) x\ 100\%$$

Where *i* corresponds to the condition parameter number, and the HI is a percentage representing the remaining life of the asset.

A gating approach is used for condition parameters that have a significant influence on the health of an asset. If the condition parameter that has been flagged as a gating parameter is below a pre-defined threshold value, the overall HI is reduced by 50%. This approach enables utilities to efficiently flag severely degraded assets through identification of condition parameters acknowledged to be critical indicators of overall asset health.

3.4.4 Health Index Results

METSCO's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset, ranging from Very Good to Very Poor. To assign each asset into one of the categories, METSCO constructs an HI formulation for each asset class, which captures information on individual degradation factors contributing to that asset's declining condition over time. Condition scores assigned to each degradation factor are also expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual degradation factors, with each of the five condition categories (Very Good, Good, Fair, Poor, Very Poor) corresponding to a numerical band. For example, the condition score of Very Good indicates assets with HI values between 100% and 85%, whereas assets found to be in a Very Poor condition score are those with calculated HI values between 0% and 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 3-1 presents the HI ranges with the corresponding asset condition, its description as well as implications for maintaining, refurbishing or replacing the asset prior to failure.

Table 3-1: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85]	Good	Significant Deterioration of some components	Normal Maintenance
[50-70]	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50]	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30]	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

3.5 Data Availability Index

To put the calculation of HI values into the context of available data, METSCO supplemented its HI findings with the calculation of the DAI: a measure of the availability of the condition parameter data for a specific asset weighted by each condition parameter to the HI score. The DAI is calculated by dividing the sum of the weights of the condition parameters available to the total weight of the condition parameters used in the HI formulation for the asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\%$$

Where i corresponds to the condition parameter number and α is the availability of coefficient (=1 when data available =0 when data unavailable)

An asset with all condition parameter data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. For distribution assets – typified by relatively large asset populations – if the DAI for an asset is less than 70%, a valid HI cannot be calculated. The subset of distribution assets without a valid HI are assigned an extrapolated HI value using the valid HI results for assets within the same asset class and ten-year age band. Similarly for station assets – typified by relatively small asset populations – if the DAI for an asset is less than 65%, a valid HI cannot be calculated. HI results for station assets are not extrapolated due to the small population.

4 Health Index Formulations and Results

This section presents the developed HI formulation for each asset class, the calculated scores for HI results, and the data available to perform the study.

4.1 Distribution Assets

4.1.1 Wood Poles

Wood poles are an integral part of any distribution system. They are the support structures for overhead distribution system. The HI for wood poles is calculated by considering a combination of end-of-life criteria summarized in Table 4-1.

Table 4-1: Wood Pole HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Remaining Strength	8	A,B,C,D,E	4,3,2,1,0	32
Pole Treatment Type	3	A,C,E	4,2,0	12
Mechanical Condition	4	A,B,C,D,E	4,3,2,1,0	16
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**76**

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage, and weather effects which can impact the mechanical strength of the pole. Any loss in the strength of the pole can present additional safety and environmental risks to the public and to PUC. The remaining strength condition parameter is a quantitative measurement that provides adequate evidence of the deterioration of the operational health of the asset.

The HI formulation for wood poles is a combination between the additive and gateway model; with the gateway applied to the remaining strength parameter. When the remaining strength for a pole is below 60%, the final HI for that pole is reduced by half. CSA standard C22.3 no. 1 requires that any pole with a remaining strength less than 60% of its design strength be replace or reinforced[3]. PUC only tests poles that are ten years old or more; therefore, once a pole reaches ten years of age it is scheduled for testing on the seven-year

[3] *Overhead Systems*, CAN/CSA C22.3 No.1-15, 2015

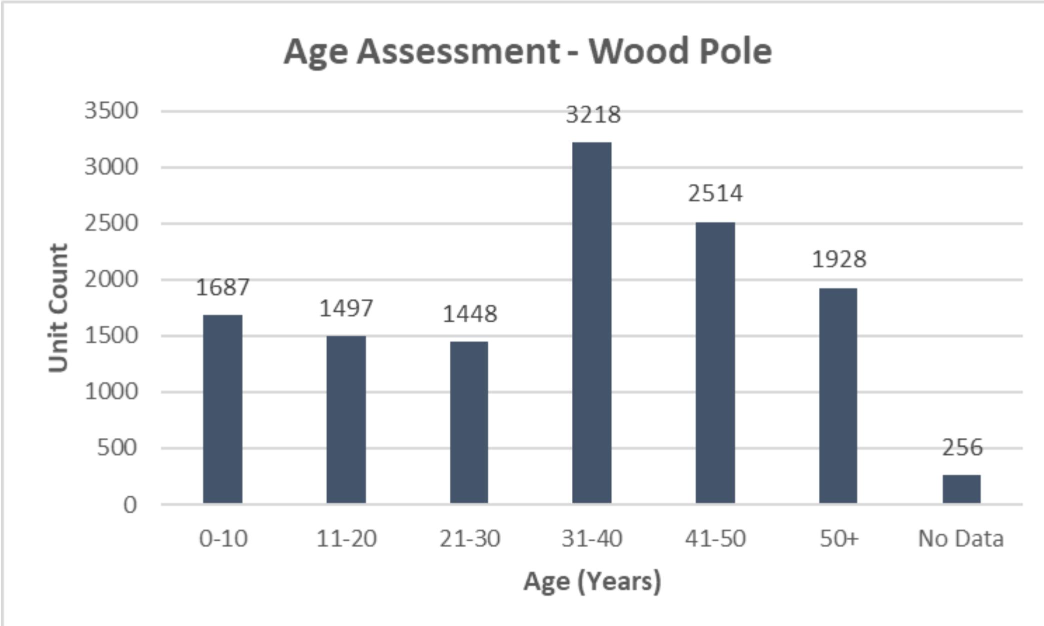
test cycle. To account for this in the ACA, poles which are fifteen years old or less are not treated as requiring a Remaining Strength value.

Additional condition parameters include service age, mechanical condition, and the pole treatment type. The mechanical condition of a pole is comprised of many factors, which are:

- Pole-top feathering
- Wood pole hole
- Surface rot below ground line
- Internal decay
- Ground line
- Crossarm rot
- Decay pockets at ground line
- Surface rot above ground line
- Mechanical damage
- Cracks
- Fire damage
- Carpenter ants damage

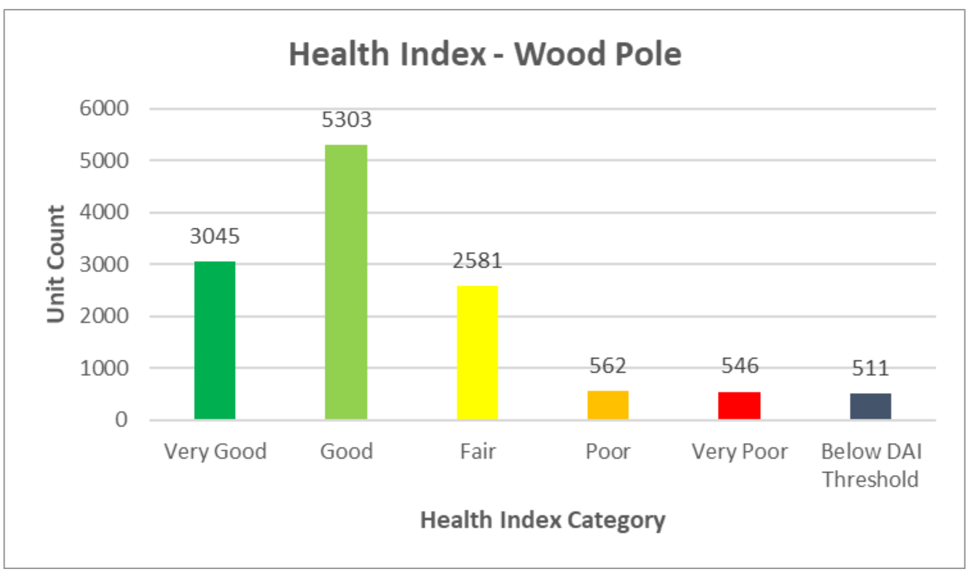
PUC owns approximately 12,600 wood poles within its service territory. Installation date is known for nearly 98% of the total in-service population. Figure 4-1 presents the age distribution for in-service wood poles.

Figure 4-1: Wood Poles Age Demographics



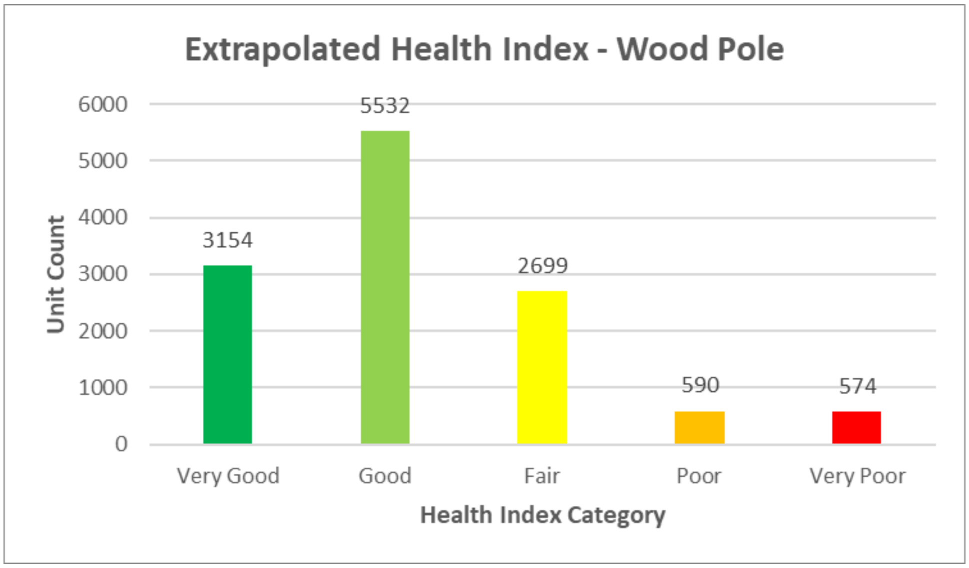
PUC's pole maintenance and nameplate data were used to calculate the HI based on the criteria provided Table 4-1. As shown in Figure 4-2, a valid HI was calculated for 96% of the wood poles.

Figure 4-2: Wood Pole HI Results



To complete the full analysis, the HI for the remaining 4% of poles has been extrapolated based on the HI distribution with a valid HI score within each ten-year age group. The overall extrapolated HI distribution for wood poles is presented in Figure 4-3.Most of the poles are in Very Good or Good condition with less than 12% of the total population being in Poor or Very Poor condition.

Figure 4-3: Extrapolated Wood Pole HI Results

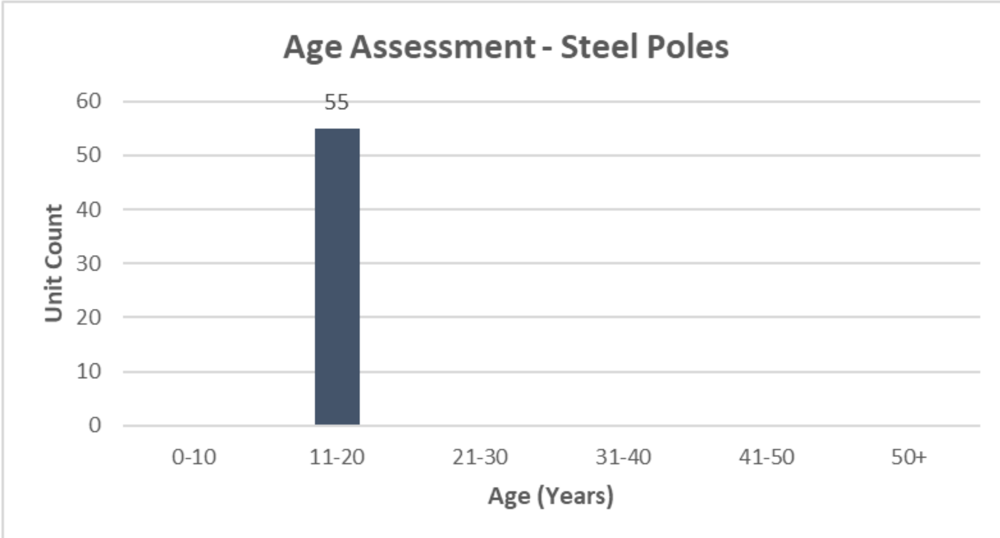


4.1.2 Steel Poles

Like wood poles, steel poles support the overhead distribution system. Steel is a conductive material and is not a typical pole type used by electric utilities; hence, PUC has a small number of steel poles on their distribution system. Due to the unavailability of inspection data for steel poles, health indices were not calculated.

PUC owns 55 steel poles within its service territory. The installation date is known for all steel poles, as shown in Figure 4-4.

Figure 4-4: Steel Pole Age Demographics



4.1.3 Overhead Primary Conductors

Overhead distribution conductors transmit electricity from generators to TS, from TS to substations, and from substations to customer premises and are supported by poles. Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for the tensile strength of the conductor and to determine the remaining life of the asset is the use of service age.

PUC owns 615 km of overhead distribution primary conductor with its service area. PUC's overhead distribution conductors operate at various voltage levels; 4.16kV, 12.47kV, 34.5kV and 115kV. Voltage level demographics are presented below in Figure 4-5. An age assessment was evaluated for the overhead conductor population, Figure 4-6 to Figure 4-8 below represent the overhead lines age distribution.

Figure 4-5: Overhead Lines Voltage Demographics

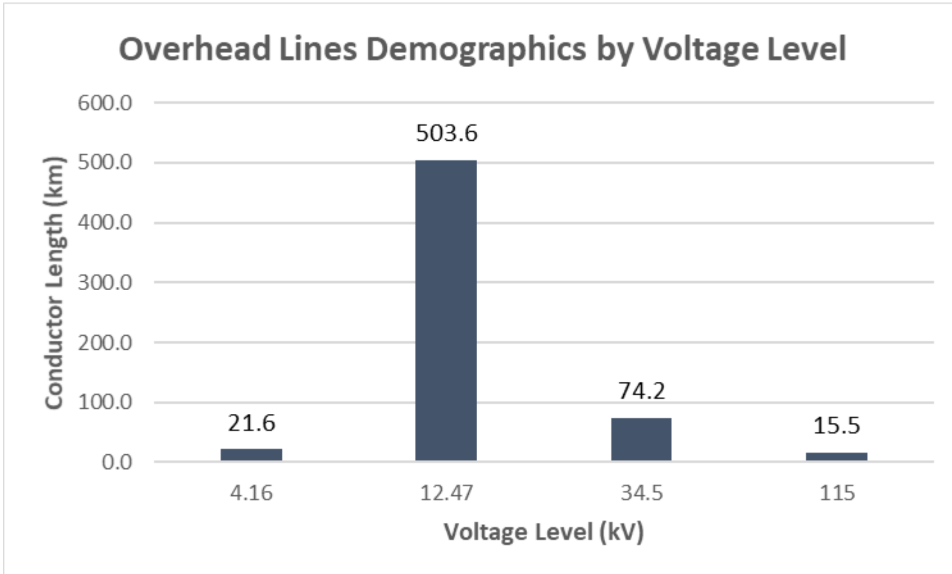


Figure 4-6: 1-Phase Overhead Line Age Demographics

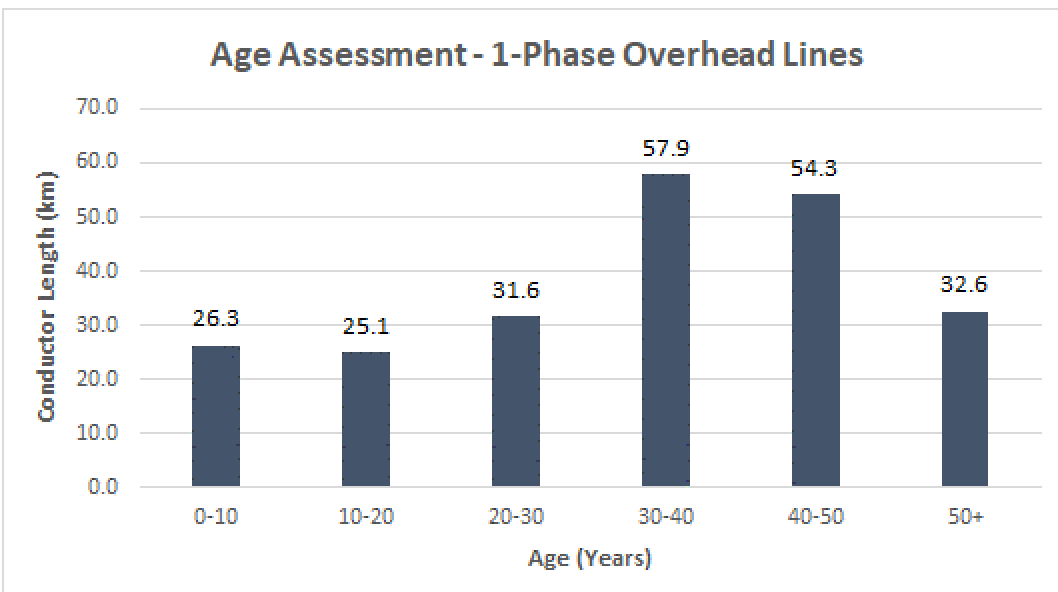


Figure 4-7: 2-Phase Overhead Lines Age Demographics

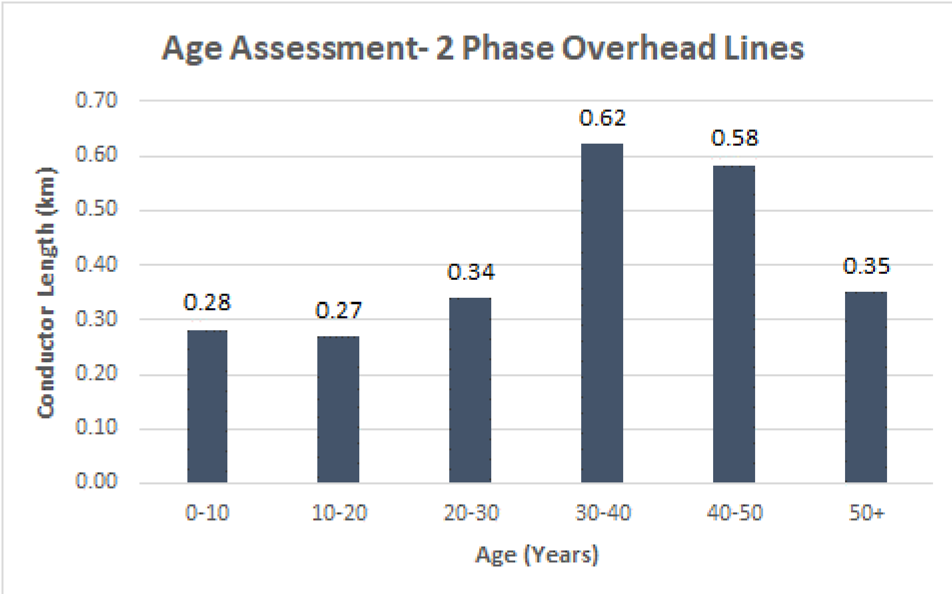
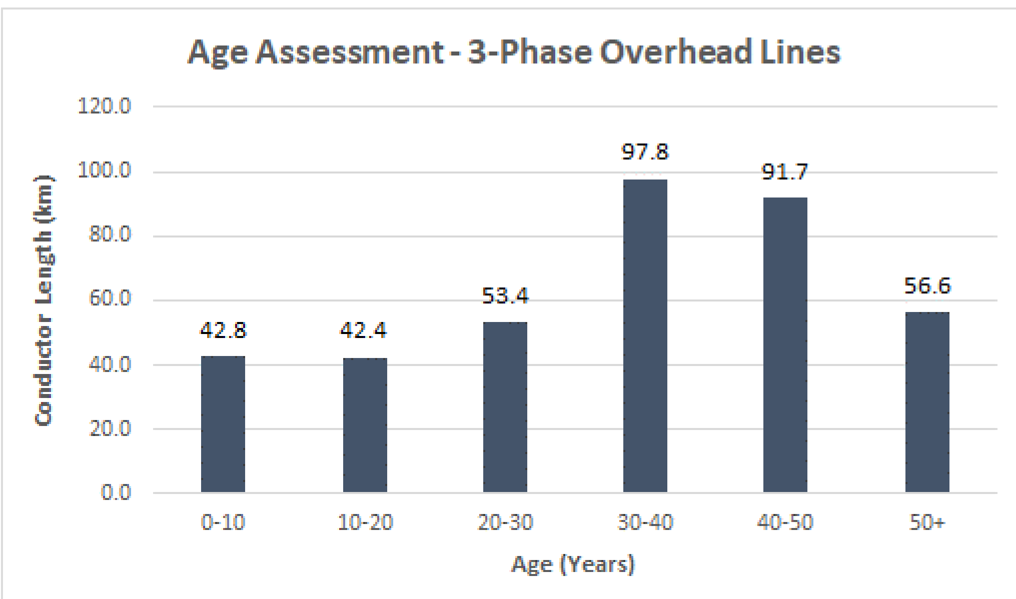


Figure 4-8: 3-Phase Overhead Line Age Demographics



4.1.4 Underground Primary Cables

Like overhead conductors, underground cables also transmit electricity along the electrical distribution system; however, they are located below ground. PUC's underground system consists of cross-linked polyethylene ("XLPE") cables for the most part, but also includes a mix of other insulation types including tree-retardant XLPE ("TR-XLPE"), butyl rubber, and an older General Electric cross-linked polymer dielectric known as "Vulkene".

