Exhibit 2:

RATE BASE

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Exhibit 2: Rate Base

Tab 1 (of 2): Rate Base

OVERVIEW

NOW Inc. has calculated a rate base for the 2025 Test Year of $11,298,138 consistent with Chapter 2 of the *Filing Requirements for Electricity Transmission and Distribution Applications* issued on December 15, 2022. The rate base calculation is based on the average of the 2025 Test Year opening and closing balances of the net book value of assets, plus a working capital allowance. The working capital allowance is calculated as 7.5% of the sum of controllable expenses and the cost of power. Controllable expenses include operations and maintenance, billing and collecting, and administrative expenses.

A rate base continuity schedule from the 2017 OEB Approved amount to the 2025 Test Year is provided below in **Table 1**. The 2024 Bridge Year and 2025 Test Year are budgeted costs as per the application.

Table 1
Rate Base Continuity Schedule

Description	2017 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Opening Balance Gross Fixed Assets	8,049,328	8,027,245	8,737,001	9,566,534	10,254,916	10,874,235	11,386,651	11,974,944	12,311,683	15,195,967
Closing Balance Gross Fixed Assets	8,826,828	8,737,001	9,566,534	10,254,916	10,874,235	11,386,651	11,974,944	12,311,683	15,195,967	17,022,892
Average Gross Fixed Assets	8,438,078	8,382,123	9,151,768	9,910,725	10,564,575	11,130,443	11,680,798	12,143,314	13,753,825	16,109,429
Opening Balance Accumulated Depreciation	- 1,823,463	- 1,805,457	- 2,342,144	- 2,950,496	- 3,483,425	- 4,010,049	- 4,498,981	- 4,919,306	- 5,388,533	- 5,890,532
Closing Balance Accumulated Depreciation	- 2,471,862	- 2,342,144	- 2,950,496	- 3,483,425	- 4,010,049	- 4,498,981	- 4,919,306	- 5,388,533	- 5,890,532	- 6,448,906
Average Accumulated Depreciation	- 2,147,662	- 2,073,800	- 2,646,320	- 3,216,960	- 3,746,737	- 4,254,515	- 4,709,143	- 5,153,920	- 5,639,533	- 6,169,719
Opening Net Book Value	6,225,865	6,221,788	6,394,858	6,616,039	6,771,491	6,864,186	6,887,671	7,055,638	6,923,150	9,305,435
Closing Net Book Value	6,354,966	6,394,858	6,616,039	6,771,491	6,864,186	6,887,671	7,055,638	6,923,150	9,305,435	10,573,985
Average Net Book Value	6,290,416	6,308,323	6,505,448	6,693,765	6,817,838	6,875,928	6,971,654	6,989,394	8,114,292	9,939,710
Working Capital	19,695,996	17,539,049	16,376,772	17,283,556	18,159,448	16,315,946	16,664,876	16,636,475	17,335,775	18,112,365
Working Capital %	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	1,477,200	1,315,429	1,228,258	1,296,267	1,361,959	1,223,696	1,249,866	1,247,736	1,300,183	1,358,427
Rate Base	7,767,615	7,623,751	7,733,706	7,990,032	8,179,797	8,099,624	8,221,520	8,237,130	9,414,475	11,298,138

NOW Inc. does not have any non-distribution assets and opening and closing gross fixed asset and depreciation balances have been submitted into evidence in the fixed asset continuity schedules (OEB Chapter 2 Appendix 2-BA) which are provided in E2/T1/S1/Att1.

A summary of the cost components used to calculate the Working Capital Allowance is provided below in **Table 2**. As shown in the table, Cost of Power is a significant factor in the total working capital. This is not controllable by NOW Inc. and NOW Inc. must pay the IESO invoices regardless of if customers default on their payments.

Table 2

Working Capital Summary

Description	2017 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Cost of Power	16,938,090	14,849,059	13,686,932	14,509,423	15,398,378	13,568,550	13,754,113	13,397,602	13,531,578	13,561,454
Operations	817,472	734,009	938,481	927,458	852,226	930,035	919,278	1,025,060	999,605	1,207,276
Maintenance	565,783	495,810	440,705	488,484	639,441	536,320	702,981	743,962	980,909	1,370,467
Billing & Collecting	726,564	775,872	749,498	757,348	688,585	680,520	642,584	703,383	776,167	937,555
Administrative and General	648,087	684,299	561,156	600,844	580,818	600,521	645,920	766,468	1,047,516	1,035,613
Working Capital	19,695,996	17,539,049	16,376,772	17,283,556	18,159,448	16,315,946	16,664,876	16,636,475	17,335,775	18,112,365

Major Drivers of Change in Rate Base

From the 2017 OEB approved to the 2025 Test Year, the average net book value (NBV) of property, plant and equipment has increased by $3,649,294. Over the same period working capital allowance has decreased $118,772.

The main driver of the change in rate base is as follows:

- The ongoing capital expenditures and additions for distribution system investments as outlined in E2/T2/S1, partially offset by ongoing depreciation of capital assets, and
- This is partially offset by a decrease in the working capital allowance as a result of the Ontario Energy Rebate which reduces Cost of Power.

The primary driver of the increase in rate base is the increase in the net book value of assets. The net book values for 2017 to 2025 are summarized in Table 3 and the associated year over year variances follow in Table 4. Year over year changes greater than the NOW Inc. materiality level of $50,000 are highlighted and explained below:

Table 3

2017 – 2025 Net Book Value

OEB Account	Description	2017 Approved Net Book Value	2017 Net Book Value	2018 Net Book Value	2019 Net Book Value	2020 Net Book Value	2021 Net Book Value	2022 Net Book Value	2023 Net Book Value	2024 Net Book Value	2025 Net Book Value
1611	Computer Software (Formally known as Account 1925)	$366,175	$385,023	$334,739	$264,612	$194,484	$124,357	$54,230	$64,373	$874,483	$756,242
1805	Land	$87,700	$87,700	$87,700	$87,700	$87,700	$87,700	$87,700	$87,700	$172,700	$172,700
1808	Buildings	$383,511	$383,512	$364,139	$344,766	$325,393	$306,020	$307,729	$291,474	$270,878	$279,531
1820	Distribution Station Equipment <50 kV	$243,173	$235,420	$313,459	$314,857	$303,352	$302,368	$290,622	$278,874	$750,622	$733,982
1830	Poles, Towers & Fixtures	$2,062,838	$1,998,092	$2,134,807	$2,284,968	$2,384,022	$2,505,275	$2,608,962	$2,567,110	$2,737,643	$3,531,325
1835	Overhead Conductors & Devices	$1,249,624	$1,383,698	$1,560,544	$1,703,743	$1,794,692	$1,894,693	$1,962,741	$1,945,666	$2,029,558	$2,536,160
1840	Underground Conduit	$4,092	$4,092	$2,728	$2,490	$182,780	$178,625	$174,470	$170,316	$166,161	$162,006
1845	Underground Conductors & Devices	$906	$5,232	$4,832	$6,916	$6,459	$6,304	$6,150	$5,995	$76,249	$74,494
1850	Line Transformers	$645,220	$598,219	$672,329	$746,316	$735,571	$793,653	$827,292	$816,677	$1,133,164	$1,373,557
1855	Services (Overhead & Underground)	$192,299	$246,474	$253,708	$264,727	$258,365	$258,845	$241,973	$225,101	$280,421	$272,213
1860	Meters	$12,936	$12,936	$11,210	$11,821	$26,503	$24,680	$23,149	$37,008	$34,848	$32,688
1860	Meters (Smart Meters)	$444,477	$431,687	$383,491	$322,038	$274,574	$254,651	$195,134	$148,075	$100,906	$91,642
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$1,599	$6,925	$5,787	$4,650	$3,513	$2,436	$25,041	$20,449	$16,396	$12,753
1920	Computer Equipment - Hardware	$21,015	$12,015	$7,868	$6,668	$3,089	$1,082	$6,808	$0	$0	$0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$213,748	$213,749	$180,864	$147,980	$115,095	$82,211	$49,326	$29,095	$31,868	$28,301
1930	Transportation Equipment	$512,089	$508,704	$421,288	$382,663	$295,232	$192,192	$318,447	$352,668	$663,068	$547,979
1935	Stores Equipment	$70	$68	$0	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	$29,796	$16,126	$10,565	$7,805	$5,795	$4,219	$5,325	$8,464	$6,911	$13,908
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$81,890	$73,270
1955	Communications Equipment	$0	$12,478	$9,705	$6,932	$4,159	$1,386	($0)	($0)	($0)	($0)
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
2440	Deferred Revenue	($116,303)	($147,292)	($143,726)	($140,160)	($136,594)	($133,028)	($129,462)	($125,897)	($122,331)	($118,765)
		$6,354,966	**$6,394,858**	**$6,616,039**	**$6,771,491**	**$6,864,186**	**$6,887,671**	**$7,055,638**	**$6,923,150**	**$9,305,435**	**$10,573,985**

Table 4

2017 – 2025 Net Book Value Variances

OEB Account	Description	2017 Actual vs 2017 OEB Approved NBV Variance	2018 Actual vs 2017 Actual NBV Variance	2019 Actual vs 2018 Actual NBV Variance	2020 Actual vs 2019 Actual NBV Variance	2021 Actual vs 2020 Actual NBV Variance	2022 Actual vs 2021 Actual NBV Variance	2023 Actual vs 2022 Actual NBV Variance	2024 Bridge vs 2023 Actual NBV Variance	2025 Test vs 2024 Bridge NBV Variance
1611	Computer Software (Formally known as Account 1925)	$18,848	($50,284)	($70,127)	($70,127)	($70,127)	($70,127)	$10,143	$810,110	($118,241)
1805	Land	$0	$0	$0	$0	$0	$0	$0	$85,000	$0
1808	Buildings	$1	($19,373)	($19,373)	($19,373)	($19,373)	$1,709	($16,255)	($20,597)	$8,654
1820	Distribution Station Equipment <50 kV	($7,753)	$78,039	$1,398	($11,505)	($984)	($11,746)	($11,748)	$471,748	($16,640)
1830	Poles, Towers & Fixtures	($64,746)	$136,715	$150,161	$99,055	$121,252	$103,687	($41,852)	$170,532	$793,682
1835	Overhead Conductors & Devices	$134,074	$176,846	$143,199	$90,949	$100,001	$68,048	($17,075)	$83,892	$506,602
1840	Underground Conduit	($0)	($1,364)	($238)	$180,289	($4,155)	($4,155)	($4,155)	($4,155)	($4,155)
1845	Underground Conductors & Devices	$4,326	($400)	$2,084	($456)	($155)	($155)	($155)	$70,254	($1,755)
1850	Line Transformers	($47,001)	$74,111	$73,986	($10,745)	$58,083	$33,638	($10,615)	$316,487	$240,393
1855	Services (Overhead & Underground)	$54,175	$7,235	$11,018	($6,361)	$479	($16,872)	($16,872)	$55,319	($8,208)
1860	Meters	$0	($1,726)	$611	$14,682	($1,823)	($1,532)	$13,859	($2,160)	($2,160)
1860	Meters (Smart Meters)	($12,790)	($48,196)	($61,453)	($47,464)	($19,924)	($59,516)	($47,060)	($47,169)	($9,264)
1910	Leasehold Improvements	$0	$0	$0	$0	$0	$0	$0	$0	$0
1915	Office Furniture & Equipment (10 years)	$5,326	($1,137)	($1,137)	($1,136)	($1,078)	$22,606	($4,592)	($4,053)	($3,644)
1920	Computer Equipment - Hardware	($9,000)	($4,147)	($1,199)	($3,580)	($2,006)	$5,726	($6,808)	$0	$0
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$0	$0	$0	$0	$0	$0	$0	$0	$0
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$1	($32,885)	($32,885)	($32,885)	($32,885)	($32,885)	($20,231)	$2,773	($3,568)
1930	Transportation Equipment	($3,386)	($87,416)	($38,624)	($87,432)	($103,040)	$126,255	$34,221	$310,400	($115,089)
1935	Stores Equipment	($2)	($68)	$0	$0	$0	$0	$0	$0	$0
1940	Tools, Shop & Garage Equipment	($13,670)	($5,561)	($2,760)	($2,010)	($1,576)	$1,105	$3,139	($1,553)	$6,997
1950	Power Operated Equipment	$0	$0	$0	$0	$0	$0	$0	$81,890	($8,620)
1955	Communications Equipment	$12,478	($2,773)	($2,773)	($2,773)	($2,773)	($1,386)	$0	$0	$0
1960	Miscellaneous Equipment	$0	$0	$0	$0	$0	$0	$0	$0	$0
2440	Deferred Revenue	($30,989)	$3,566	$3,566	$3,566	$3,566	$3,566	$3,566	$3,566	$3,566
		$39,891	$221,181	$155,453	$92,695	$23,485	$167,968	($132,489)	$2,382,285	$1,268,550

EXPLANATION OF MATERIAL YEAR OVER YEAR VARIANCES

Table 5

2017 Actual to 2017 OEB Approved

Account Grouping	Variance ($)
Poles, Towers & Fixtures	($64,746)
Overhead Conductors & Devices	$134,074
Services (Overhead & Underground)	$54,175

- Poles, Towers & Fixtures, $64,746 less than approved because of decrease in capital work on poles.
- Overhead Conductors and Devices, $134,074 higher mainly due to additional work from line patrols.
- Services (Overhead & Underground) $54,175 higher due to increases in secondary service ground fault repairs.