Compared to overhead lines, cables can be more reliable since they are not exposed to severe weather conditions, tree contacts, or foreign interference. However, distribution underground cables use solid insulation (rather than air as used by the overhead system); thus, any cable fault is permanent until spliced out. Managing a cable system is more expensive and these are some of the more challenging assets in electricity systems from a condition assessment and AM viewpoint.

Several test techniques such as partial discharge ("PD") and water tree diagnostic testing have become available over recent years to identify the condition and performance of the asset class. Some tests can be destructive to the asset and hence are used less frequently. Accordingly, the preference is given to non-destructive testing. In the absence of test results, cable age can be used as a proxy for medium-term and long-term planning to predict quantities of cables that are expected to reach end-of-life.

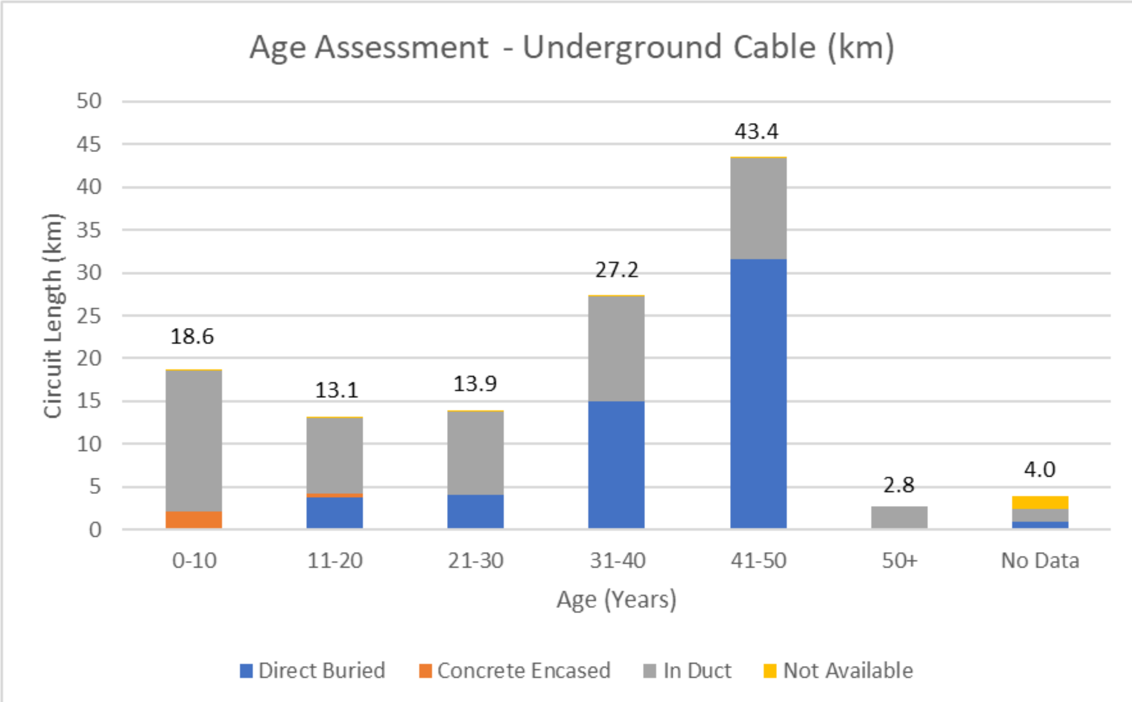
Due to the absence of test results, the health index formulation of underground cables only involved using the service age of the cable as well as the circuit's historical failures during the last five years. Table 4-2 presents the HI formulation of underground cables.

Table 4-2: Underground Cable HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	5	A,B,C,D,E	4,3,2,1,0	20
Circuit Failure Records	2	A,B,C,D,E	4,3,2,1,0	8
			Total Score	**28**

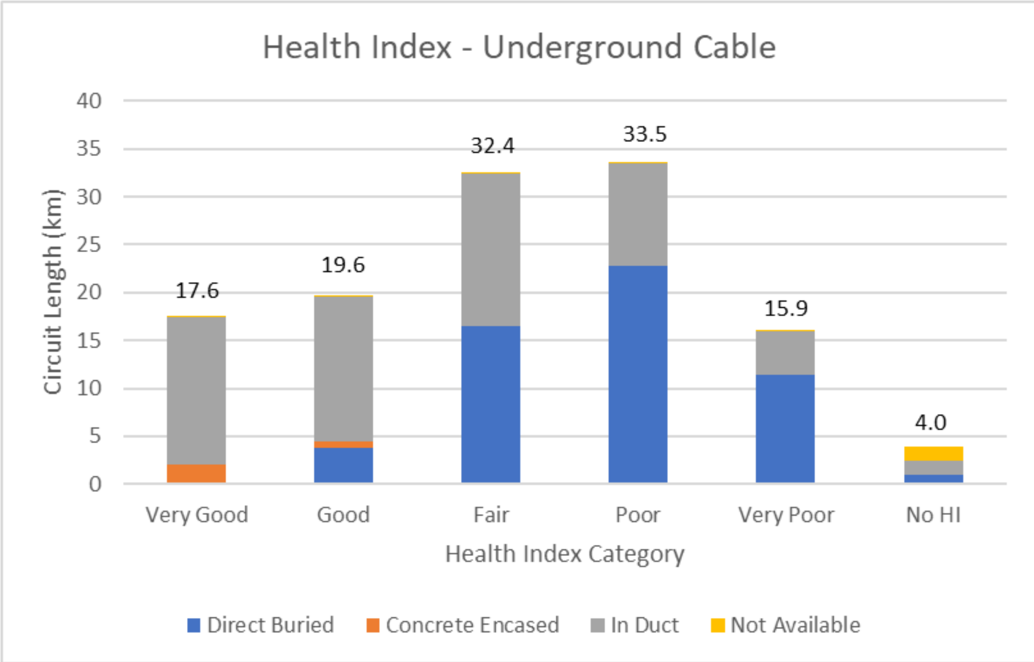
PUC owns approximately 123 km of underground primary cable within its service territory. Installation dates are known for nearly 97% of underground cable length. Figure 4-9 Figure 4-9 presents the total length of underground primary cables by the cables' buried status.

Figure 4-9: Overall Underground Primary Cable Age Demographics



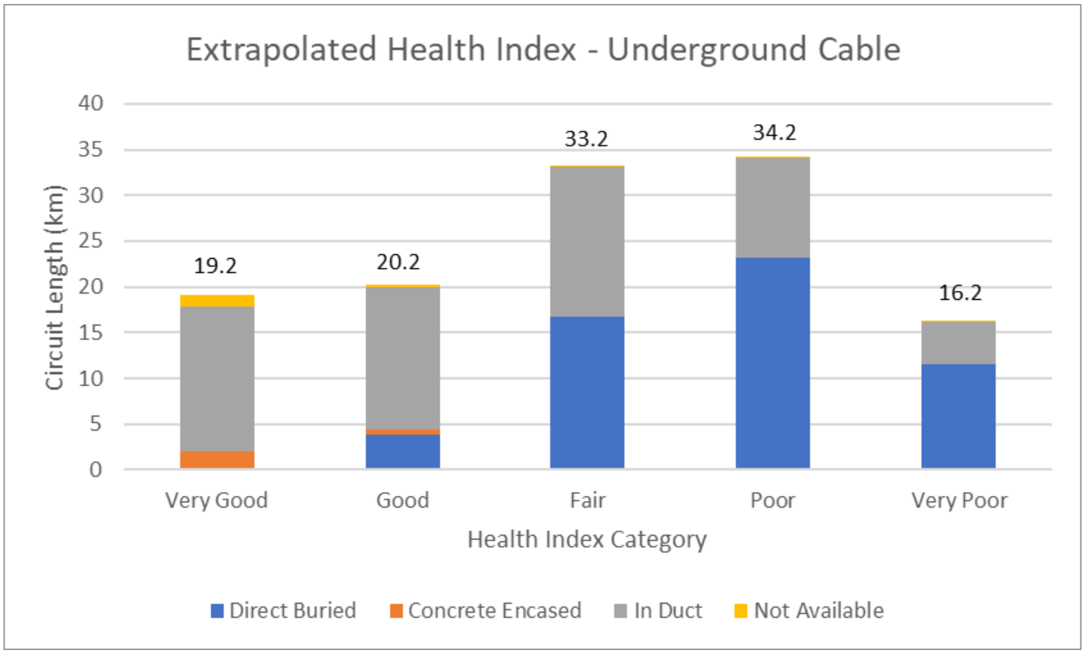
PUC's underground primary cable maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-2. As shown in Figure 4-10, a valid HI was calculated for 97% of underground cables.

Figure 4-10: Underground Cable HI Results



To complete the full analysis, the HI for the remaining 3% of cables has been extrapolated based on the HI distribution with a valid HI score within each ten-year age group. The overall extrapolated HI distribution for underground cables is presented in Figure 4-11. Approximately, 40% of the population is in Good or Very Good condition while the remaining 60% lie in "Fair" condition or worse.

Figure 4-11: Extrapolated Underground Cable HI Results



4.1.5 Pole-mount Transformers

Pole-mount transformers are installed on service poles above ground with the primary function to step down power from the medium-voltage distribution system to the voltage rating for customer use. The HI for pole-mount transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-3.

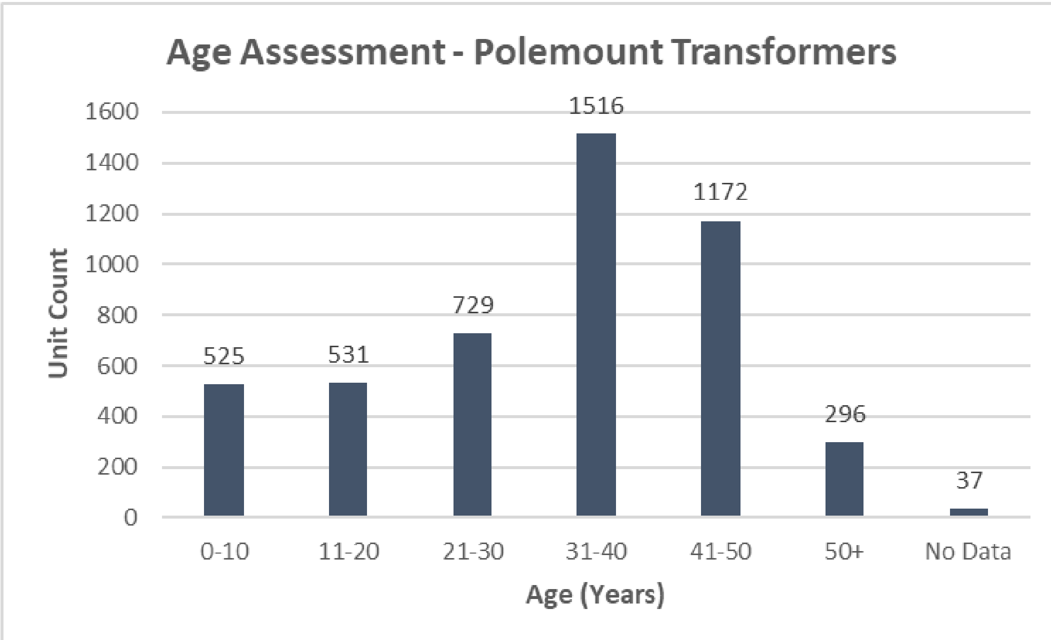
Table 4-3: Pole-mount Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Peak Loading	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**24**

In addition to service age, peak loading is used as a condition parameter. Load unbalances or peak loading can reduce the useful life of a distribution transformer.

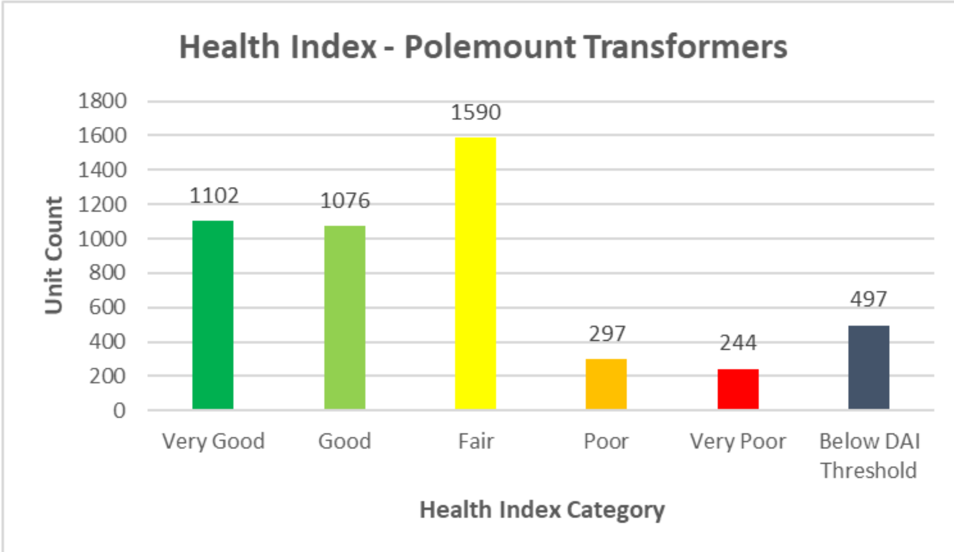
PUC owns 4,806 pole mount transformers within its service territory. Installation dates are known for 99% of the total in-service population. Figure 4-12 presents the age distribution for pole-mount transformers.

Figure 4-12: Pole-Mount Transformer Age Demographics



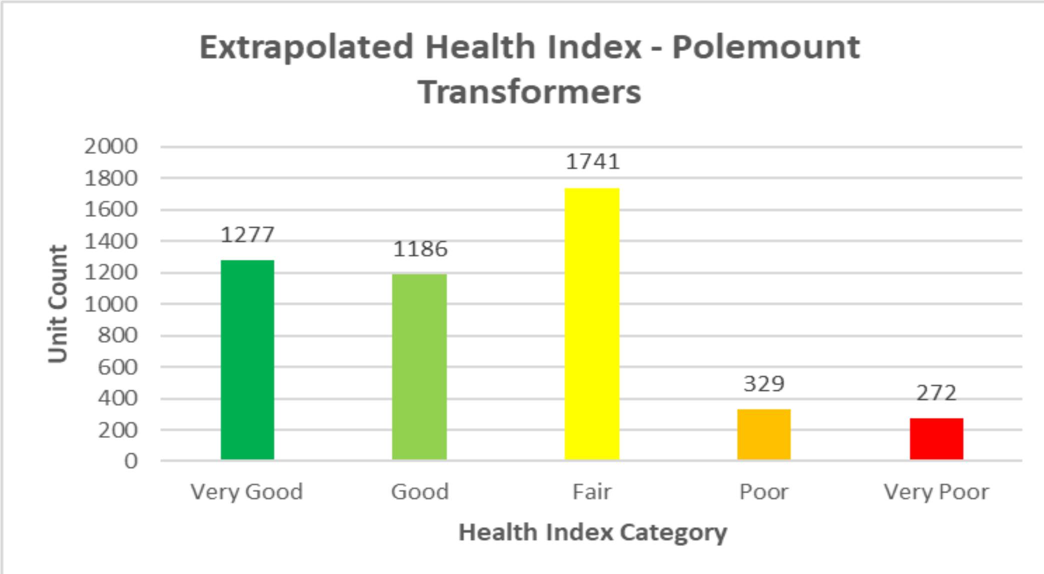
PUC's nameplate information and operating loading data were used to calculate the HI based on the criteria listed in Table 4-3. A valid HI was calculated for 90% of the overhead transformers. The HI results can be seen in Figure 4-13.

Figure 4-13: Pole-Mount Transformer HI Results



To complete the full analysis, the HI results for the remaining 10% of pole-mount transformers were extrapolated based on the HI distribution of the asset population with a valid HI score. The overall HI distribution for pole-mount transformers is presented in Figure 4-14. Nearly half of the population is in Very Good or Good condition, while over a third are in Fair condition.

Figure 4-14: Extrapolated Pole-Mount Transformer HI Results



4.1.6 Pad-mount Distribution Transformers

Pad-mount distribution transformers are utilized for similar functionalities as pole-mount transformers. They step down power from the medium-voltage distribution system to the final utilization voltage for the customer; however, they are placed on the ground level.

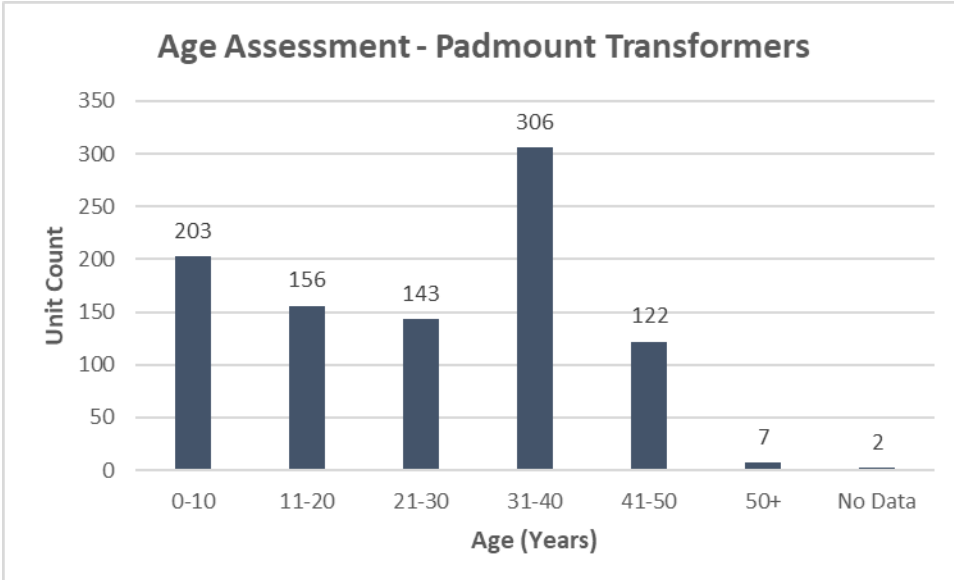
The HI for underground distribution transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-4.

Table 4-4: Pad-mount Distribution Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Peak loading	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**24**

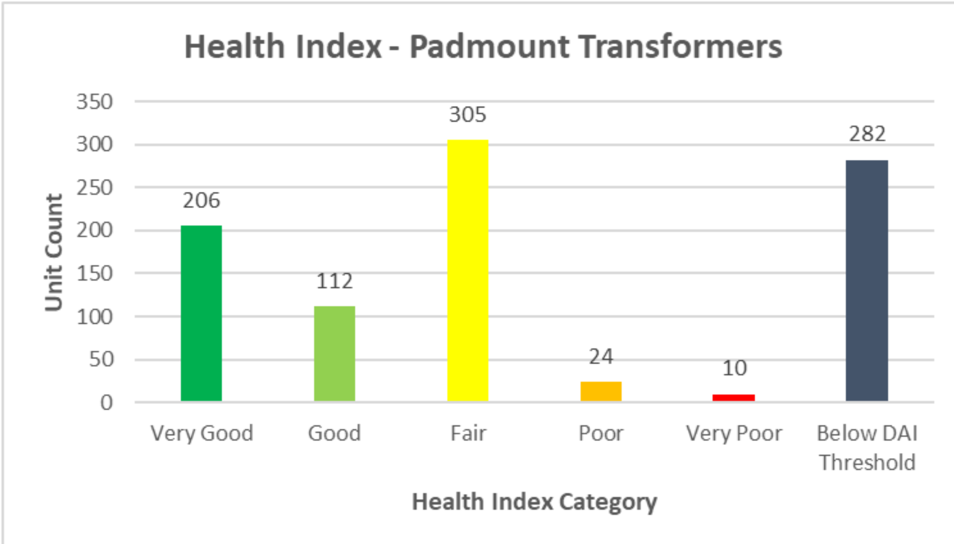
PUC owns 939 pad-mount transformers within its service territory. The installation dates are known for nearly the entire population. Figure 4-15 presents the age distribution for pad-mount transformers.

Figure 4-15: Pad-mount Transformer Age Demographics



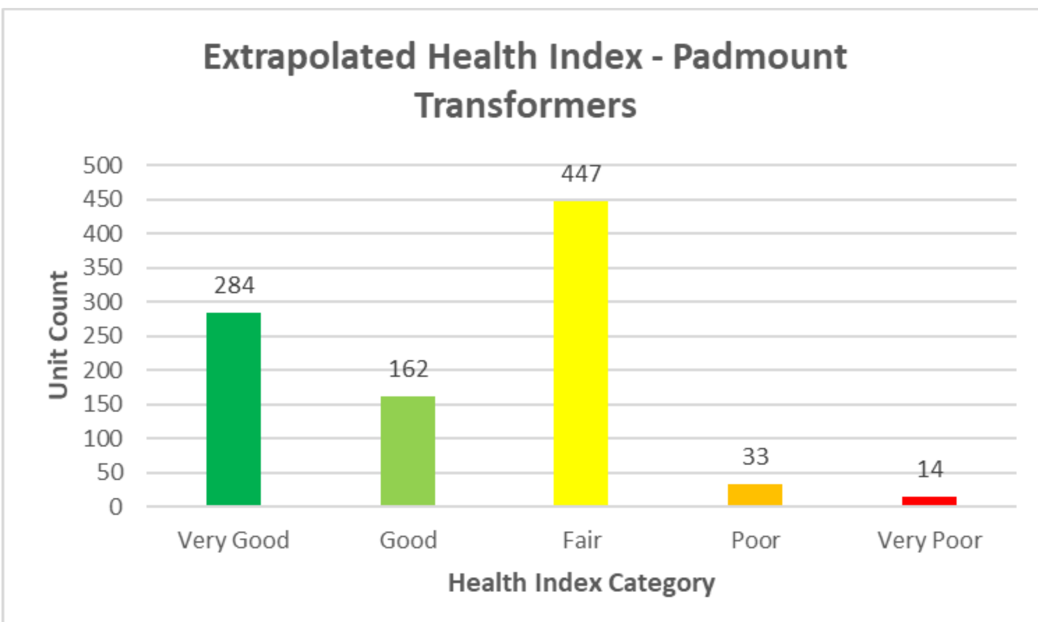
PUC's nameplate information and operational loading data were used to calculate the HI results based on the criteria provided in Table 4-4. Nearly 1.5% of the pad-mount transformers within PUC's service territory have peak loading percentage greater than 100% which can pose operating restrictions and impact the condition of the assets. The HI distribution is presented in Figure 4-16. A valid HI was calculated for 70% of pad-mount transformers.

Figure 4-16: Pad-mount Transformer HI Results



To complete the full analysis, the HI for the remaining population was extrapolated based on the HI distribution of the asset population with a valid HI score. As illustrated in Figure 4-17, most of the population is either in a Fair condition or better.

Figure 4-17: Extrapolated Pad-mount Transformer HI Results



4.1.7 Submersible Transformers

Submersible distribution transformers are utilized for similar functionalities as pole-mount and pad-mount transformers. They step down power from the medium-voltage distribution system to the final utilization voltage for the customer; however, they are placed below the ground level in a vault.

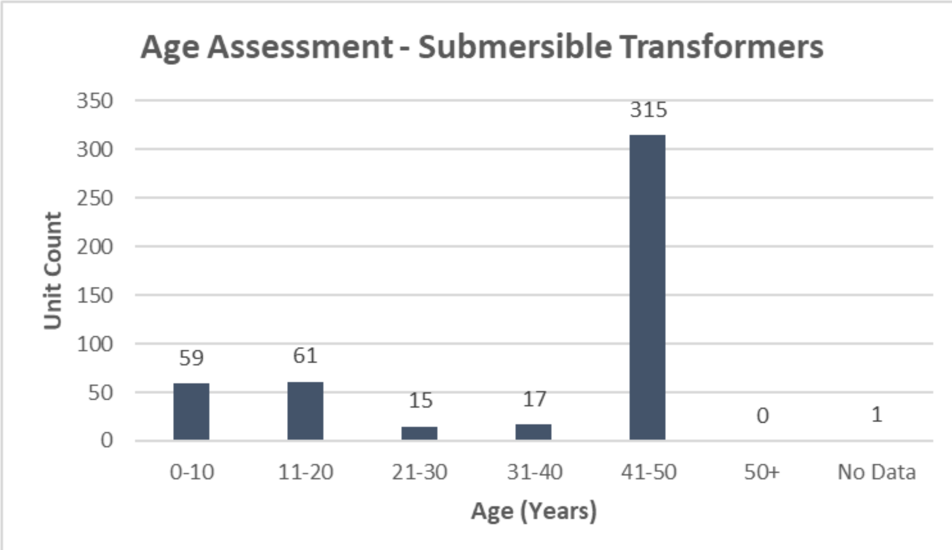
The HI for submersible transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-5. Several of PUC's vaults use tar paper, which is a flammable substance. Due to the higher probability of catastrophic failure, a condition parameter for whether the vault is made of tar paper is added.

Table 4-5: Submersible Distribution Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
End Grate Condition	1	A,B,C,D,E	4,3,2,1,0	4
Lid Condition	4	A,B,C,D,E	4,3,2,1,0	16
Corrosion on Tank	4	A,B,C,D,E	4,3,2,1,0	16
Debris	1	A,B,C,D,E	4,3,2,1,0	4
Terminations	2	A,B,C,D,E	4,3,2,1,0	8
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
Ground Straps	2	A,E	4,0	8
Tar Paper Vault	6	A,E	4,0	24
			Total Score	**96**

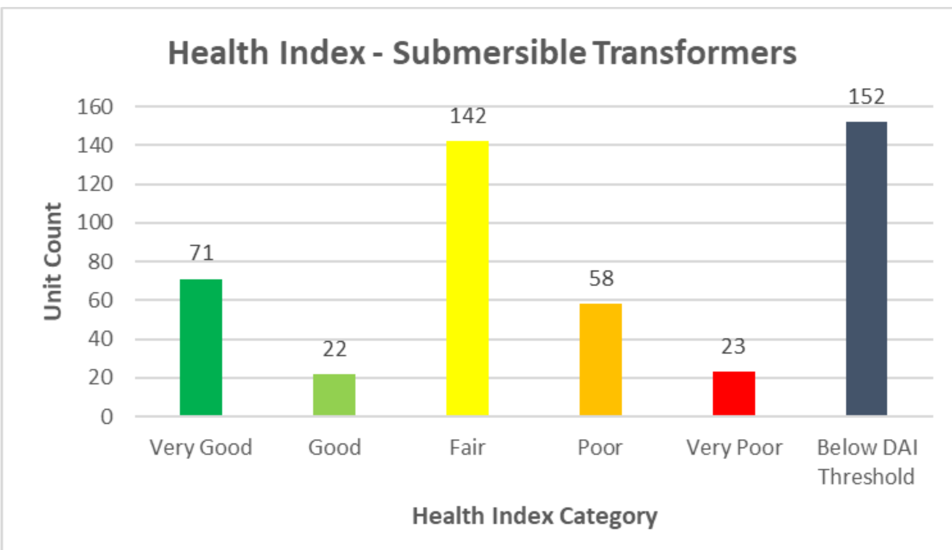
PUC owns 468 submersible transformers within its service territory. The installation dates are known for nearly the entire population. Figure 4-18 presents the age distribution for submersible transformers.

Figure 4-18: Submersible Transformers Age Demographics



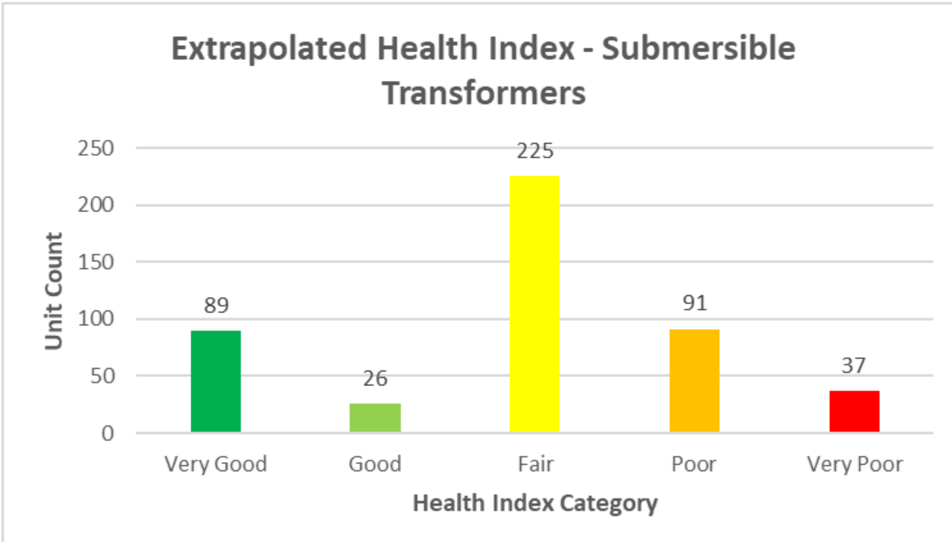
PUC's inspection data were used to calculate the HI results based on the criteria provided in Table 4-5. The HI distribution is presented in Figure 4-19. A valid HI was calculated for 68% of the population.

Figure 4-19: Submersible Transformer HI Results



To complete the full analysis, the HI for the remaining population was extrapolated based on the HI distribution of the asset population with a valid HI score. As illustrated in Figure 4-20, over 70% of the population is either in a Fair condition or better.

Figure 4-20: Extrapolated Submersible Transformer HI Results



4.1.8 Underground Switches

PUC's underground switches are junction boxes manufactured by Kbar that can be operated if needed. The HI for underground switches is calculated by considering a combination of end-of-life criteria summarized in Table 4-6.

Table 4-6: Underground Switch HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Visual Inspections	1	A,B,C,D,E	5,4,3,2,1	5
			Total Score	**5**

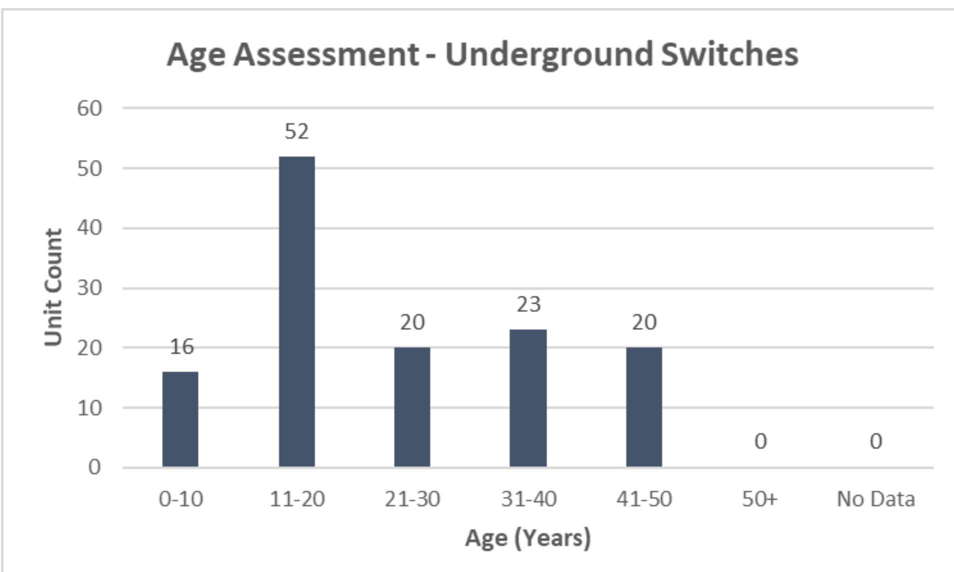
The visual inspections comprise of multiple inspection parameters:

- Paint condition
- Pad
- Sealed
- Doors, locks, and latches
- Water ingress

- Conduits
- Condensation
- Contamination
- Grounding
- Physical condition
- Electrical clearances
- Terminations
- Installations
- Insulator condition
- Switch contacts
- Fuses
- Fuse Holders

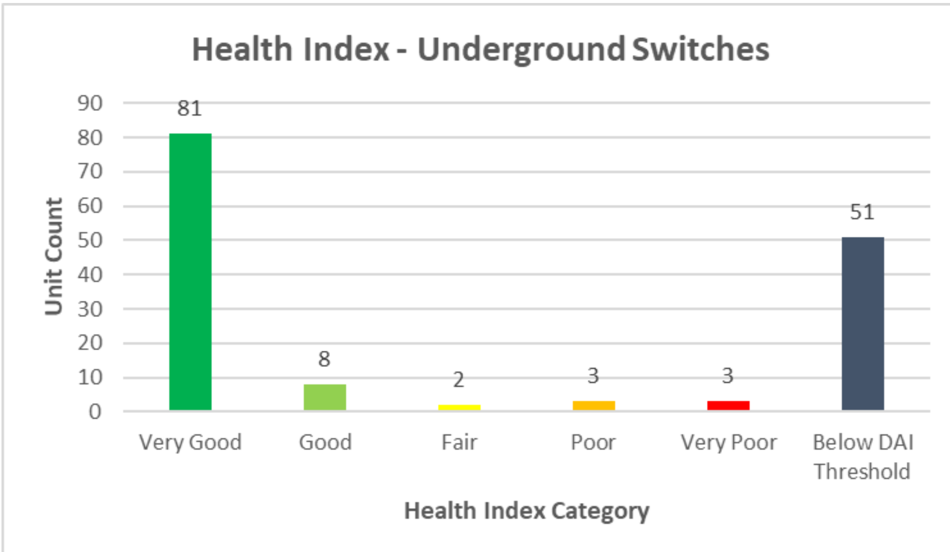
PUC owns 148 underground switches within its service territory. The installations dates are known for the entire underground switch population. Figure 4-21 presents the age distribution for underground switches to show an approximate representation of the age distribution.

Figure 4-21: Underground Switch Age Demographics



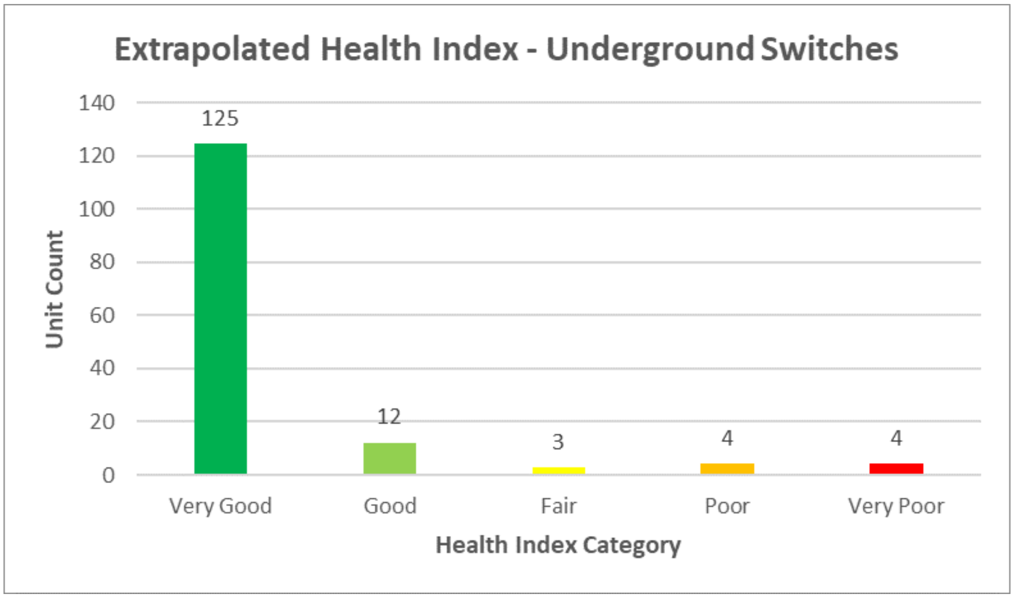
PUC's maintenance records and nameplate information were used to calculate the HI results based on the criteria provided in Table 4-6. A valid HI was calculated for 66% of the underground switches, as shown in Figure 4-22.