Table 6

2018 Actual to 2017 Actual

Account Grouping	Variance ($)
Computer Software	($50,284)
Distribution Station Equipment <50 kV	$78,039
Poles, Towers & Fixtures	$136,715
Overhead Conductors & Devices	$176,846
Line Transformers	$74,111
Transportation Equipment	($87,416)

- Computer Software, $50,284 lower primarily due to more amortization of software.
- Distribution Station Equipment, 2018 Net Book Value is $78,039 higher than 2017 NBV due to increase in substation work in 2018.

- Poles, Towers and Fixtures, Net Book Value in 2018 is $136,715 higher than 2017 primarily due to more capital pole replacements.
- Overhead Conductors and Devices, NBV in 2018 is $176,846 higher than 2017 primarily due to more capital work required that was identified from line patrols.
- Line Transformers, 2018 NBV is $74,111 higher than 2017 primarily due to the replacement of additional transformers as a part of the conversion projects.
- Transportation Equipment, 2018 NBV is $87,416 lower than 2017 because of depreciation

Table 7

2019 Actual to 2018 Actual

Account Grouping	Variance ($)
Computer Software	($70,127)
Poles, Towers & Fixtures	$150,161
Overhead Conductors & Devices	$143,199
Line Transformers	$73,986
Meters (Smart Meters)	($61,453)

- Computer Software, $70,127 lower due to more amortization of software.
- Poles, Towers and Fixtures, Net Book Value in 2019 is $150,161 higher than 2018 primarily due to more capital pole replacements
- Overhead Conductors and Devices, NBV in 2019 is $143,199 higher than 2018 primarily due to more capital work required that was identified from line patrols
- Line Transformers, 2019 NBV is $73,986 higher than 2018 primarily due to the replacement of additional transformers as a part of the conversion projects.
- Meters (Smart Meters), the 2019 Net Book Value is $61,453 lower than 2018 NBV due to the amortization of smart meters.

Table 8

2020 Actual to 2019 Actual

Account Grouping	Variance ($)
Computer Software	($70,127)
Poles, Towers & Fixtures	$99,055
Overhead Conductors & Devices	$90,949
Underground Conduit	$180,289
Transportation Equipment	($87,432)

- Computer Software, $70,127 Lower due to more amortization of software.
- Poles, Towers and Fixtures, Net Book Value in 2020 is $99,055 higher than 2019 primarily due to more capital pole replacements
- Overhead Conductors and Devices, NBV in 2020 is $90,949 higher than 2019 primarily due to more capital work required that was identified from line patrols
- Underground Conduit, NBV in 2020 is $180,289 higher than 2019 primarily due to more capital work required for the Cochrane station and Mateev subdivision.
- Transportation Equipment, 2020 NBV is $87,432 lower than 2019 because of depreciation outpacing additions.

Table 9

2021 Actual to 2020 Actual

Account Grouping	Variance ($)
Computer Software	($70,127)
Poles, Towers & Fixtures	$121,252
Overhead Conductors & Devices	$100,001
Line Transformers	$58,083
Transportation Equipment	($103,040)

- Computer Software, $70,127 lower due to more amortization of software.

- Poles, Towers and Fixtures, Net Book Value in 2021 is $121,252 higher than 2020 primarily due to more capital pole replacements
- Overhead Conductors and Devices, NBV in 2021 is $100,001 higher than 2020 primarily due to more capital work required that was identified from line patrols
- Line Transformers, 2021 NBV is anticipated to be $58,083 higher than 2020 primarily due to the replacement of additional transformers as a part of the conversion projects.
- Transportation Equipment, 2021 NBV is $103,040 lower than 2020 because of depreciation and no additions.

Table 10

2022 Actual to 2021 Actual

Account Grouping	Variance ($)
Computer Software	($70,127)
Poles, Towers & Fixtures	$103,687
Overhead Conductors & Devices	$68,048
Meters (Smart Meters)	($59,516)
Transportation Equipment	$126,255

- Computer Software, $70,127 lower primarily due to more amortization of software.
- Poles, Towers and Fixtures, Net Book Value in 2022 is $103,687 higher than 2021 primarily due to more capital pole replacements
- Overhead Conductors and Devices, NBV in 2022 is $68,048 higher than 2021 primarily due to more capital work required that was identified from line patrols
- Meters (Smart Meters), the 2022 Net Book Value is $59,516 lower than 2021 NBV due to the amortization of smart meters.
- Transportation Equipment, 2022 NBV is $126,255 higher than 2021 because of an increase in repair cost and fleet additions with small trucks.

2023 Actual to 2022 Actual

No variances have reached the material threshold over 50K for this fiscal year.

2024 Bridge Year to 2023 Actual

Table 11

2024 Bridge Year to 2023 Actual

Account Grouping	Variance ($)
Computer Software	$810,110
Land	$85,000
Distribution Station Equipment <50 kV	$471,748
Poles, Towers & Fixtures	$170,532
Overhead Conductors & Devices	$83,892
Underground Conductors & Devices	$70,254
Line Transformers	$316,487
Services (Overhead & Underground)	$55,319
Transportation Equipment	$310,400
Power Operated Equipment	$81,890

- Computer Software, NBV in 2024 is $810,110 higher than 2023 primarily due to Go360 project, system data gathering and implementation for asset management system and data gathering for transformer PCB testing.
- Land, NBV in 2024 is $85,000 higher than 2023 due to land purchase from the town of Cochrane for New MTS project.
- Distribution Station Equipment, NBV in 2024 is $471,748 higher than 2023 due to the inclusion major spare parts such as reclosures, gang operated switches and distribution transformers.