Figure 4-22: Underground Switch HI Results



To complete the full analysis, the HI for the remaining population was extrapolated based on the HI distribution of the asset population with a valid HI score. As shown in Figure 4-23, most of the switches are in Very Good or Good condition, with less than 8% of the switches in Fair condition or worse.

Figure 4-23: Extrapolated Underground Switch HI Results



4.1.9 Distribution Switchgear

Distribution switchgears provide the required level of operating flexibility for the underground system. They are employed for controlling, regulating, and isolating the electrical circuit in the underground distribution system. During a fault, switchgear can be used to isolate and the faulted section and restore power to unfaulted parts of the system. Switchgear can also de-energize equipment during maintenance and testing. In some cases, they are used to transfer power manually or automatically in distribution circuits from a preferred source to an alternate source. The HI for distribution switchgears is calculated by considering a combination of end-of-life criteria summarized in Table 4-7.

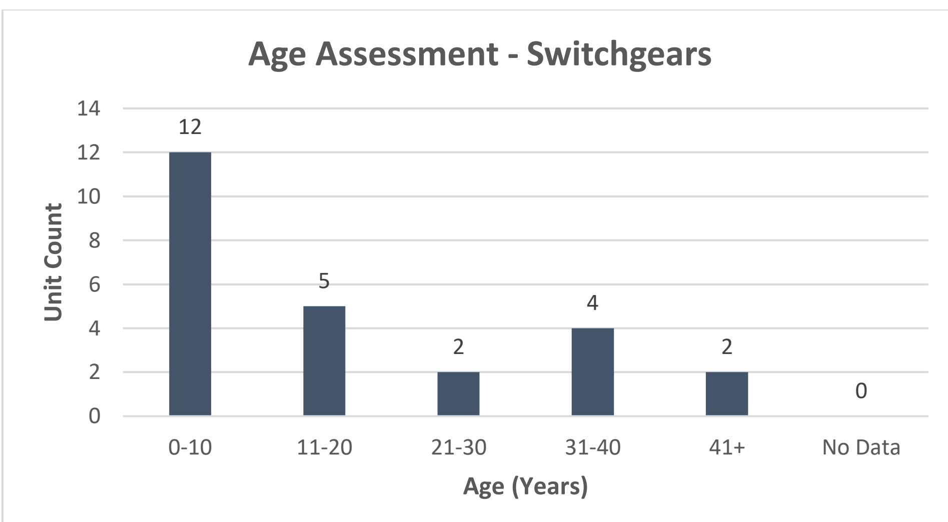
Table 4-7: Switchgear HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Pad condition	4	A,B,C,D,E	4,3,2,1,0	16
IR Scan	1	A,B,C,D,E	4,3,2,1,0	4
Barrier boards	3	A,B,C,D,E	4,3,2,1,0	12
Terminations	2	A,B,C,D,E	4,3,2,1,0	8
Enclosure (excluding pad)	3	A,B,C,D,E	4,3,2,1,0	12
Internal components	4	A,B,C,D,E	4,3,2,1,0	16
Insulators	2	A,B,C,D,E	4,3,2,1,0	8
Switch mechanism	2	A,B,C,D,E	4,3,2,1,0	8
			Total Score	**100**

IR scan results represent an important condition parameter for condition assessment of distribution switchgear since they identify hotspots (i.e. high temperatures) on the asset. Assets operating continuously at high temperatures can cause accelerated degradation of the asset and may experience premature failure. It is assumed and confirmed by PUC that switchgear exhibiting high temperatures have since been corrected.

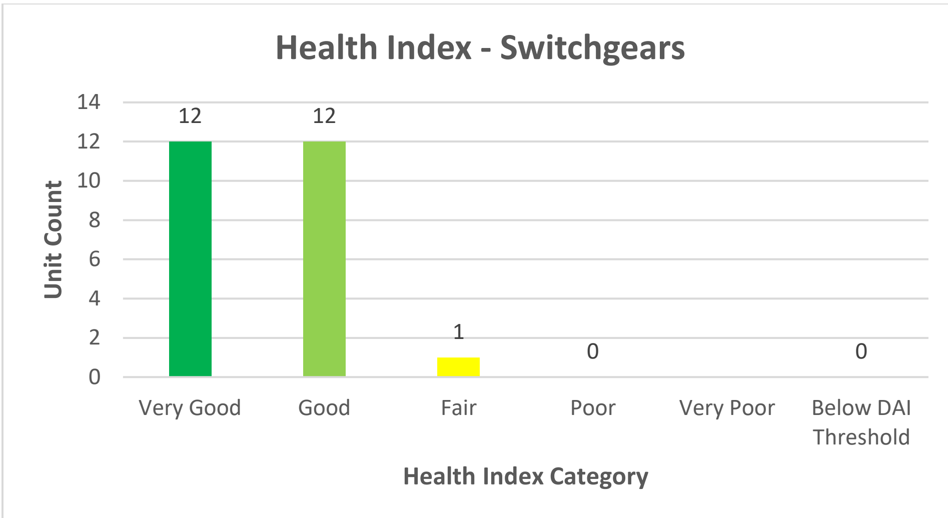
PUC owns 25 switchgear units within its service territory. Figure 4-24 presents the age distribution for PUC's switchgear.

Figure 4-24: Switchgear Age Demographics



The overall switchgear HI distribution is presented in Figure 4-25. All the switchgears are in Good or Very Good condition other than one in Fair condition.

Figure 4-25: Switchgear HI Results

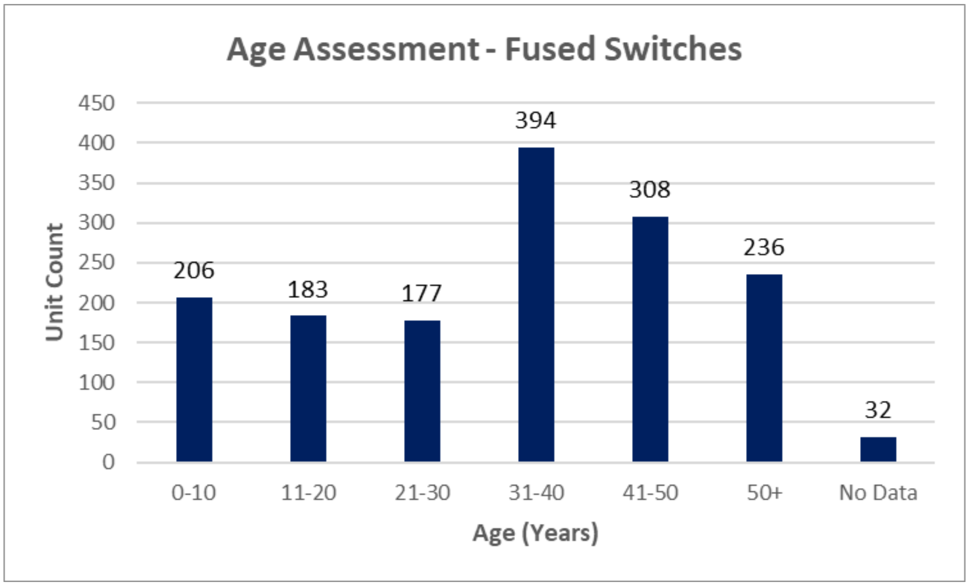


4.1.10 Fused Switches (Cut-outs)

Fused switches (also called cut-outs) provide over-current protection during overload conditions or short circuits. Some fused switches are also designed to provide load-breaking capabilities via the fuse holder.

PUC owns a total of 1536 fused switches within its service territory. Fused switches are assumed to have the same age distribution as wood poles. The TUL for this asset class is 45 years. The age demographic indicates this is an aging asset population – given that 27% of the population is currently past its TUL and 10% will reach TUL in the next 5 years. Figure 4-26 presents the age distribution for fused switches.

Figure 4-26: Fused Switches Age Demographics

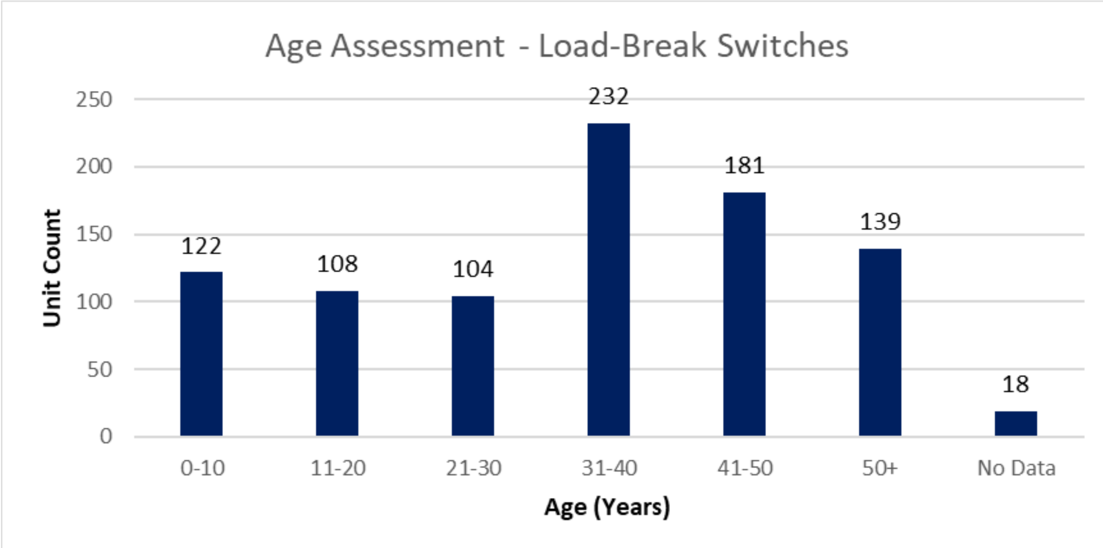


4.1.11 Load-Break Switches

Load-break switches are solid-blade devices used to make or break load during planned and unplanned switching operations. These switches can be installed as single-phase, in-line devices or three-phase group-operated devices.

PUC owns a total of 905 load-break switches within its service territory. Load-break switches are assumed to have the same age distribution as wood poles. The TUL for this asset class is 45 years. The age demographic indicates this is an aging asset population – given that 27% of the population is currently past its TUL and 10% will reach TUL in the next 5 years. Figure 4-27 presents the age distribution for load-break switches.

Figure 4-27: Load-Break Switches Age Demographics



4.2 Station Assets

4.2.1 Power Transformers

Power transformers are key stations assets owned by PUC that are used to step down the voltage from the transmission to sub-transmission systems, or from the sub-transmission system to distribution levels. Computing the HI for a power transformer requires the combination of various end-of-life criteria for its components. Table 4-8 summarizes the HI formulation used for power transformers.

Table 4-8: Power Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Dissolved Gas Analysis	6	A,B,C,D,E	4,3,2,1,0	24
Service Age	10	A,B,C,D,E	4,3,2,1,0	40
Oil Quality	4	A,B,C,D,E	4,3,2,1,0	16
Furan Analysis	3	A,B,C,D,E	4,3,2,1,0	12
Load History	5	A,B,C,D,E	4,3,2,1,0	20
Average Winding Temperature	1	A,B,C,D,E	4,3,2,1,0	4
Transformer Main Tank/ Cabinet and Control Condition	3	A,B,C,D,E	4,3,2,1,0	12
Oil Leaks	3	A,B,C,D,E	4,3,2,1,0	12
Gauges, Gas Pressure Relief and Gas Pressure Relay Condition	1	A,B,C,D,E	4,3,2,1,0	4
Transformer Conservator/ Oil Preservation System Condition	2	A,B,C,D,E	4,3,2,1,0	8
Radiators/ Cooling system	2	A,B,C,D,E	4,3,2,1,0	8
Connectors	1	A,B,C,D,E	4,3,2,1,0	4
Transformer Foundation/ Support Steel	1	A,B,C,D,E	4,3,2,1,0	4
Grounding Condition	1	A,B,C,D,E	4,3,2,1,0	4
Bushing head Condition	3	A,B,C,D,E	4,3,2,1,0	12
Bushing Condition	3	A,B,C,D,E	4,3,2,1,0	12
Tap Changer Tank Condition	3	A,B,C,D,E	4,3,2,1,0	12
Tap Changer Tank Leaks	1	A,B,C,D,E	4,3,2,1,0	4
Tap Changer Gaskets, seals, and pressure relief	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	5	A,B,C,D,E	4,3,2,1,0	20
			Total Score	240

By performing DGA, it is possible to identify internal faults, partial discharge ("PD"), low-energy sparking, severe overloading, and overheating in the insulating medium. Insulation power factor measurements are an important source of data to monitor transformer and bushing conditions. Lower scores for one or a combination of these condition parameters strongly indicate progressed degradation of the asset, hence their larger weights.

Power transformer peak loading is a good indication of loss of insulation life. The rate of insulation degradation is directly related to the operating temperature which is directly related to transformer loading levels. The peak loading level of the transformers is expressed in a percentage of the nameplate rating. PUC collects the substation load history monthly, recording the monthly peak.

PUC owns a total of thirty-four power transformers, eight of which are located in transmission stations ("TS"), TS1 and TS2. Figure 4-28 and Figure 4-29 present the age profile of power transformers in-service.

Figure 4-28: Substation Power Transformer Age Demographics

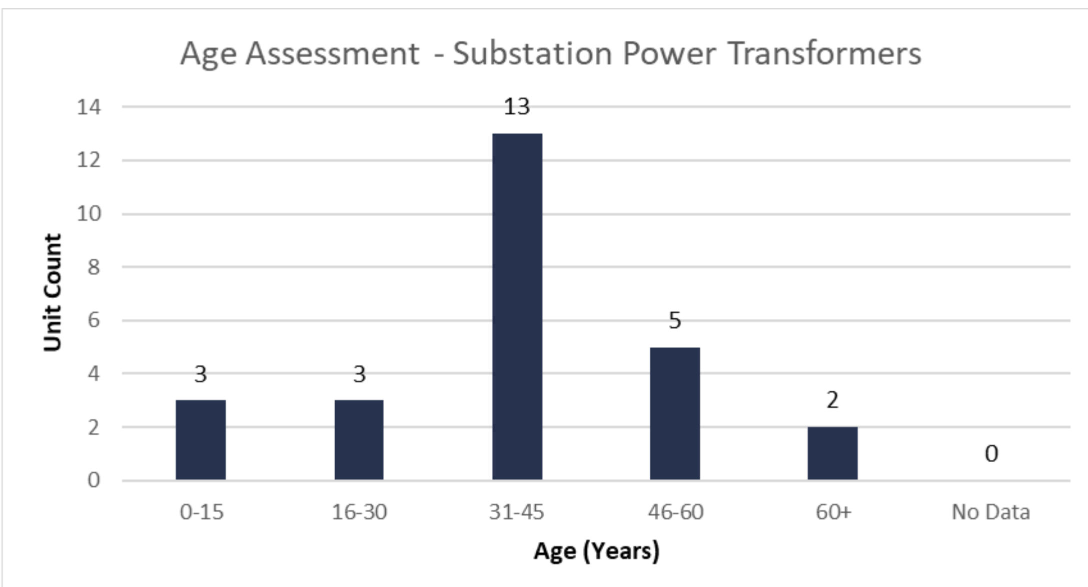
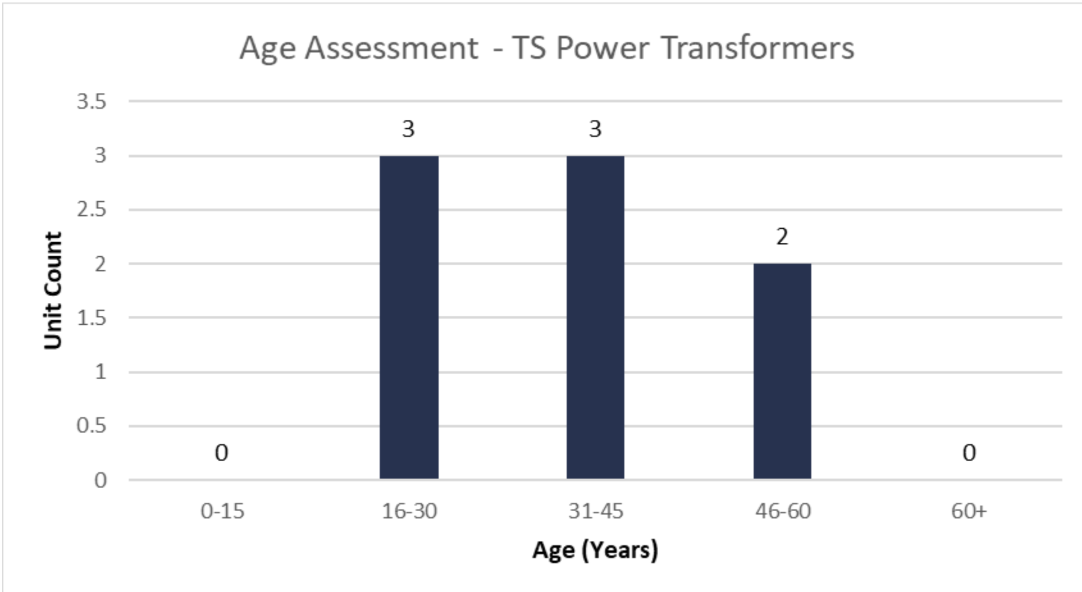


Figure 4-29: TS Power Transformer Age Demographics



PUC's power transformer inspections, test results, and loading history were used to calculate the HI based on the criteria provided in Table 4-8. The HI distributions for in-service power transformers are presented in Figure 4-30 and Figure 4-31 . Most power transformers lie between Fair and Very Good, while one transformer; Sub20_T1 is in Poor condition.

Figure 4-30: Substation Power Transformer HI Results

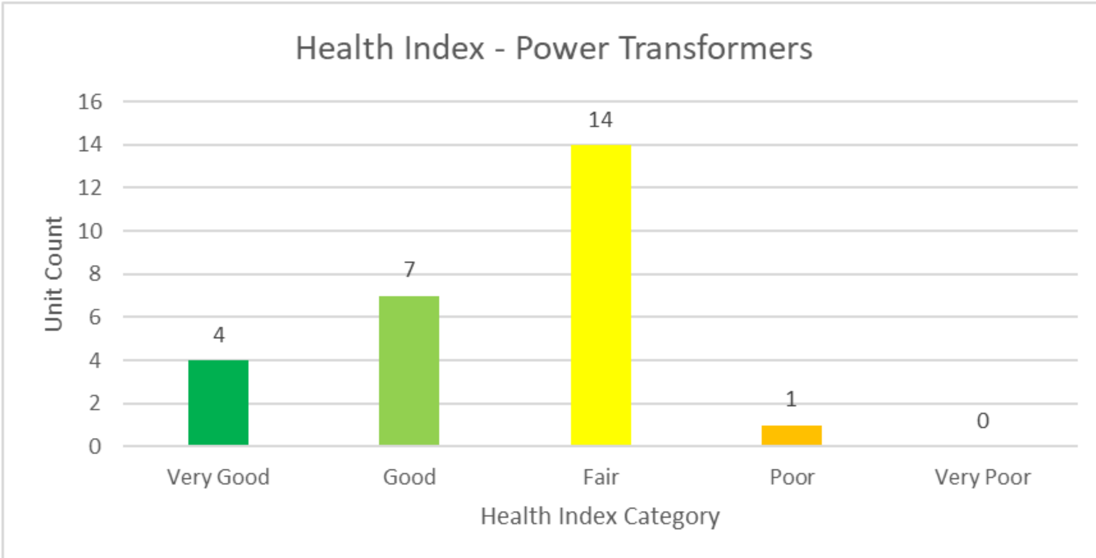
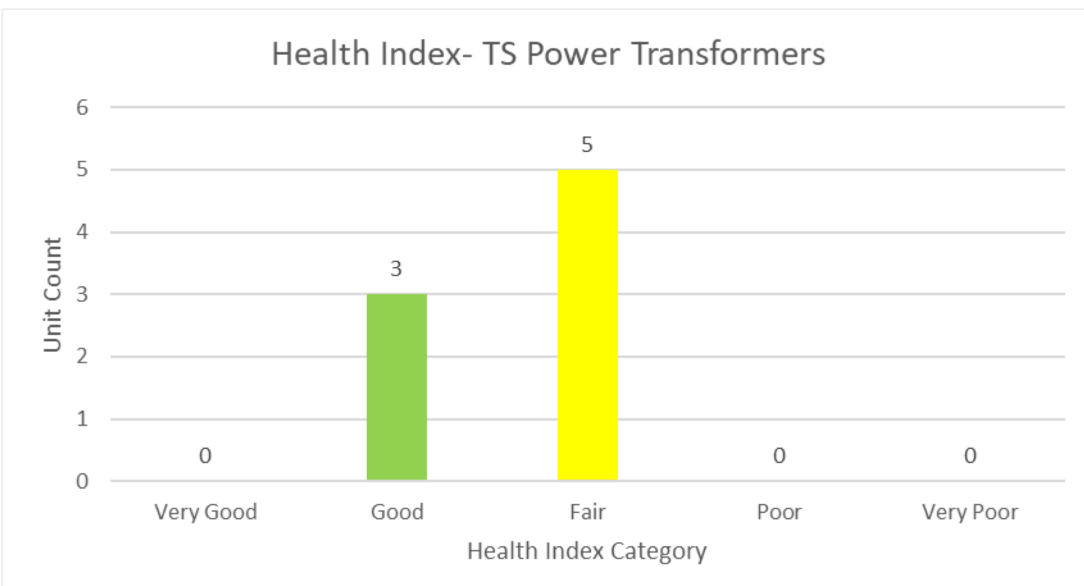


Figure 4-31: TS Power Transformer HI Results



In order to comprehend which assets have a high risk of failure, Table 4-9 below lists all the condition parameters that ranked at a "D" or an "E"; poor or very poor condition in the Health Index.

Table 4-9 "Red Flags" in Power Transformers

Asset ID	D Score	E Score	HI Score
Sub1_T1	Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks, Transformer Conservator/Oil Preservation System Condition	Service Age	59%
Sub 2_T3	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Transformer Conservator/Oil Preservation System Condition	Oil leaks	57%
Sub2_T4	Service Age, Transformer Main Tank/ Cabinet and Control Condition Transformer Conservator/Oil Preservation System Condition	--	63%
Sub4_T2	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks, Transformer Conservator/Oil Preservation System Condition	--	64%
Sub5_T1	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks, Transformer Conservator/Oil Preservation System Condition	--	65%
Sub5_T2	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks	--	64%
Sub11_T3	Service Age, IR Scan	--	62%

Asset ID	D Score	E Score	HI Score
Sub11_T4	Transformer Main Tank/ Cabinet and Control Condition, IR Scan	--	65%
Sub12_T4	Service Age	--	69%
Sub18_T1	Service Age, Oil Leaks,	--	63%
Sub18_T2	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks	--	57%
Sub19_T1	Transformer Main Tank/ Cabinet and Control Condition, IR Scan	--	75%
Sub19_T2	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks, IR Scan	IR Scan	59%
Sub20_T1	Service Age, Transformer Main Tank/ Cabinet and Control Condition, IR Scan	--	45%
Sub20_T2	Transformer Main Tank/ Cabinet and Control Condition, IR Scan	--	65%
Sub21_T2	DGA	--	73%
TS1_SM1	IR Scan	--	77%
TS1_SM2	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Transformer Conservator/Oil Preservation System Condition	IR Scan	63%
TS1_SM3	Service Age, Transformer Main Tank/ Cabinet and Control Condition,	IR Scan	55%

Asset ID	D Score	E Score	HI Score
	Transformer Conservator/Oil Preservation System Condition		
TS1_SM4	Transformer Main Tank/ Cabinet and Control Condition	IR Scan	62%
TS2_TA1	Transformer Main Tank/ Cabinet and Control Condition	IR Scan	62%
TS2_TA2	Transformer Main Tank/ Cabinet and Control Condition	--	70%
TS2_TA3	Transformer Main Tank/ Cabinet and Control Condition	--	71%
TS2_TA4	Transformer Conservator/Oil Preservation System Condition	--	76%

4.2.2 Medium-Voltage Switchgear

Medium-voltage switchgear in PUC's substations operate at 34.5 kV, 12.47 kV, or 4.16 kV. They contain switching devices, circuit breakers, and measurement and control devices. Their functions are:

(a) To provide switching capability on the low or high side of the substation power transformers; and/or
(b) To protect feeders, transformers, and other equipment by opening the circuit under fault conditions.

PUC owns air magnetic and vacuum circuit breakers within switchgears operating at 12.47 kV. Air-magnetic breakers employ the magnetic effect of the current in their design, by forcing the electric arc produced during opening on the contacts into an arc chute. The arc chute causes elongation of the arc path and allows cooling, splitting and eventual extinction of the arc. In a vacuum circuit breaker, vacuum interrupters are employed to make or break load or fault current. Upon separation of the contacts, the current initiates a metal vapor arc discharge and flows through the plasma until the next current zero.

Computing the HI of a switchgear considers end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The HI for medium-voltage substation switchgear is calculated by considering a combination of test results, service age, number of operations, and visual inspections as summarized in Table 4-10.

Table 4-10 Medium-Voltage Switchgear HI Formulation

Condition Parameter	Type	Weight	Ranking	Numerical Grade	Max Score
Insulation Resistance	All	4	A,B,C,D,E	4,3,2,1,0	16
Contact Resistance	All	2	A,B,C,D,E	4,3,2,1,0	8
Operations Count	All	3	A,B,C,D,E	4,3,2,1,0	12
Minimum Close Voltage Test	All	1	A,B,C,D,E	4,3,2,1,0	4
Minimum Trip Voltage Test	All	1	A,B,C,D,E	4,3,2,1,0	4
Maintenance Results	All	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	All	4	A,B,C,D,E	4,3,2,1,0	16
IR Scans	All	4	A,B,C,D,E	4,3,2,1,0	16
Service Age	All	6	A,B,C,D,E	4,3,2,1,0	24
				Total Score	**112**

Service age is given the highest weight as this equipment deteriorates more over time. Maintenance tests such as the insulation resistance test and IR inspection are also weighted the highest because they are the best indicator of the asset's condition and performance.

PUC owns 30 medium-voltage switchgears within its substations operating at 4.16 kV, 12.47 kV, and 34.5 kV. The age of the switchgears is known for 93% of the population. Figure 4-32 to Figure 4-34 presents the age distribution for switchgear by voltage level.

Figure 4-32: 4.16kV Substation Switchgear Age Demographics

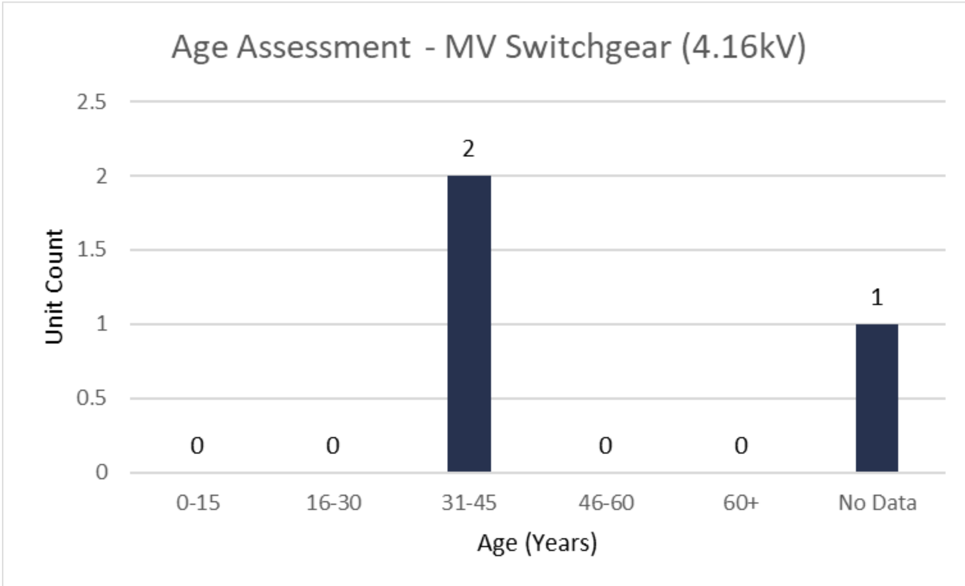


Figure 4-33: 12.47kV Substation Switchgear Age Demographics

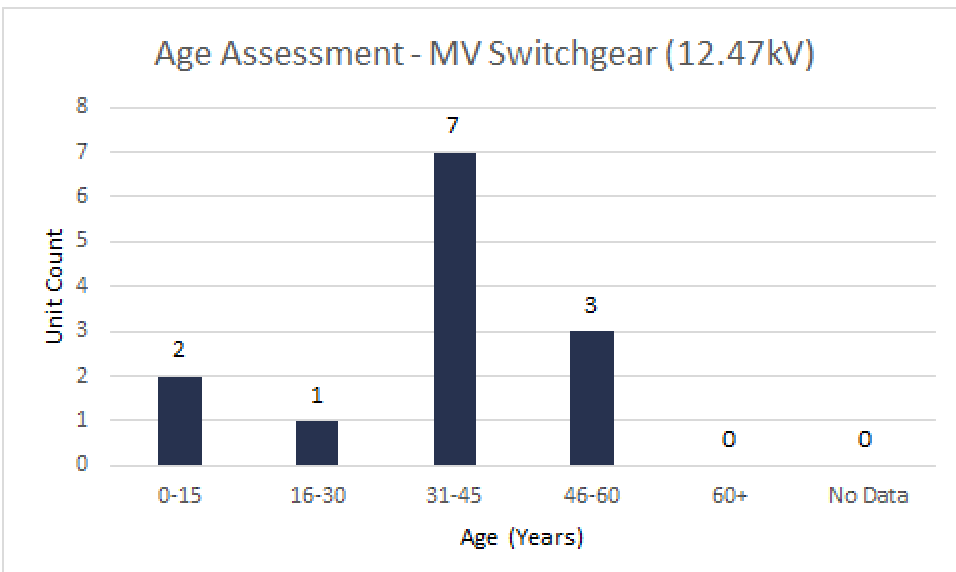
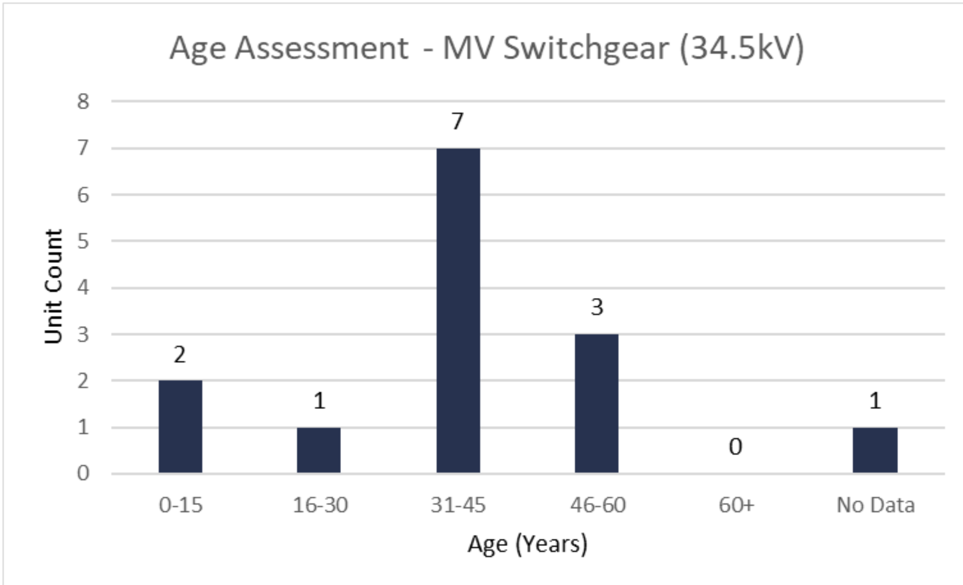
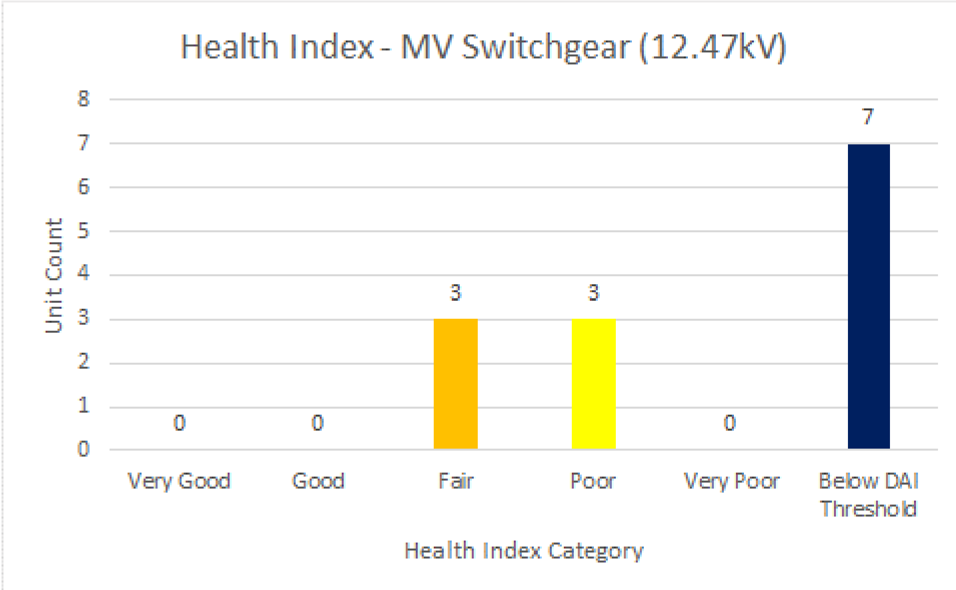


Figure 4-34: 34.5kV Substation Switchgear Age Demographics



A valid Health Index was calculated only for 12.47-kV switchgear. PUC's maintenance records, operation data, and visual inspections were used to calculate the HU based on the criteria provided in Figure 4-35. HI is known for 43% of the total population, all assets with a valid HI are in Fair or Poor condition, indicating the need for investment.

Figure 4-35: Medium-Voltage Switchgear HI Results



In order to comprehend which assets, have a high risk of failure, Table 4-11 below lists all the condition parameters that ranked at a "D" or an "E"; poor or very poor condition in the Health Index for the circuit breakers within the switchgears.

Table 4-11: "Red Flags" in MV Circuit Breakers

Asset ID	D score	E Score	HI
1-R1	Insulation Resistance, Contact Resistance	Minimum Close Voltage Test, Maintenance	45%
12-11	--	Contact Resistance, Minimum Close Voltage Test, Maintenance	54%
12-12	--	Contact Resistance, Minimum Close Voltage Test, Maintenance	54%
12-13	--	Contact Resistance, Minimum Close Voltage Test, Maintenance	54%
12-14	--	Contact Resistance, Minimum Close Voltage Test, Maintenance	54%

Asset ID	D score	E Score	HI
12-R3	Visual Inspection	Contact Resistance, Minimum Close Voltage Test, Maintenance	50%
12-R4	Visual Inspection	Contact Resistance, Minimum Close Voltage Test, Maintenance	50%
12-TB	--	Contact Resistance, Minimum Close Voltage Test, Maintenance, IR Scans	46%
13-01	Contact Resistance, IR Scan	Minimum Close Voltage Test, Minimum Trip Voltage Test	63%
13-02	Contact Resistance, IR Scan	Minimum Close Voltage Test, Minimum Trip Voltage Test	60%
13-03	IR Scan	Contact Resistance, Minimum Close Voltage Test, Minimum Trip Voltage Test	58%
13-04	Contact Resistance, IR Scan	Minimum Close Voltage Test, Minimum Trip Voltage Test	63%
13-R1	IR Scan	Contact Resistance, Minimum Close Voltage Test, Minimum Trip Voltage Test	58%
13-R2	Contact Resistance, IR Scan	Minimum Close Voltage Test, Minimum Trip Voltage Test	60%
15-01	--	Minimum Trip Voltage Test, IR Scan	61%
15-02	--	Minimum Trip Voltage Test, IR Scan	61%
15-03	--	Minimum Trip Voltage Test, IR Scan	61%
15-04	--	Minimum Trip Voltage Test, IR Scan	61%

Asset ID	D score	E Score	HI
15-R1	--	Minimum Trip Voltage Test	69%
15-R2	--	Minimum Trip Voltage Test, IR Scan	61%
18-01	Insulation Resistance, Visual Inspection, Service Age	Contact Resistance, Minimum Trip Voltage Test, IR Scan	35%
18-02	Service Age	Minimum Trip Voltage Test, IR Scan	54%
18-03	Insulation Resistance, Contact Resistance, IR Scan, Service Age	Minimum Trip Voltage Test	44%
18-04	Service Age	Contact Resistance, Minimum Trip Voltage Test, IR Scan	50%
18-R1	Service Age	Minimum Trip Voltage Test, IR Scan, Maintenance	44%
18-R2	IR Scan, Service Age	--	63%
20-01	Contact Resistance, Maintenance, IR Scans	--	56%
20-02	Maintenance	Contact Resistance, IR Scan	51%
20-03	Maintenance, IR Scan	Contact Resistance	55%
20-04	--	Contact Resistance, IR Scan	65%
20-R1	Maintenance	Contact Resistance, IR Scan	51%
20-R2	--	Contact Resistance, IR Scan	59%

4.2.3 34.5-kV TS Circuit Breakers

Outdoor circuit breakers are stand-alone electrical devices that operate automatically during a fault. It protects other electrical assets from damage due to short-circuit current. It operates when a fault is detected and can be programmed to automatically restore the connection once the fault is cleared or can be reset manually based on the severity of the fault.