- Poles, Towers and Fixtures, NBV in 2024 is $170,532 higher than 2023 primarily due to identified areas of concern because of line patrols that will result in more anticipated pole replacements.
- Overhead Conductors and Devices, NBV in 2024 is $83,892 higher than 2023 primarily due to more capital work required that was identified from line patrols
- Underground Conductor & Devices, NBV in 2024 is $70,254 higher than 2023 primarily due to capital work required in subdivisions.
- Line Transformers, NBV in 2024 is $316,487 higher than 2023 due to the inclusion of major spare parts as a minimal requirement for emergency replacements for differing variations in voltages of our three distribution systems.
- Services (Overhead & Underground), NBV in 2024 is $55,319 higher than 2023 due to added capital work required on services due to conversion projects.
- Transportation Equipment, 2024 NBV is $310,400 higher than 2023 because of fleet additions with new Altec Bucket Truck.
- Power Operated Equipment, 2024 NBV is $81,890 higher than 2023 because of equipment additions with new Ditch Witch hydro vac trailer and trencher.

Table 12

2025 Test Year to 2024 Bridge Year

Account Grouping	Variance ($)
Computer Software	($118,241)
Poles, Towers & Fixtures	$793,682
Overhead Conductors & Devices	$506,602
Line Transformers	$240,393
Transportation Equipment	($115,089)

- Computer Software, NBV in 2025 is $118,241 lower than 2024 due to Go360 project, system data gathering and implementation for asset management system and data gathering for transformer PCB testing reduction of spending and amortization.

- Poles, Towers & Fixtures, NBV in 2025 is $793,682 higher than 2024 primarily due to additional work as a resulting from the increased scope of voltage conversion project upgrades.
- Overhead Conductors and Devices, NBV in 2025 is $506,602 higher than 2024 primarily due to additional work as a resulting from the increased scope of voltage conversion project upgrades.
- Line Transformers, NBV in 2025 is $240,393 higher than 2024 primarily due to additional work as a resulting from the increased scope of voltage conversion project upgrades.
- Transportation Equipment, NBV in 2025 is $115,089 lower than 2024 as a result of depreciation.

Attachment 1 (of 1):

OEB Appendix 2-BA

Appendix 2-BA
Fixed Asset Continuity Schedule [1]

Notes:

1 Tables in the format outlined above covering all fixed asset accounts should be submitted for the Test Year, Bridge Year and all relevant historical years. At a minimum , the applicant must provide data for the earlier of: 1) all historical years back to its last rebasing; or 2) at least three years of historical actuals, in addition to Bridge Year and Test Year forecasts. If this is the first application where the applicant is rebasing under MIFRS, contact OEB staff for further guidance on the appropriate fixed asset continuity schedules to complete (i.e. applicable years and accounting standard for each schedule).

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

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

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

5 Effective on the date of IFRS adoption, customer contributions will no longer be recorded in Account 1995 Contributions & Grants, but will be recorded in Account 2440, Deferred Revenues. Amortization of deferred revenue will be removed from the depreciation expense shown on this fixed asset continuity schedule as it should be included as income in Appendix 2-H Other Revenues.

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

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

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

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Accounting Standard MIFRS
Year **2017**

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
	1609	Capital Contributions Paid				$ -				$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 427,908	$ 97,120	-$ 48,167	$ 476,861	-$ 79,461	-$ 60,544	$ 48,167	-$ 91,838	$ 385,023
CEC	1612	Land Rights (Formally known as Account 1906)				$ -				$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700				$ -	$ 87,700
47	1808	Buildings	$ 462,385			$ 462,385	-$ 59,500	-$ 19,373		-$ 78,873	$ 383,512
13	1810	Leasehold Improvements				$ -				$ -	$ -
47	1815	Transformer Station Equipment >50 kV				$ -				$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 274,445	$ 43,548		$ 317,993	-$ 60,301	-$ 22,272		-$ 82,573	$ 235,420
47	1825	Storage Battery Equipment				$ -				$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,231,239	$ 283,268	-$ 6,913	$ 2,507,594	-$ 377,356	-$ 136,140	$ 3,994	-$ 509,503	$ 1,998,092
47	1835	Overhead Conductors & Devices	$ 1,291,475	$ 241,402	-$ 1,953	$ 1,530,924	-$ 106,106	-$ 42,478	$ 1,358	-$ 147,225	$ 1,383,698
47	1840	Underground Conduit	$ 9,548			$ 9,548	-$ 4,092	-$ 1,364		-$ 5,456	$ 4,092
47	1845	Underground Conductors & Devices	$ 2,110	$ 4,376		$ 6,486	-$ 904	-$ 350		-$ 1,255	$ 5,232
47	1850	Line Transformers	$ 621,414	$ 61,221	-$ 1,907	$ 680,729	-$ 59,203	-$ 23,681	$ 374	-$ 82,510	$ 598,219
47	1855	Services (Overhead & Underground)	$ 238,324	$ 55,543		$ 293,867	-$ 33,382	-$ 14,011		-$ 47,393	$ 246,474
47	1860	Meters	$ 21,583			$ 21,583	-$ 6,684	-$ 1,964		-$ 8,647	$ 12,936
47	1860	Meters (Smart Meters)	$ 675,238	$ 1,770		$ 677,007	-$ 184,781	-$ 60,539		-$ 245,320	$ 431,687
N/A	1905	Land				$ -				$ -	$ -
47	1908	Buildings & Fixtures				$ -				$ -	$ -
13	1910	Leasehold Improvements	$ 469			$ 469	-$ 469			-$ 469	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 2,489	$ 5,736		$ 8,225	-$ 573	-$ 728		-$ 1,300	$ 6,925
8	1915	Office Furniture & Equipment (5 years)				$ -				$ -	$ -
10	1920	Computer Equipment - Hardware	$ 25,760			$ 25,760	-$ 8,298	-$ 5,447		-$ 13,745	$ 12,015
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)				$ -				$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364			$ 348,364	-$ 101,730	-$ 32,885		-$ 134,615	$ 213,749
10	1930	Transportation Equipment	$ 1,362,830		-$ 33,141	$ 1,329,689	-$ 660,592	-$ 190,149	$ 29,756	-$ 820,985	$ 508,704
8	1935	Stores Equipment	$ 876			$ 876	-$ 740	-$ 68		-$ 808	$ 68
8	1940	Tools, Shop & Garage Equipment	$ 88,863	$ 2,311		$ 91,173	-$ 64,618	-$ 10,430		-$ 75,047	$ 16,126
8	1945	Measurement & Testing Equipment				$ -				$ -	$ -
8	1950	Power Operated Equipment				$ -				$ -	$ -
8	1955	Communications Equipment	$ 1,186	$ 13,865		$ 15,050	-$ 1,186	-$ 1,386		-$ 2,572	$ 12,478
8	1955	Communication Equipment (Smart Meters)				$ -				$ -	$ -
8	1960	Miscellaneous Equipment				$ -				$ -	$ -
47	1970	Load Management Controls Customer Premises				$ -				$ -	$ -
47	1975	Load Management Controls Utility Premises				$ -				$ -	$ -
47	1980	System Supervisor Equipment				$ -				$ -	$ -
47	1985	Miscellaneous Fixed Assets				$ -				$ -	$ -
47	1990	Other Tangible Property				$ -				$ -	$ -
47	1995	Contributions & Grants				$ -				$ -	$ -
47	2440	Deferred Revenue[5]	-$ 146,961	-$ 8,321		-$ 155,283	$ 4,520	$ 3,471		$ 7,991	-$ 147,292
	2005	Property Under Finance Lease[7]				$ -				$ -	$ -
		Sub-Total	**$ 8,027,245**	**$ 801,837**	**-$ 92,081**	**$ 8,737,001**	**-$ 1,805,457**	**-$ 620,336**	**$ 83,650**	**-$ 2,342,144**	**$ 6,394,858**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 8,027,245**	**$ 801,837**	**-$ 92,081**	**$ 8,737,001**	**-$ 1,805,457**	**-$ 620,336**	**$ 83,650**	**-$ 2,342,144**	**$ 6,394,858**
		Construction Work In Progress	$ 212,240	$ 34,416		$ 246,657				$ -	$ 246,657
		Total PP&E	**$ 8,239,485**	**$ 836,253**	**-$ 92,081**	**$ 8,983,658**	**-$ 1,805,457**	**-$ 620,336**	**$ 83,650**	**-$ 2,342,144**	**$ 6,641,514**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-19882.87			
		Total						**-$ 640,219**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 190,149
8		Stores Equipment	Stores Equipment	-$ 19,373
47		Deferred Revenue	Deferred Revenue	$ 3,471
			Net Depreciation	**-$ 434,168**