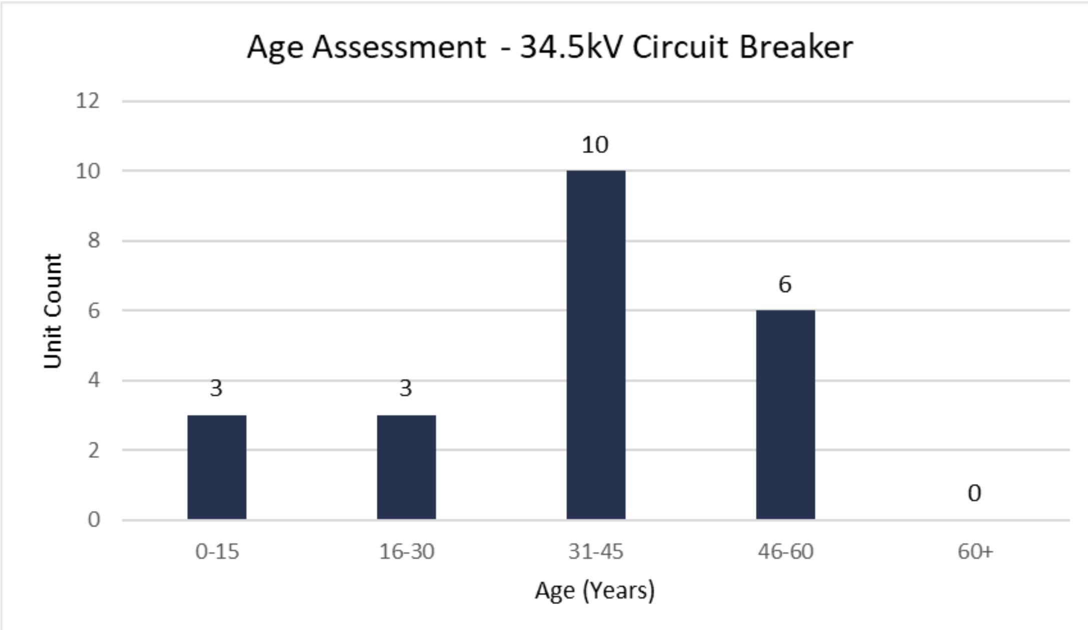
PUC owns twenty-two circuit breakers operating at 34.5 kV: seventeen oil circuit breakers, three vacuum circuit breakers, and two SF6 circuit breakers, located at TS1 and TS2. Table 4-12 summarizes the methodology to generate the Health Index for High Voltage circuit breakers.

Table 4-12: 34.5 kV TS Circuit Breaker HI Formulation

Condition Parameter	Type	Weight	Ranking	Numerical Grade	Max Score
Insulation Resistance	All	4	A,B,C,D,E	4,3,2,1,0	16
Contact Resistance	All	4	A,B,C,D,E	4,3,2,1,0	16
Close Travel Analysis	All	1	A,B,C,D,E	4,3,2,1,0	4
Open Travel Analysis	All	1	A,B,C,D,E	4,3,2,1,0	4
Bushing/support Insulators	All	4	A,B,C,D,E	4,3,2,1,0	16
Tank and mechanism box	All	4	A,B,C,D,E	4,3,2,1,0	16
Overall breaker condition	All	4	A,B,C,D,E	4,3,2,1,0	16
Foundation/Support Steel/Grounding	All	3	A,B,C,D,E	4,3,2,1,0	12
Oil Leaks	Oil	2	A,B,C,D,E	4,3,2,1,0	8
Service Age	All	4	A,B,C,D,E	4,3,2,1,0	16
IR Scans	All	4	A,B,C,D,E	4,3,2,1,0	16
				Total Score	**140**

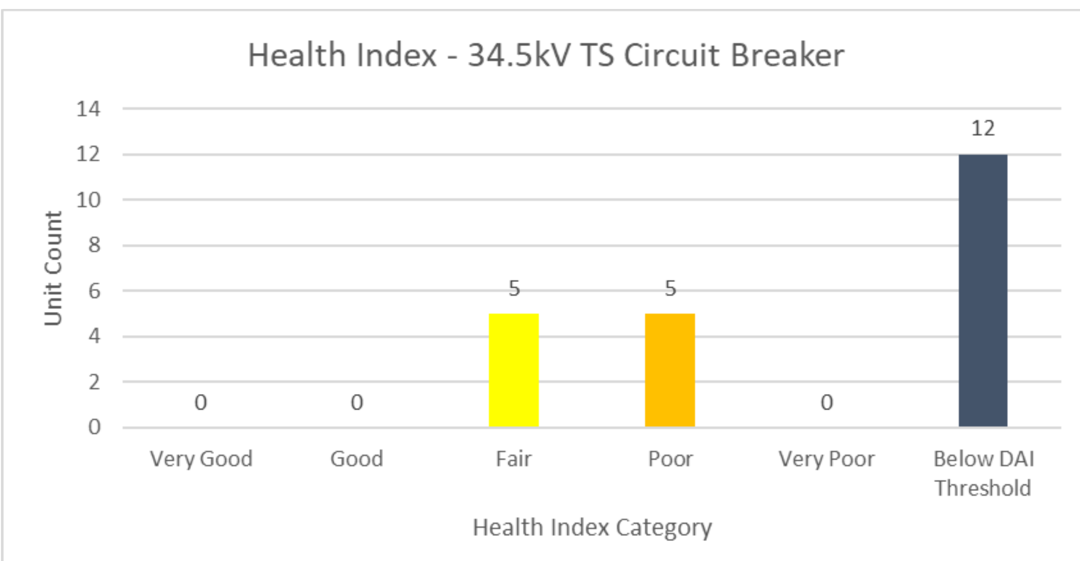
The installation date is known for the entirety of the population. The age distribution for 34.5-kV circuit breakers is shown in Figure 4-36.

Figure 4-36: 34.5-kV TS Circuit Breaker Age Demographics



The HI distribution for in-service 34.5kV circuit breakers is presented in Figure 4-37. The HI is known for 45% of the population and their condition lies in either Fair or Poor condition.

Figure 4-37: 34.5-kV TS Circuit Breaker HI Results



In order to comprehend which assets have a high risk of failure, Table 4-13 below lists all the condition parameters that ranked at a "D" or an "E"; Poor or Very Poor condition in the Health Index.

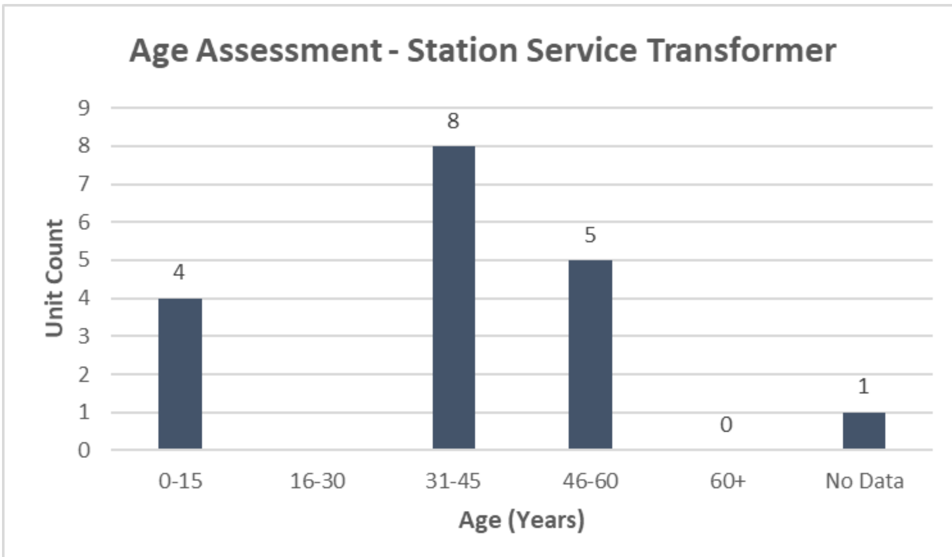
Table 4-13: "Red Flags" in 34.5-kV TS Circuit Breakers

Asset ID	D score	E Score	HI
TS1-SM4	Insulation Resistance, Contact Resistance, Tank & Mechanism Box	IR Scan	47%
TS1-SM5	Insulation Resistance, Tank & Mechanism Box	Contact Resistance, IR Scan	44%
TS1-SM7	Contact Resistance, Tank & Mechanism Box, Service Age	Close Travel Analysis, IR Scan	51%
TS1-SM9	Contact Resistance, Service Age	IR Scan	58%
TS1-SM11	Contact Resistance, Service Age	IR Scan	51%
TS2-TA1	Insulation Resistance, Contact Resistance, Tank & Mechanism Box, Overall Breaker Condition, Oil Leaks, IR Scan	--	44%
TS2-TA2	Contact Resistance, IR Scan	Insulation Resistance	50%
TS2-TA3	Contact Resistance, IR Scan, Tank & Mechanism Box	Insulation Resistance	46%
TS2-TA6	Contact Resistance, IR Scan, Tank & Mechanism Box	--	56%
TS2-TA7	Contact Resistance, Tank & Mechanism Box, Oil Leaks	IR Scan	47%

4.2.4 Station Service Transformers

Station service transformers supply power to auxiliary equipment in the station including the charger for station DC and batteries, SCADA and communications infrastructure, lights, equipment and building heaters and security systems. Often, these assets can be encased in enclosures and are difficult to assess or read the nameplate without taking an outage. PUC owns eighteen station service transformers. Installation date is known for most of the population. Due to the unavailability of inspection data for station service transformers, health indices were not calculated. The age distribution of station service transformer is illustrated in Figure 4-38.

Figure 4-38: Station Service Transformer Age Demographics



4.2.5 Battery Banks and Chargers

The battery system provides backup power to essential station functionalities such as lighting, communication, and protection/control equipment in the event of a loss of supply to the station. The main components of the battery system are the charger and the battery bank which is comprised of several battery cells in series.

The HI formulations for battery banks and chargers are combined based on age, test results, and visual inspection results. Age provides insight into the remaining useful life of the asset based on the typical useful lives of DC systems seen across the industry. Batteries also operate based on a determinate chemical process, which has a known lifetime and useful duration. Table 4-14 summarizes the methodology to generate the Health Index for station batteries.

Table 4-14: Station Battery and Charger HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age of Battery	4	A,B,C,D,E	4,3,2,1,0	16
Age of Charger	4	A,B,C,D,E	4,2,0	16
Electrolyte Level	3	A,C,E	4,2,0	12
Connections	2	A,B,C,D	4,3,2,1	8
Straps/ Cables	2	A,B,C,D	4,3,2,1	8
Battery Cells and trays/tracks	2	A,B,C,D	4,3,2,1	8
Individual Cell Voltage	1	A,B,C,D,E	4,3,2,1,0	4
Internal & Intercell Resistance	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**84**

PUC owns seventeen batteries and chargers within its stations. The asset installation years are known for all battery banks and chargers. Figure 4-39 to Figure 4-42 present the age distributions for station battery banks and chargers.

Figure 4-39: Substation Battery Banks Age Demographics

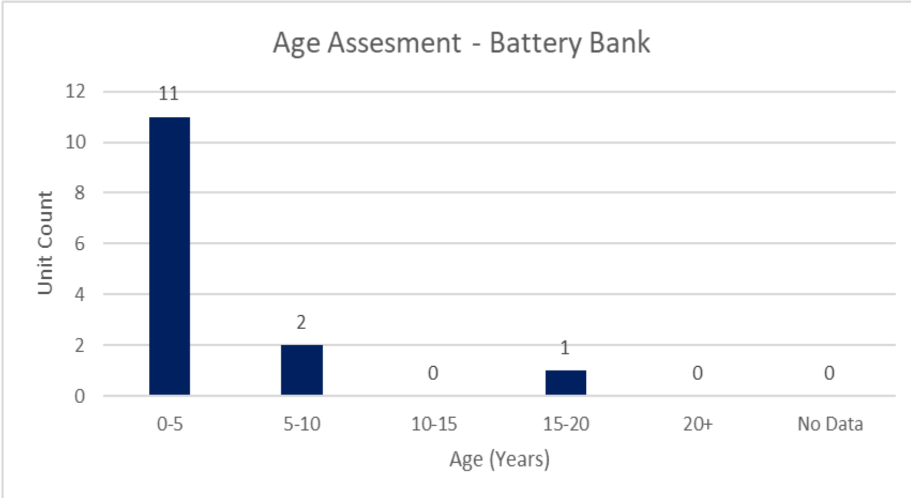


Figure 4-40: TS Battery Bank Age Demographics

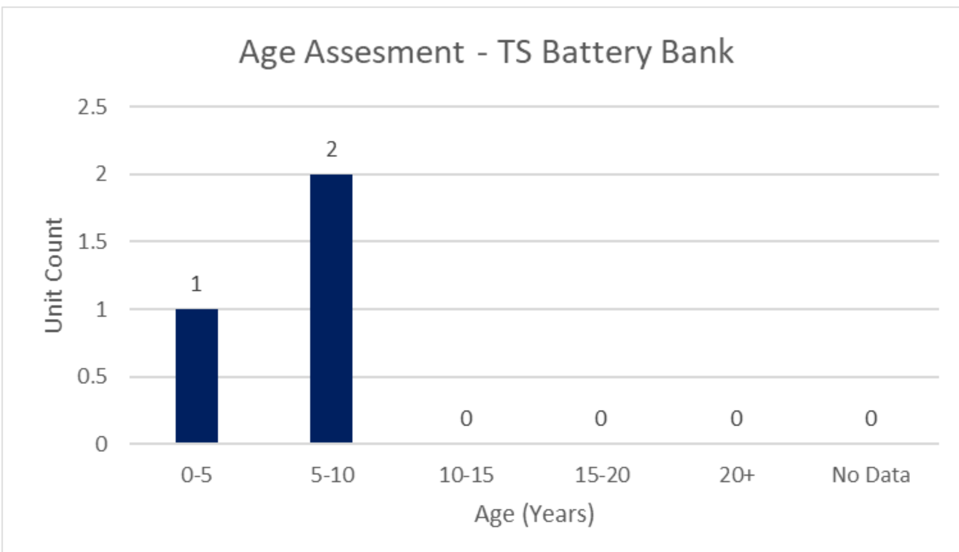


Figure 4-41: Substation Battery Charger Age Demographics

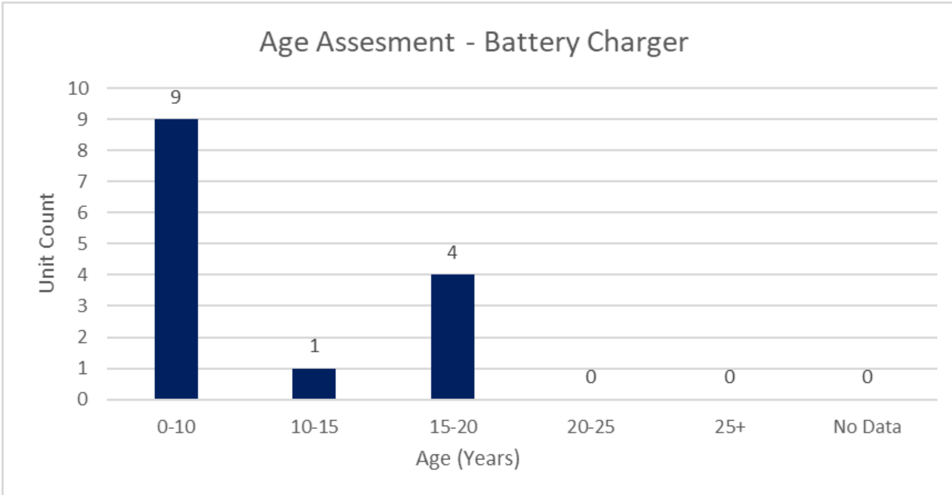
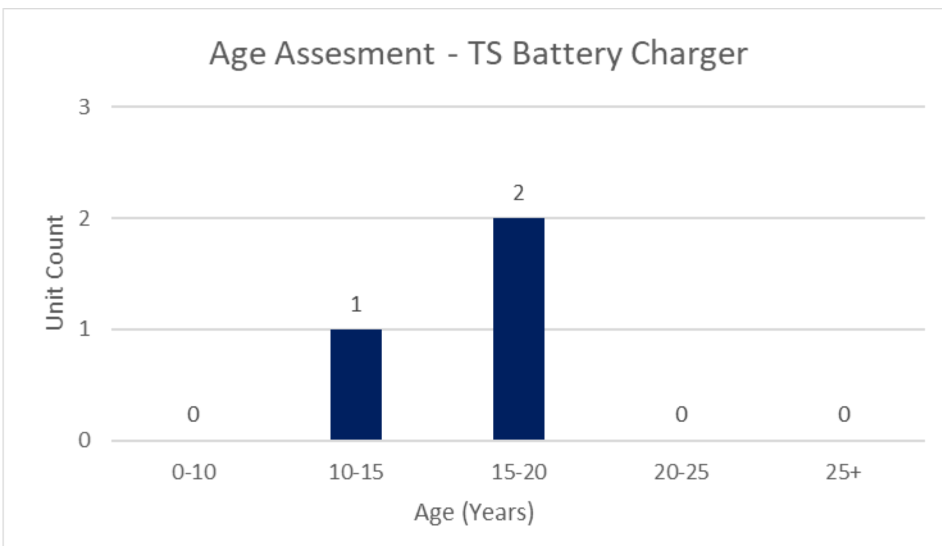


Figure 4-42: TS Battery Charger Age Demographics



The maintenance test results and visual inspection information for PUC's battery banks and chargers were used to calculate the HI based on the criteria listed in Table 4-14. The HI distributions for station batteries are presented in Figure 4-43 and Figure 4-44. Most batteries were in Good or Very Good condition.

Figure 4-43: Substation Battery HI Results

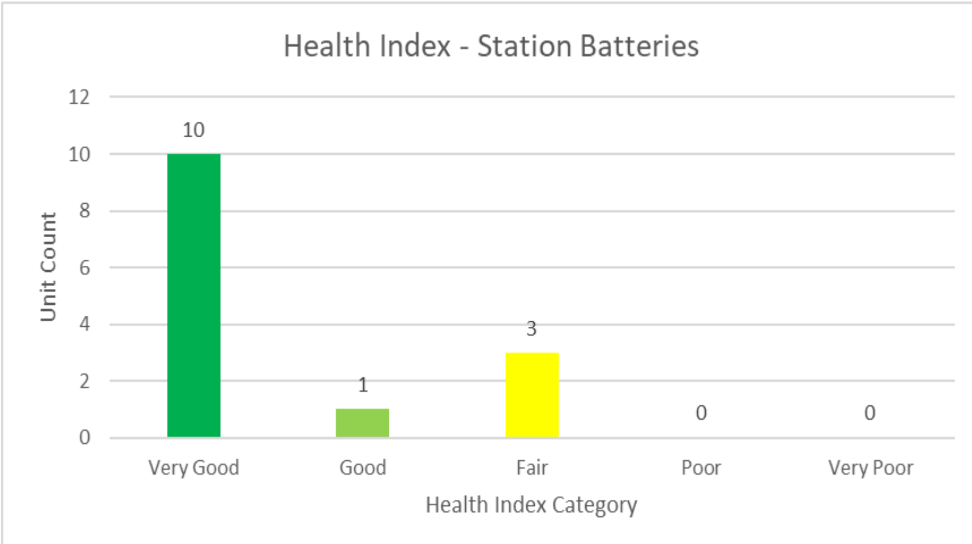
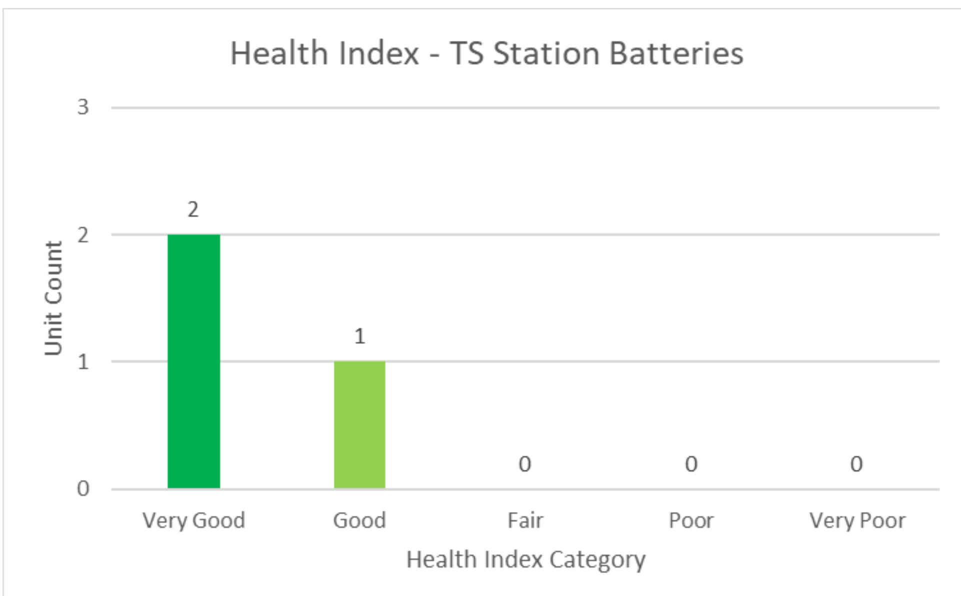


Figure 4-44: TS Station Battery HI Results



4.2.6 Station Buildings

The primary function of buildings at stations is to provide a suitable environment for electrical equipment or to serve as a base for administrative and service work. To achieve this, they must be weatherproof. Interaction with the environment poses a continuous threat to the integrity of buildings. Regular preventative maintenance, undertaking minor repairs, painting, etc., are essential to ensure the long-term viability and integrity of buildings.