Accounting Standard MIFRS
Year **2018**

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
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 476,861	$ 18,521		$ 495,381	-$ 91,838	-$ 68,804		-$ 160,642	$ 334,739
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700	$ -			$ -	$ 87,700
47	1808	Buildings	$ 462,385			$ 462,385	-$ 78,873	-$ 19,373		-$ 98,246	$ 364,139
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 317,993	$ 87,882		$ 405,875	-$ 82,573	-$ 9,843		-$ 92,416	$ 313,459
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,507,594	$ 281,138	-$ 4,932	$ 2,783,800	-$ 509,503	-$ 142,463	$ 2,972	-$ 648,994	$ 2,134,807
47	1835	Overhead Conductors & Devices	$ 1,530,924	$ 230,992	-$ 8,495	$ 1,753,421	-$ 147,225	-$ 47,681	$ 2,030	-$ 192,876	$ 1,560,544
47	1840	Underground Conduit	$ 9,548			$ 9,548	-$ 5,456	-$ 1,364		-$ 6,820	$ 2,728
47	1845	Underground Conductors & Devices	$ 6,486			$ 6,486	-$ 1,255	-$ 400		-$ 1,654	$ 4,832
47	1850	Line Transformers	$ 680,729	$ 101,231	-$ 1,980	$ 779,980	-$ 82,510	-$ 25,581	$ 440	-$ 107,650	$ 672,329
47	1855	Services (Overhead & Underground)	$ 293,867	$ 26,855		$ 320,722	-$ 47,393	-$ 19,620		-$ 67,013	$ 253,708
47	1860	Meters	$ 21,583			$ 21,583	-$ 8,647	-$ 1,726		-$ 10,373	$ 11,210
47	1860	Meters (Smart Meters)	$ 677,007	$ 12,829		$ 689,836	-$ 245,320	-$ 61,025		-$ 306,345	$ 383,491
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 469			$ 469	-$ 469			-$ 469	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 8,225			$ 8,225	-$ 1,300	-$ 1,137		-$ 2,438	$ 5,787
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 25,760			$ 25,760	-$ 13,745	-$ 4,147		-$ 17,893	$ 7,868
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364			$ 348,364	-$ 134,615	-$ 32,885		-$ 167,499	$ 180,864
10	1930	Transportation Equipment	$ 1,329,689	$ 85,492		$ 1,415,181	-$ 820,985	-$ 172,908		-$ 993,894	$ 421,288
8	1935	Stores Equipment	$ 876			$ 876	-$ 808	-$ 68		-$ 876	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 91,173			$ 91,173	-$ 75,047	-$ 5,561		-$ 80,608	$ 10,565
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 15,050			$ 15,050	-$ 2,572	-$ 2,773		-$ 5,345	$ 9,705
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 155,283			-$ 155,283	$ 7,991	$ 3,566		$ 11,557	-$ 143,726
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 8,737,001**	**$ 844,940**	**-$ 15,407**	**$ 9,566,534**	**-$ 2,342,144**	**-$ 613,794**	**$ 5,442**	**-$ 2,950,496**	**$ 6,616,039**
		Less Socialized Renewable Energy Generation Investments (input as negative)	$ -			$ -	$ -			$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)	$ -			$ -	$ -			$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 8,737,001**	**$ 844,940**	**-$ 15,407**	**$ 9,566,534**	**-$ 2,342,144**	**-$ 613,794**	**$ 5,442**	**-$ 2,950,496**	**$ 6,616,039**
		Construction Work In Progress	$ 246,657	$ 35,985		$ 282,641				$ -	$ 282,641
		Total PP&E	**$ 8,983,658**	**$ 880,925**	**-$ 15,407**	**$ 9,849,176**	**-$ 2,342,144**	**-$ 613,794**	**$ 5,442**	**-$ 2,950,496**	**$ 6,898,680**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-20849.08			
		Total						**-$ 634,643**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 172,908
8		Stores Equipment	Stores Equipment	-$ 19,373
47		Deferred Revenue	Deferred Revenue	$ 3,566
			Net Depreciation	**-$ 445,928**

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Accounting Standard MIFRS
Year **2019**

			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**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 495,381			$ 495,381	-$ 160,642	-$ 70,127		-$ 230,770	$ 264,612
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700	$ -			$ -	$ 87,700
47	1808	Buildings	$ 462,385			$ 462,385	-$ 98,246	-$ 19,373		-$ 117,619	$ 344,766
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 405,875	$ 12,661		$ 418,536	-$ 92,416	-$ 11,263		-$ 103,679	$ 314,857
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 2,783,800	$ 230,001	-$ 12,933	$ 3,000,868	-$ 648,994	-$ 76,505	$ 9,598	-$ 715,901	$ 2,284,968
47	1835	Overhead Conductors & Devices	$ 1,753,421	$ 205,421	-$ 14,390	$ 1,944,452	-$ 192,876	-$ 51,860	$ 4,028	-$ 240,709	$ 1,703,743
47	1840	Underground Conduit	$ 9,548	$ 1,139		$ 10,687	-$ 6,820	-$ 1,377		-$ 8,197	$ 2,490
47	1845	Underground Conductors & Devices	$ 6,486	$ 2,511		$ 8,998	-$ 1,654	-$ 428		-$ 2,082	$ 6,916
47	1850	Line Transformers	$ 779,980	$ 106,175	-$ 6,605	$ 879,549	-$ 107,650	-$ 27,412	$ 1,829	-$ 133,234	$ 746,316
47	1855	Services (Overhead & Underground)	$ 320,722	$ 27,006		$ 347,728	-$ 67,013	-$ 15,988		-$ 83,001	$ 264,727
47	1860	Meters	$ 21,583	$ 1,796		$ 23,379	-$ 10,373	-$ 1,185		-$ 11,558	$ 11,821
47	1860	Meters (Smart Meters)	$ 689,836			$ 689,836	-$ 306,345	-$ 61,453		-$ 367,798	$ 322,038
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 469			$ 469	-$ 469			-$ 469	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 8,225			$ 8,225	-$ 2,438	-$ 1,137		-$ 3,575	$ 4,650
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 25,760	$ 2,164	-$ 2,000	$ 25,924	-$ 17,893	-$ 3,363	$ 2,000	-$ 19,256	$ 6,668
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364			$ 348,364	-$ 167,499	-$ 32,885		-$ 200,384	$ 147,980
10	1930	Transportation Equipment	$ 1,415,181	$ 135,435		$ 1,550,616	-$ 993,894	-$ 174,059		-$ 1,167,953	$ 382,663
8	1935	Stores Equipment	$ 876			$ 876	-$ 876			-$ 876	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 91,173			$ 91,173	-$ 80,608	-$ 2,760		-$ 83,369	$ 7,805
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 15,050			$ 15,050	-$ 5,345	-$ 2,773		-$ 8,118	$ 6,932
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 155,283			-$ 155,283	$ 11,557	$ 3,566		$ 15,123	-$ 140,160
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 9,566,534**	**$ 724,309**	**-$ 35,928**	**$ 10,254,916**	**-$ 2,950,496**	**-$ 550,383**	**$ 17,454**	**-$ 3,483,425**	**$ 6,771,491**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 9,566,534**	**$ 724,309**	**-$ 35,928**	**$ 10,254,916**	**-$ 2,950,496**	**-$ 550,383**	**$ 17,454**	**-$ 3,483,425**	**$ 6,771,491**
		Construction Work In Progress	$ 282,641	$ 10,598	-$ 60,708	$ 232,532				$ -	$ 232,532
		Total PP&E	**$ 9,849,176**	**$ 734,908**	**-$ 96,636**	**$ 10,487,447**	**-$ 2,950,496**	**-$ 550,383**	**$ 17,454**	**-$ 3,483,425**	**$ 7,004,023**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-18473.46			
		Total						**-$ 568,857**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	-$ 174,059
8		Stores Equipment	Stores Equipment	-$ 19,373
47		Deferred Revenue	Deferred Revenue	$ 3,566
			Net Depreciation	**-$ 378,991**

Accounting Standard MIFRS
Year 2020

			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**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 495,381			$ 495,381	-$ 230,770	-$ 70,127		-$ 300,897	$ 194,484
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700	$ -			$ -	$ 87,700
47	1808	Buildings	$ 462,385			$ 462,385	-$ 117,619	-$ 19,373		-$ 136,992	$ 325,393
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 418,536			$ 418,536	-$ 103,679	-$ 11,505		-$ 115,184	$ 303,352
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,000,868	$ 178,885	-$ 5,955	$ 3,173,798	-$ 715,901	-$ 77,040	$ 3,165	-$ 789,776	$ 2,384,022
47	1835	Overhead Conductors & Devices	$ 1,944,452	$ 148,609	-$ 4,036	$ 2,089,024	-$ 240,709	-$ 55,166	$ 1,542	-$ 294,333	$ 1,794,692
47	1840	Underground Conduit	$ 10,687	$ 183,720		$ 194,407	-$ 8,197	-$ 3,431		-$ 11,627	$ 182,780
47	1845	Underground Conductors & Devices	$ 8,998			$ 8,998	-$ 2,082	-$ 456		-$ 2,538	$ 6,459
47	1850	Line Transformers	$ 879,549	$ 18,609	-$ 1,297	$ 896,861	-$ 133,234	-$ 28,488	$ 432	-$ 161,290	$ 735,571
47	1855	Services (Overhead & Underground)	$ 347,728	$ 9,958	-$ 259	$ 357,427	-$ 83,001	-$ 16,320	$ 259	-$ 99,062	$ 258,365
47	1860	Meters	$ 23,379	$ 16,227		$ 39,606	-$ 11,558	-$ 1,545		-$ 13,103	$ 26,503
47	1860	Meters (Smart Meters)	$ 689,836	$ 14,472		$ 704,308	-$ 367,798	-$ 61,935		-$ 429,734	$ 274,574
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 469			$ 469	-$ 469			-$ 469	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 8,225			$ 8,225	-$ 3,575	-$ 1,136		-$ 4,712	$ 3,513
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 25,924			$ 25,924	-$ 19,256	-$ 3,580		-$ 22,836	$ 3,089
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364			$ 348,364	-$ 200,384	-$ 32,885		-$ 233,268	$ 115,095
10	1930	Transportation Equipment	$ 1,550,616	$ 60,387		$ 1,611,003	-$ 1,167,953	-$ 147,819		-$ 1,315,771	$ 295,232
8	1935	Stores Equipment	$ 876			$ 876	-$ 876			-$ 876	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 91,173			$ 91,173	-$ 83,369	-$ 2,010		-$ 85,378	$ 5,795
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 15,050			$ 15,050	-$ 8,118	-$ 2,773		-$ 10,891	$ 4,159
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 155,283			-$ 155,283	$ 15,123	$ 3,566		$ 18,689	-$ 136,594
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 10,254,916**	**$ 630,867**	**-$ 11,548**	**$ 10,874,235**	**-$ 3,483,425**	**-$ 532,023**	**$ 5,398**	**-$ 4,010,049**	**$ 6,864,186**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 10,254,916**	**$ 630,867**	**-$ 11,548**	**$ 10,874,235**	**-$ 3,483,425**	**-$ 532,023**	**$ 5,398**	**-$ 4,010,049**	**$ 6,864,186**
		Construction Work In Progress	$ 232,532	$ 205,863		$ 438,394				$ -	$ 438,394
		Total PP&E	**$ 10,487,447**	**$ 836,730**	**-$ 11,548**	**$ 11,312,629**	**-$ 3,483,425**	**-$ 532,023**	**$ 5,398**	**-$ 4,010,049**	**$ 7,302,580**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-6149.77			
		Total						**-$ 538,172**			