For buildings containing electrical equipment the critical factor is preventing water ingress. Roof maintenance is therefore the most significant issue for transmission buildings. Regular preventative maintenance with occasional major refurbishment of roofs, windows and doors should enable buildings to have long lifetimes. It is likely that for well-maintained buildings end-of-life will be for operational, non-condition, reasons.

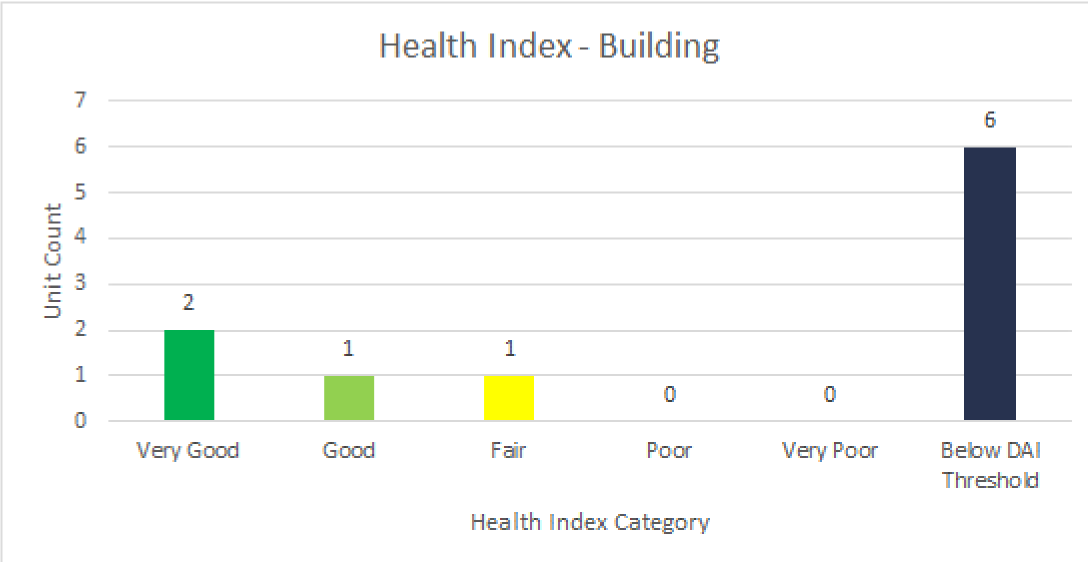
PUC owns a total of ten substation buildings and their visual inspection criteria used to develop its health index is shown below in Table 4-15.

Table 4-15: Station Building HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Roof Condition	4	A,B,C,D,E	4,3,2,1,0	16
Wall Condition	4	A,B,C,D,E	4,3,2,1,0	16
Doors/Windows/Louvres	2	A,B,C,D,E	4,3,2,1,0	8
Floors/Foundations	4	A,B,C,D,E	4,3,2,1,0	16
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**72**

Visual inspections were used to calculate the HI based on the criteria listen in Table 4-15. The HI distribution for station buildings is presented in Figure 4-45.

Figure 4-45: Station Building HI Results



4.2.7 Station Fences

The integrity of fences, contribute the safety of the station and the performance of the assets therein. Fences protects the public from hazardous electrical contacts, and to protect facilities against intrusion and vandalism.

The HI for Station Fences is calculated by using visual inspection results. Table 4-16 summarizes the HI formulation for station facilities. The condition parameters focus on the physical condition of the fence since a grounding study was not part of the scope of this assessment. PUC should consider a grounding study for its TS and substations in the future, particularly if there are issues of copper theft.

Table 4-16 – Station Fences HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Grounding	2	A,C,E	4,2,0	8
Fence Bottom Gap	3	A,C,E	4,2,0	12
Gate Condition/ Operation	3	A,C,E	4,2,0	12
Barbed Wire	3	A,C,E	4,2,0	12
Fence Fabric	4	A,C,E	4,2,0	16
Slanted or frost-affected fence posts	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**72**

There are twelve station fences within PUC's service territory: ten at substations and two at TS. Visual Inspections were used to calculate the HI based on the criteria listed in Table 4-16. The HI distributions for station fences are presented in Figure 4-46 and Figure 4-47. All the population are in Very Good or Good condition.

Figure 4-46: Substation Fence HI Results

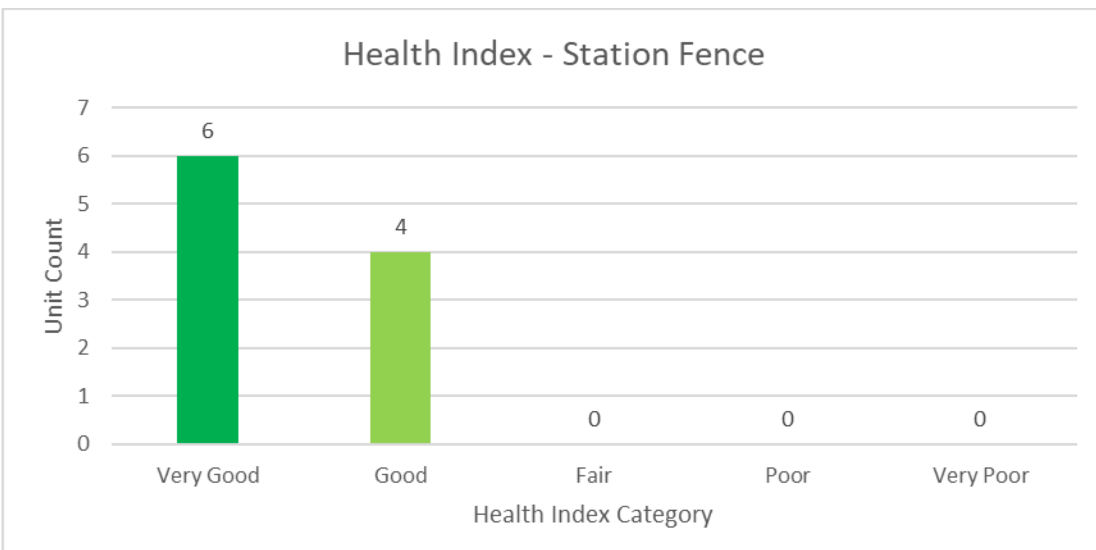
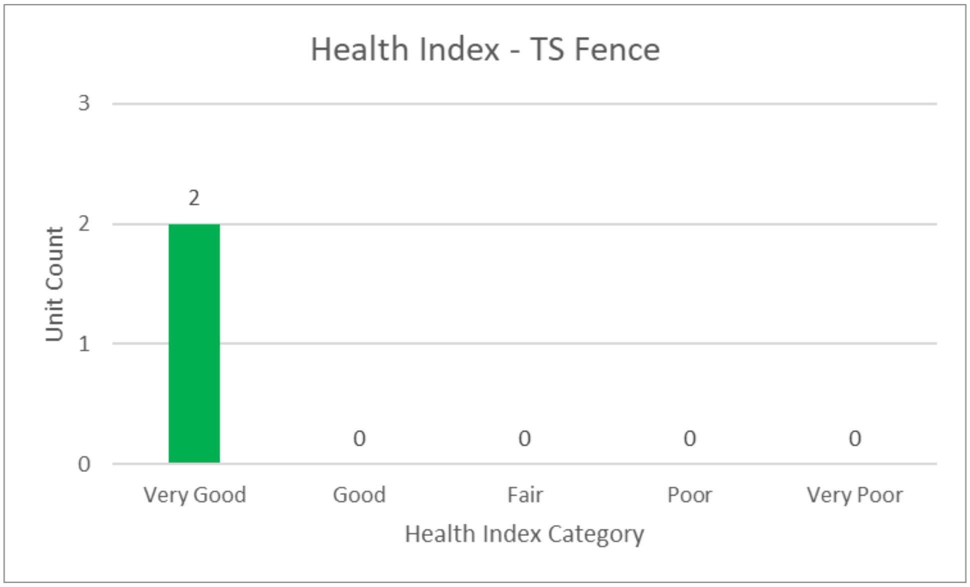


Figure 4-47: TS Fence HI Results



4.2.8 Station Riser Cables

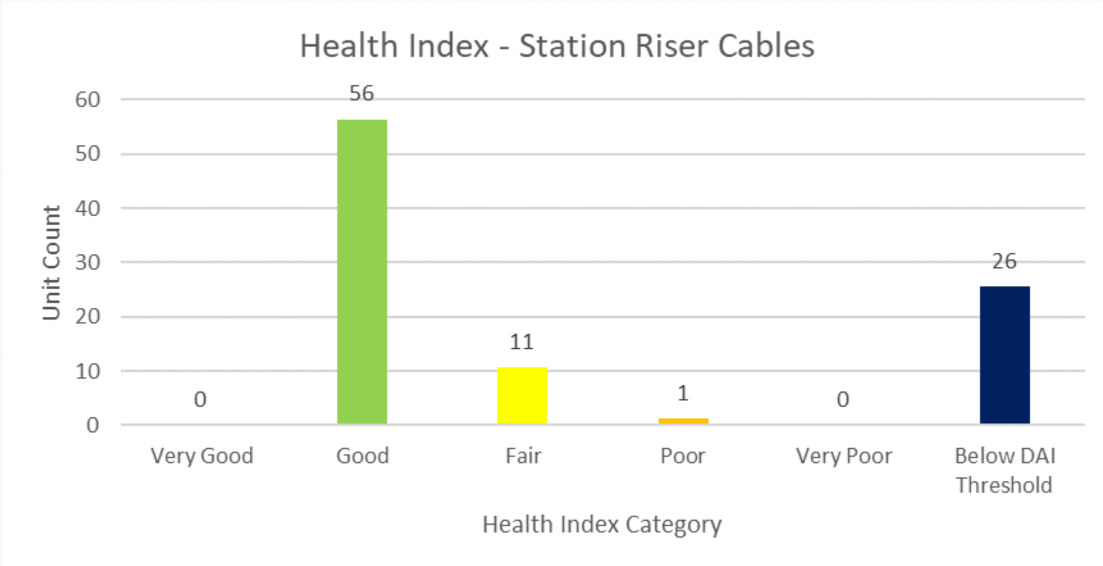
Riser cables provide a transition from underground cables to overhead lines at the egress of the station. They are critical since they carry the entire load of the feeder.

Table 4-17: Station Riser Cable HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
IR Scans	1	A,B,C,D,E	5,4,3,2,1	5
			Total Score	**5**

PUC owns approximately 94 riser cables within their stations. The HI for station riser cables is calculated by considering the infrared scan assessment. As shown in Figure 4-48 below, a valid HI was calculated for 78% of riser cables with 71% scoring in Fair or Good condition.

Figure 4-48: Station Riser Cable HI Results



4.2.9 115-kV Switches

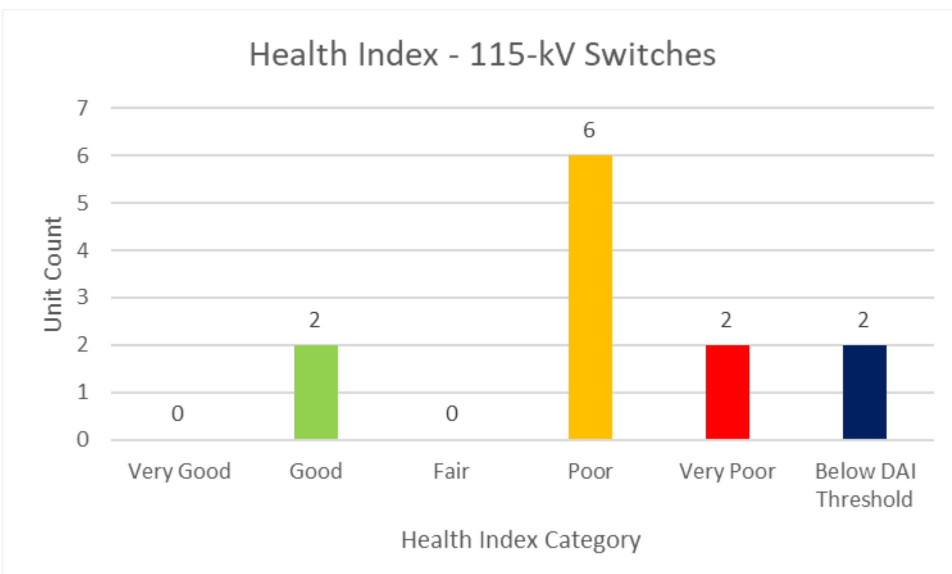
TS switches rated for 115 kV are used to remotely isolate equipment during planned maintenance and unplanned switching operations. The HI for 115-kV switches summarized in Table 4-18 is calculated by considering a combination of visual inspection results and the ability to operate the switches safely.

Table 4-18: 115-kV Switches HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	5	A,B,C,D,E	4,3,2,1,0	20
Operation	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**32**

PUC owns twelve 115-kV switches within its two TS. A valid HI was developed for ten of the 115-kV switches where the remaining two were not inspected. As seen in Figure 4-49, six of the switches are in Poor condition and two are in Very Poor condition. While PUC does operate these switches safely, PUC must isolate the switches which causes inconvenience for customers and is also a costly operation. These switches should be planned for replacement to allow for more efficient operation whilst minimizing impacts felt by customer whilst operating these switches.

Figure 4-49: 115-kV Switches HI Results



5 Conclusions

As Figure 5-1 to Figure 5-3 indicate, most assets across PUC's asset classes analyzed are in Fair condition or better. This can indicate PUC has taken steps in the past to manage their asset health and performance for the benefit of its customers. As with every system, however, there are areas that require PUC's attention in the coming years where asset populations contain material portions of equipment in or approaching Poor condition or worse.

Figure 5-1: Distribution Asset Health Index Results

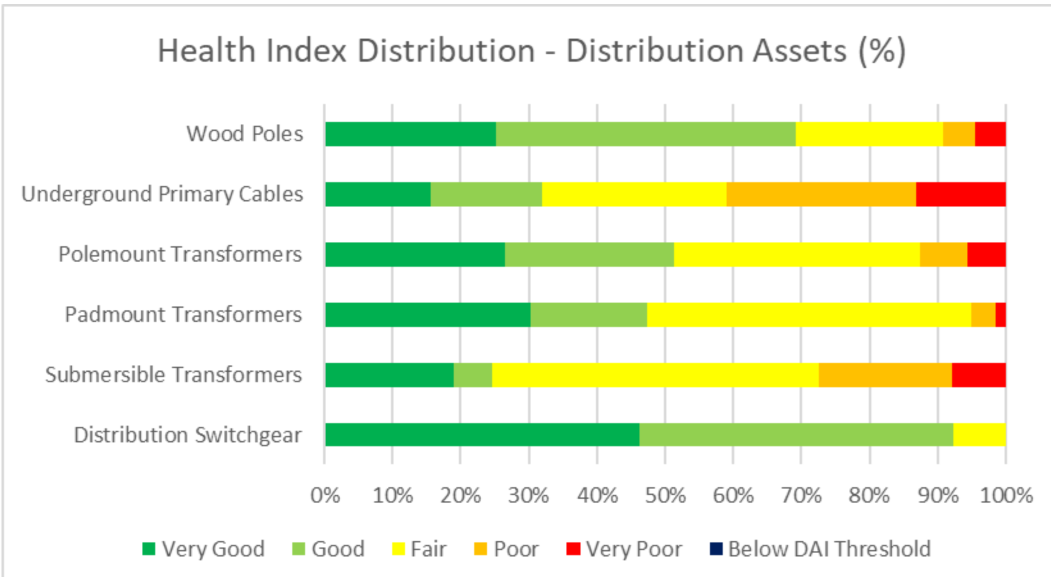


Figure 5-2: Substation Asset Health Index Results

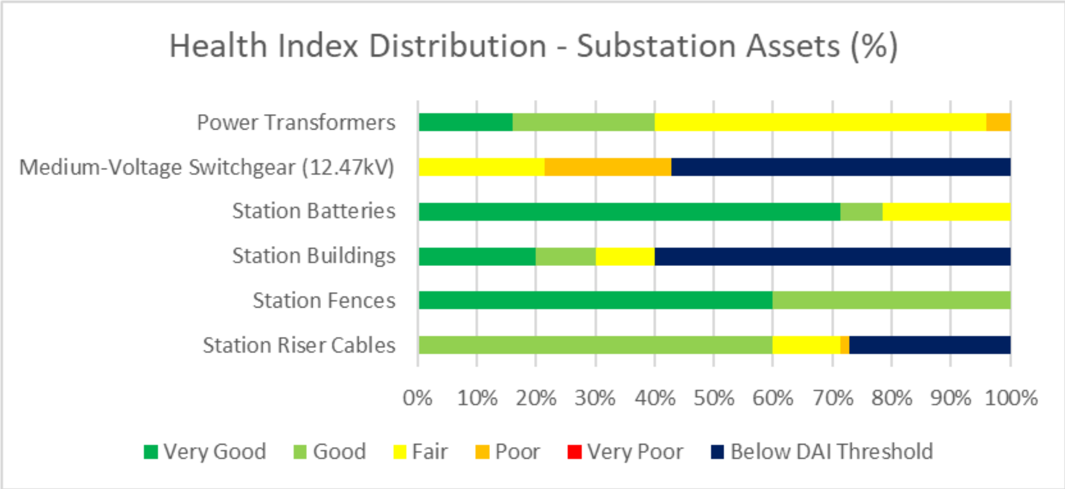
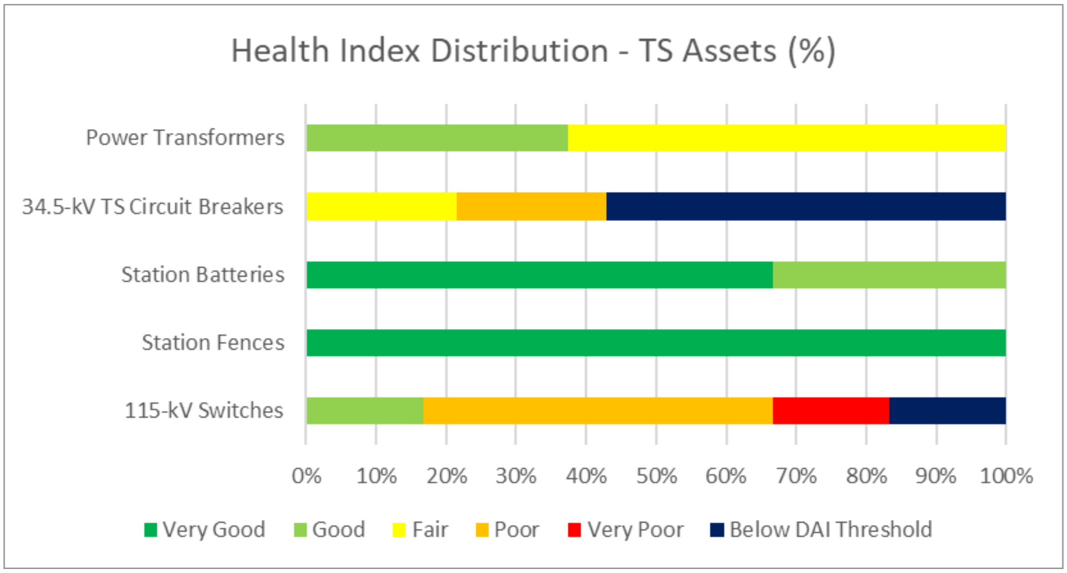


Figure 5-3: TS Asset Health Index Results



A condition-based replacement strategy could ostensibly focus on assets in Poor and Very Poor condition over the short-term. Fair condition assets should also be considered for replacement over the short-term, depending on risk/criticality. Substation and TS assets are often critical and may warrant replacement over the short-term if in Fair condition. Fair-condition assets should also be considered when developing long-term asset replacement plans.