Less: *Fully Allocated Depreciation*

10		Transportation	Transportation	-$ 147,819
8		Stores Equipment	Stores Equipment	-$ 19,373
47		Deferred Revenue	Deferred Revenue	$ 3,566
			Net Depreciation	**-$ 374,547**

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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**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 495,381			$ 495,381	-$ 300,897	-$ 70,127		-$ 371,024	$ 124,357
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700	$ -			$ -	$ 87,700
47	1808	Buildings	$ 462,385			$ 462,385	-$ 136,992	-$ 19,373		-$ 156,365	$ 306,020
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 418,536	$ 10,641		$ 429,176	-$ 115,184	-$ 11,624		-$ 126,808	$ 302,368
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,173,798	$ 206,428	-$ 9,622	$ 3,370,604	-$ 789,776	-$ 79,678	$ 4,124	-$ 865,330	$ 2,505,275
47	1835	Overhead Conductors & Devices	$ 2,089,024	$ 159,346	-$ 1,590	$ 2,246,780	-$ 294,333	-$ 58,444	$ 689	-$ 352,087	$ 1,894,693
47	1840	Underground Conduit	$ 194,407			$ 194,407	-$ 11,627	-$ 4,155		-$ 15,782	$ 178,625
47	1845	Underground Conductors & Devices	$ 8,998			$ 8,998	-$ 2,538	-$ 155		-$ 2,693	$ 6,304
47	1850	Line Transformers	$ 896,861	$ 89,437	-$ 3,346	$ 982,952	-$ 161,290	-$ 29,481	$ 1,472	-$ 189,299	$ 793,653
47	1855	Services (Overhead & Underground)	$ 357,427	$ 17,163		$ 374,590	-$ 99,062	-$ 16,684		-$ 115,746	$ 258,845
47	1860	Meters	$ 39,606			$ 39,606	-$ 13,103	-$ 1,823		-$ 14,926	$ 24,680
47	1860	Meters (Smart Meters)	$ 704,308	$ 43,959		$ 748,268	-$ 429,734	-$ 63,883		-$ 493,617	$ 254,651
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 469			$ 469	-$ 469			-$ 469	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 8,225			$ 8,225	-$ 4,712	-$ 1,078		-$ 5,789	$ 2,436
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 25,924			$ 25,924	-$ 22,836	-$ 2,006		-$ 24,842	$ 1,082
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364			$ 348,364	-$ 233,268	-$ 32,885		-$ 266,153	$ 82,211
10	1930	Transportation Equipment	$ 1,611,003			$ 1,611,003	-$ 1,315,771	-$ 103,040		-$ 1,418,811	$ 192,192
8	1935	Stores Equipment	$ 876			$ 876	-$ 876			-$ 876	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 91,173			$ 91,173	-$ 85,378	-$ 1,576		-$ 86,954	$ 4,219
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 15,050			$ 15,050	-$ 10,891	-$ 2,773		-$ 13,664	$ 1,386
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 155,283			-$ 155,283	$ 18,689	$ 3,566		$ 22,254	-$ 133,028
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 10,874,235**	**$ 526,974**	**-$ 14,558**	**$ 11,386,651**	**-$ 4,010,049**	**-$ 495,217**	**$ 6,286**	**-$ 4,498,981**	**$ 6,887,671**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 10,874,235**	**$ 526,974**	**-$ 14,558**	**$ 11,386,651**	**-$ 4,010,049**	**-$ 495,217**	**$ 6,286**	**-$ 4,498,981**	**$ 6,887,671**
		Construction Work In Progress	$ 438,394	$ 331,835		$ 770,229				$ -	$ 770,229
		Total PP&E	**$ 11,312,629**	**$ 858,809**	**-$ 14,558**	**$ 12,156,881**	**-$ 4,010,049**	**-$ 495,217**	**$ 6,286**	**-$ 4,498,981**	**$ 7,657,900**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-8271.94			
		Total						**-$ 503,489**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 103,040
8		Stores Equipment	Stores Equipment	-$ 19,373
47		Deferred Revenue	Deferred Revenue	$ 3,566
			Net Depreciation	**-$ 384,642**