6 Recommendations

A complete ACA framework for PUC represents an integral component of its broader AM framework, enabling it to proactively manage its distribution assets and ensure that the right actions are taken for the right assets at the right time. This framework leveraged the information captured from maintenance programs and other utility records, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging the HI insights allows for PUC's investment decision-making to be further enhanced with the current information regarding the state of the assets. There are also further opportunities to introduce new data collected, improve on data availability, and continuously improve the ACA framework.

This section breaks down METSCO's recommendations into the following categories:

1. Asset intervention strategies;
2. HI improvements; and
3. Data availability improvements.

6.1 Asset Intervention Strategies

Asset intervention options include replacement, refurbishment, or enhanced maintenance. Assets in Poor or Very Poor condition should be prioritized for intervention in the short-term. Fair-condition assets may also need to be addressed in the short-term, depending on risk. Long-term planning considerations should also consider the number of assets in Fair condition that will continue to degrade and the age profile of the assets. For example, the large number of poles installed by PUC in the 1970s and 1980s will severely pressure PUC's budget and reliability in the future if not proactively planed for.

Where feasible, asset intervention should be bundled; for example, into overhead rebuild projects, underground rebuild projects, and substation rebuild projects. While secondary bus and services were not assessed as part of this ACA, it is often economical to replace secondary bus and/or services at the same time as the primary cables/conductors in the rebuild projects. This avoids return trips to make repairs along the same feeder as secondary networks fail.

6.2 Health Index Improvements

For select asset classes, a recommended HI formulation was used for PUC's ACA framework. The following set of recommendations target additional condition parameters that can be incorporated for specific asset classes to improve the HI formulation and provide PUC with additional data to refine its asset condition calculations. The recommendations are based on improving the ACA framework over time and should not be interpreted as suggesting that immediate action is warranted. The following tables highlight the condition parameter name, a short description of the reasoning to include the condition parameter, and a priority of importance to include it into the specific asset's class HI framework. The priority is dependent on the condition parameter's weighting in comparison to the current HI framework condition parameter's weights.

1. Wood Poles

Parameters which are already covered by PUC's inspectors and contractors should be explicitly added to inspection forms so they can be included in future HI formulations.

Table 6-1: Data Collection Recommendation for Wood Poles

Criteria	Reasoning	Priority
Wood Rot	Wood rot identifies the degree of surface or internal decay and can be determined without use of special equipment.	**Medium**
Out of Plumb	Pole with excessive lean face a different load profile and are more prone to failure during extreme weather events.	**Low**

2. Underground Primary Cables

PUC has not experienced many cable failures on its system until the previous few years; however, should their rate of failure continue increase, then it would be prudent to perform more detailed analysis into cables. Recommended analyses include detailed post-mortem analysis of failed cable samples, aggregate failure/reliability analysis linked to underground cables, and cable testing to ascertain in-field condition. Cable loading is also a useful indicator of thermal degradation.

Table 6-2: Data Collection Recommendation for Underground Cable

Criteria	Reasoning	Priority
Aggregate Cable Failure Analysis	Collecting high-quality failure and reliability data for all assets – including cables – is critical for understanding the reliability of the system. PUC should establish a rigorous progress for coding failure and reliability data by the asset or event from which the failure originated.	**High**
Post-mortem Analysis	Identifying water tree samples throughout the service territory and varying age, the utility would be able to have an improved view on cable conditions within the system.	**High**
Condition of Concentric Neutral	Corrosion of concentric neutrals is another mode of degradation. Insulation degradation and cable failures can be accelerated if the cable jacket is damaged allowing moisture to enter into the insulation system. Concentric neutral corrosion is a major problem particularly on unjacketed cables or when the neutrals of the cable are exposed to excessive moisture over time. The corrosion can lead to premature cable failures and/or cause touch potential risks. Time Domain Reflectometry (TDR) tests are performed to determine the degree of corrosion on concentric neutral cables.	**Medium**
Loading History	Cable degradation can also occur due to overheating under overloading or short circuit conditions. Over stressing of insulation during voltage surges can also lead to cable failures.	**Low**

3. Pole-mount Distribution Transformers

Pole-mount transformers are inspected as part of the regular line patrol process, but these results are not logged. A detailed visual inspection of the pole-mount transformer can be done during line patrols, pole inspections, or other programs, and the results recorded for use in the ACA. IR scans can detect hot spots in the tank or connectors.

Table 6-3: Data Collection Recommendation for Overhead Distribution Transformers

Criteria	Reasoning	Priority
Visual Inspection	To identify if the transformer is subject to any physical damage, oil leak, or corrosion.	**Medium**
IR Scans	To identify hotspots on the tank, connectors, etc. during transformer operation.	**Low**

4. Pad-mount and Submersible Distribution Transformers

IR scans can also be applied to submersible and pad-mount transformers. Pad-mount transformers can be more difficult and costly to scan since the box needs to be opened, requiring a hold-off.

Table 6-4 : Data Collection Recommendation for Distribution Transformers

Criteria	Reasoning	Priority
IR Scans	To identify hotspots on the tank, connectors, etc. during transformer operation.	**Medium**

5. Underground Switches

Similar to distribution transformers, underground switches can be checked for hotspots using an IR camera.

Table 6-5: Data Collection Recommendation for Underground Switches

Criteria	Reasoning	Priority
IR Scans	To identify hotspots on the switch contacts, etc. when carrying current.	**Medium**

6. Station Power Transformers

PUC has a robust inspection and preventative maintenance program for station power transformers. The following tests are commonly applied by utilities in Ontario and can supplement PUC's present-day program to help identify adverse conditions before they develop into failures.

Table 6-6: Data Collection Recommendation for Power Transformers

Criteria	Reasoning	Priority
Turns Ratio Test	To compare the actual turns ratio vs. design rating and between phases.	**Low**
Winding Resistance	To identify degradation of the transformer winding based on the measured resistance.	**Low**

7. Station Riser Cables

Since PUC's station riser cables are aged and carry the full load of the feeder, PUC should prioritize collecting nameplate, visual inspection, and loading for these assets to form a condition assessment in the future.

Table 6-7: Data Collection Recommendation for Station Riser Cables

Criteria	Reasoning	Priority
Visual Inspection	To identify chips/cracks in the arrester, degradation of the cable terminations, or corrosion of the riser.	**High**
Loading	To identify overloaded cables that are undergoing increased thermal stresses.	**High**

6.3 Data Collection Improvements

Data availability is critical to produce prudent, accurate, and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to execute continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this ACA, the quality of the HI is dependent on the available data. For condition parameters with low data availability METSCO recommends that PUC continue collecting the information related to these data points.

Additionally, for an asset to have a valid HI, it must meet a minimum 70% of available data across the condition parameters used in the HI formulation for distribution assets and 65% for station. As part of future improvement opportunities, it is recommended that PUC continue capturing asset data for condition parameters that are currently available for a small proportion of the asset population, such that valid Health Indices can be produced across the population. It is expected that with every passing year, the inspection record database will continue to grow, allowing for Health Indices to be calculated for the remaining population.

Lastly, METSCO noticed that some condition parameters recorded by PUC vary in the detail with respect to the grading scheme. Some parameters will have a three-tier grade (e.g., Good, Fair, and Poor) and others may have five levels (e.g., from Very Good to Very Poor). METSCO recommends for PUC to evaluate options of changing some condition parameters recorded to a five-level grade, as doing so can provide more defined segregation between assets that need immediate attention and those that can still be in-service without intervention in the short term.

METSCO recommends that PUC continue to work on mitigating the existing data gaps, such that more degradation parameters can be assigned actual grades, thus expanding the sample size of valid HI, and capturing all possible degradation of the evaluated assets. PUC's testing, inspection, and maintenance programs are well-positioned to continue to capture this information using processes and technologies in place within the organization.

6.3.1 Distribution Data Collection Improvements

By bettering their data arrangement, PUC can refine their data collection. This can be exemplified in data with relation to Submersible Transformers; GIS data and inspection data are currently not coordinated, therefore was no way to connect the two sets of data. There is also a need to improve collection and validation of asset nameplate information across PUC

6.3.2 Station Data Collection Improvements

To have a better knowledge of the state of the stations' assets, it is recommended PUC incorporate more extensive visual inspection records into their monthly station reports. Some nameplate data requires verification for substation assets – in particular, station riser cables.

The current study did not assess the ground grids, communication, and P&C equipment. Communications and P&C equipment should be assessed for obsolescence, whereas the substation ground grid integrity and impedance should be verified with testing.

6.3.3 Transmission Line Condition Assessment

This ACA did not cover the transmission line poles, fittings, hardware, and insulators that PUC owns at operates at 115 kV. A separate assessment should be conducted to assess the condition of the transmission lines.

Appendix A – METSCO Company Profile

METSCO Energy Solutions Inc. is a Canadian corporation which started its operations on the market in 2006. METSCO is engaged in the business of providing consulting and project management services to electricity generating, transmission, and distribution companies, major industrial and commercial users of electricity, as well as municipalities and constructors on lighting services, asset management, and construction audits. Our head office is located in Toronto, ON and our western office is located in Calgary, AB. Through our network of associates, we provide consulting services to power sector clients around the world. A small subset of our major clients is shown in the figure below.

Figure A-0-1: METSCO Clients

METSCO has been leading the industry in Asset Condition Assessment and Asset Management practices for over ten years. Our founders are the pioneers of the first Health

Index methodology for power equipment in North America as well as the most robust risk-based analytics on the market today for high-voltage assets. METSCO has since completed hundreds of asset condition assessments, asset management plans, and asset management framework implementations. Our collective record of experience in these areas is the largest in the world, with ours being the only practice with widespread acceptance across regulatory jurisdictions. METSCO has worked with over 100 different utilities through its tenure, and as such, has been exposed and introduced to practices and unique challenges from a variety of entities, environments, and geographies. When a client chooses METSCO to work on improving Asset Management practices, it is choosing the industry-leading standard, rigorously tested and refined on a continued basis. Our experts have developed, supported, managed, led and sat on stand defending their own DSPs as utility staff giving METSCO the qualified expertise to provide its service to PUC.

In addition to our work in the area of asset health assessments and lifecycle enhancement, our services span a broad common utility issue area, including planning and asset management, design, construction supervision, project management, commissioning, troubleshooting operating problems, investigating asset failures and providing training and technology transfer.

Our founders and leaders are pioneers in their respective fields. The fundamental electrical utility-grade engineering services we provide include:

- Power sector process engineering and improvement
- Fixed Asset Investment Planning – development of economic investment plans
- Regulatory Proceeding Support
- Power System Planning and Studies – identifying system constraints
- Smart Grid Development – from planning to implementation of leading technologies
- Asset Performance and Asset Management
- Distribution and Transmission System Design
- Mentoring, Training, and Technical Resource Development
- Health Index Validation and Development
- Business Case Development
- Owners Engineering Services
- Risk Modeling – Asset Lifecycle and Risk Assessment

APPENDIX D

Overhead Expense

Board Appendix 2

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	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Bridge Year	2023 Test Year
	$ 12,999,598	$ 13,018,918	$ 12,964,547	$ 13,843,537	$ 14,597,914	$ 16,035,026
Total OM&A Before Capitalization (B)	$ 12,999,598	$ 13,018,918	$ 12,964,547	$ 13,843,537	$ 14,597,914	$ 16,035,026

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

Capitalized OM&A	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Bridge Year	2023 Test Year	Directly Attributable? (Yes/No)	Explanation for Any Change in Treatment of Capitalized Overhead
Materials	$ 279,442	$ 269,319	$ 285,879	$ 361,731	$ 315,717	$ 322,032	Yes	
Engineering	$ 400,223	$ 499,945	$ 524,173	$ 472,489	$ 904,430	$ 952,049	Yes	
Trucking	$ 426,211	$ 437,547	$ 341,102	$ 351,519	$ 437,981	$ 495,152	Yes	
Supervisory	$ 295,199	$ 341,910	$ 342,291	$ 285,571	$ 414,533	$ 319,596	Yes	
Total Capitalized OM&A (A)	$ 1,401,075	$ 1,548,723	$ 1,493,445	$ 1,471,310	$ 2,072,661	$ 2,088,829		

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

APPENDIX E

Renewable Generation Connection Investment Summary

Board Appendix 2-FA

Appendix 2-FA
Renewable Generation Connection Investment Summary (past investments or over the future rate setting period)

Enter the details of the Renewable Generation Connection projects as described in the appropriate section of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.
For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB
For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (EB-2009-0349, 6-10-2010, p. 15, note 9)
Ensure that OM&A costs below are not included in Recoverable OM&A (App. 2-JA)
There are two scenarios described below. Separate sets of spreadsheets (2-FA, 2-FB, 2-FC) should be submited for each scenario as required.

Scenario 1: Past Investments with No Recovery. The distributor has made investments in the past (during the IRM Years), but has not received approval for these projects and therefore did not receive revenue from the IESO under Regulation 330/09 and did not receive ratepayer revenue for the direct benefit portion of the investment.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's last Cost of Service approval.
The Direct Benefit portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the distributor's ratepayers through a rate rider.
The Provincial Recovery portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the IESO through a separate order.

Scenario 2: Investments in the Test Year and Beyond. Distributor plans to make investments in the Test Year and/or beyond. These investments should be added to 2-FA in the appropriate year.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's current application.

Part A

						Test Year				
REI Investments (Direct Benefit at 6%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Project 1										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Incremental OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Incremental OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Part B

						Test Year				
Expansion Investments (Direct Benefit at 17%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Project 1										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Incremental OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Incremental OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

APPENDIX F

Calculation of Renewable Generation Connection Direct Benefits: Improvements

Board Appendix 2-FB

Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables that were approved in your last cost of service test year. For test year and beyond, enter variables as in the application.
Rate Riders related to the direct benefit portion of the renewable investments are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

PUC Distribution Inc.2018			2018			2019			2020		
				Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
			Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Incremental OM&A (start-up, applicable for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**									
Allowance for Working Capital (enter rate)	7.50%			$ -	$ -		$ -	$ -		$ -	$ -
Rate Base				$ -	$ -		$ -	$ -		$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**									
Deemed ST Debt	4.00%	4.00%		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56.00%	56.00%		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40.00%	40.00%		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest (enter rate)				$ -	$ -		$ -	$ -		$ -	$ -
LT Interest (enter rate)				$ -	$ -		$ -	$ -		$ -	$ -
Return on Equity (enter rate)	9.00%			$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total				$ -	$ -		$ -	$ -		$ -	$ -
OM&A				$ -	$ -		$ -	$ -		$ -	$ -
Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs				$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement				$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection					$ -			$ -			$ -
Monthly Amount Paid by IESO					$ -			$ -			$ -

	2021			2022			Test Year 2023			2024		
		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
	Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Incremental OM&A (start-up, applicable for Provincial Recovery)	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Rebasing Year vs. Test Year												
Allowance for Working Capital (enter rate)		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rebasing Year vs. Test Year												
Deemed ST Debt		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest (enter rate)		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest (enter rate)		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Return on Equity (enter rate)		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO			$ -			$ -			$ -			$ -

Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments enter
Enter values in green shaded cells: WCA percentage, debt percentages, interest ra
For historical investments, enter these variables that were approved in your last cost of service test year. For test year and beyond, enter variables as in the application.
Rate Riders related to the direct benefit portion of the renewable investments are

PUC Distribution Inc.2018			2025			2026			2027			2028		
				Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
			Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Incremental OM&A (start-up, applicable for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**												
Allowance for Working Capital (enter rate)	7.50%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**												
Deemed ST Debt	4.00%	4.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56.00%	56.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40.00%	40.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest (enter rate)				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest (enter rate)				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Return on Equity (enter rate)	9.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection					$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO					$ -			$ -			$ -			$ -

APPENDIX G

Calculation of Renewable Generation Connection Direct Benefits: Expansion

Board Appendix 2-FC

Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables that were approved in your last cost of service test year. For test year and beyond, enter variables as in the application.
Rate Riders related to the direct benefit portion of the renewable investments are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

																			Test Year	
			2018			2019			2020			2021			2022			2023		
				Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
			Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%
Net Fixed Assets (average)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Incremental OM&A (start-up, applicable for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**																		
Allowance for Working Capital (enter rate)	7.50%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	2018	**2023**																		
Deemed ST Debt	4.00%	4.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56.00%	56.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40.00%	40.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest (enter rate)	0.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest (enter rate)	0.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Return on Equity (enter rate)	9.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection					$ -			$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO					$ -			$ -			$ -			$ -			$ -			$ -

Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables that were approved in your last cost of service test year. For test year and beyond, enter variables as in the application.
Rate Riders related to the direct benefit portion of the renewable investments are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

			2024			2025			2026			2027			2028		
				Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
			Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%
Net Fixed Assets (average)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Incremental OM&A (start-up, applicable for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**															
Allowance for Working Capital (enter rate)	7.50%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	2018	**2023**															
Deemed ST Debt	4.00%	4.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56.00%	56.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40.00%	40.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest (enter rate)	0.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest (enter rate)	0.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Return on Equity (enter rate)	9.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection					$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO					$ -			$ -			$ -			$ -			$ -