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Year **2022**

			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**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 495,381			$ 495,381	-$ 371,024	-$ 70,127		-$ 441,152	$ 54,230
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700	$ -			$ -	$ 87,700
47	1808	Buildings	$ 462,385	$ 21,623		$ 484,008	-$ 156,365	-$ 19,914		-$ 176,278	$ 307,729
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 429,176	$ -		$ 429,176	-$ 126,808	-$ 11,746		-$ 138,555	$ 290,622
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,370,604	$ 190,698	-$ 7,768	$ 3,553,534	-$ 865,330	-$ 83,302	$ 4,060	-$ 944,572	$ 2,608,962
47	1835	Overhead Conductors & Devices	$ 2,246,780	$ 130,253	-$ 1,216	$ 2,375,818	-$ 352,087	-$ 61,605	$ 615	-$ 413,077	$ 1,962,741
47	1840	Underground Conduit	$ 194,407			$ 194,407	-$ 15,782	-$ 4,155		-$ 19,937	$ 174,470
47	1845	Underground Conductors & Devices	$ 8,998			$ 8,998	-$ 2,693	-$ 155		-$ 2,848	$ 6,150
47	1850	Line Transformers	$ 982,952	$ 65,128	-$ 633	$ 1,047,447	-$ 189,299	-$ 31,136	$ 279	-$ 220,156	$ 827,292
47	1855	Services (Overhead & Underground)	$ 374,590			$ 374,590	-$ 115,746	-$ 16,872		-$ 132,617	$ 241,973
47	1860	Meters	$ 39,606			$ 39,606	-$ 14,926	-$ 1,532		-$ 16,457	$ 23,149
47	1860	Meters (Smart Meters)	$ 748,268	$ 6,033		$ 754,301	-$ 493,617	-$ 65,550		-$ 559,166	$ 195,134
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 469			$ 469	-$ 469			-$ 469	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 8,225	$ 25,505		$ 33,730	-$ 5,789	-$ 2,899		-$ 8,689	$ 25,041
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 25,924	$ 6,843		$ 32,768	-$ 24,842	-$ 1,117		-$ 25,960	$ 6,808
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364			$ 348,364	-$ 266,153	-$ 32,885		-$ 299,037	$ 49,326
10	1930	Transportation Equipment	$ 1,611,003	$ 213,425	-$ 63,985	$ 1,760,443	-$ 1,418,811	-$ 86,213	$ 63,029	-$ 1,441,996	$ 318,447
8	1935	Stores Equipment	$ 876			$ 876	-$ 876			-$ 876	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 91,173	$ 2,385		$ 93,559	-$ 86,954	-$ 1,280		-$ 88,234	$ 5,325
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 15,050			$ 15,050	-$ 13,664	-$ 1,386		-$ 15,050	-$ 0
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue [5]	-$ 155,283			-$ 155,283	$ 22,254	$ 3,566		$ 25,820	-$ 129,462
	2005	Property Under Finance Lease [7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 11,386,651**	**$ 661,894**	**-$ 73,601**	**$ 11,974,944**	**-$ 4,498,981**	**-$ 488,308**	**$ 67,983**	**-$ 4,919,306**	**$ 7,055,638**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 11,386,651**	**$ 661,894**	**-$ 73,601**	**$ 11,974,944**	**-$ 4,498,981**	**-$ 488,308**	**$ 67,983**	**-$ 4,919,306**	**$ 7,055,638**
		Construction Work In Progress	$ 770,229	$ 284,926		$ 1,055,155				$ -	$ 1,055,155
		Total PP&E	**$ 12,156,881**	**$ 946,820**	**-$ 73,601**	**$ 13,030,099**	**-$ 4,498,981**	**-$ 488,308**	**$ 67,983**	**-$ 4,919,306**	**$ 8,110,793**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]						-5618.58			
		Total						**-$ 493,926**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 86,213
8		Stores Equipment	Stores Equipment	-$ 19,914
47		Deferred Revenue	Deferred Revenue	$ 3,566
			Net Depreciation	**-$ 391,365**

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			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
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 495,381	$ 57,580		$ 552,961	-$ 441,152	-$ 47,437		-$ 488,588	$ 64,373
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700			$ 87,700	$ -			$ -	$ 87,700
47	1808	Buildings	$ 484,008	$ 4,270		$ 488,278	-$ 176,278	-$ 20,525		-$ 196,804	$ 291,474
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 429,176			$ 429,176	-$ 138,555	-$ 11,748		-$ 150,303	$ 278,874
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,553,534	$ 52,550	-$ 12,080	$ 3,594,004	-$ 944,572	-$ 85,375	$ 3,054	-$ 1,026,894	$ 2,567,110
47	1835	Overhead Conductors & Devices	$ 2,375,818	$ 46,530		$ 2,422,349	-$ 413,077	-$ 63,606		-$ 476,683	$ 1,945,666
47	1840	Underground Conduit	$ 194,407			$ 194,407	-$ 19,937	-$ 4,155		-$ 24,091	$ 170,316
47	1845	Underground Conductors & Devices	$ 8,998			$ 8,998	-$ 2,848	-$ 155		-$ 3,003	$ 5,995
47	1850	Line Transformers	$ 1,047,447	$ 21,602	-$ 263	$ 1,068,787	-$ 220,156	-$ 32,087	$ 133	-$ 252,109	$ 816,677
47	1855	Services (Overhead & Underground)	$ 374,590			$ 374,590	-$ 132,617	-$ 16,872		-$ 149,489	$ 225,101
47	1860	Meters	$ 39,606	$ 15,705		$ 55,311	-$ 16,457	-$ 1,846		-$ 18,303	$ 37,008
47	1860	Meters (Smart Meters)	$ 754,301	$ 19,335		$ 773,636	-$ 559,166	-$ 66,395		-$ 625,561	$ 148,075
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 469			$ 469	-$ 469			-$ 469	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 33,730			$ 33,730	-$ 8,689	-$ 4,592		-$ 13,281	$ 20,449
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ 32,768	-$ 32,768		$ -	-$ 25,960	$ 25,960		$ 0	$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364	$ 41,264		$ 389,627	-$ 299,037	-$ 61,495		-$ 360,533	$ 29,095
10	1930	Transportation Equipment	$ 1,760,443	$ 118,513		$ 1,878,956	-$ 1,441,996	-$ 84,292		-$ 1,526,288	$ 352,668
8	1935	Stores Equipment	$ 876			$ 876	-$ 876			-$ 876	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 93,559	$ 4,500		$ 98,059	-$ 88,234	-$ 1,361		-$ 89,595	$ 8,464
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -			$ -	$ -			$ -	$ -
8	1955	Communications Equipment	$ 15,050			$ 15,050	-$ 15,050			-$ 15,050	-$ 0
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 155,283			-$ 155,283	$ 25,820	$ 3,566		$ 29,386	-$ 125,897
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 11,974,944**	**$ 349,082**	**-$ 12,343**	**$ 12,311,683**	**-$ 4,919,306**	**-$ 472,414**	**$ 3,186**	**-$ 5,388,533**	**$ 6,923,150**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 11,974,944**	**$ 349,082**	**-$ 12,343**	**$ 12,311,683**	**-$ 4,919,306**	**-$ 472,414**	**$ 3,186**	**-$ 5,388,533**	**$ 6,923,150**
		Construction Work In Progress	$ 1,055,155	$ 439,682	-$ 62,225	$ 1,432,612				$ -	$ 1,432,612
		Total PP&E	**$ 13,030,099**	**$ 788,764**	**-$ 74,568**	**$ 13,744,295**	**-$ 4,919,306**	**-$ 472,414**	**$ 3,186**	**-$ 5,388,533**	**$ 8,355,762**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]						-9157			
		Total						**-$ 481,571**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 84,292
8		Stores Equipment	Stores Equipment	-$ 20,525
47		Deferred Revenue	Deferred Revenue	-$ 3,566
			Net Depreciation	**-$ 373,188**

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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
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 552,961	$ 891,605		$ 1,444,566	-$ 488,588	-$ 81,495		-$ 570,083	$ 874,483
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 87,700	$ 85,000		$ 172,700	$ -			$ -	$ 172,700
47	1808	Buildings	$ 488,278			$ 488,278	-$ 196,804	-$ 20,597		-$ 217,400	$ 270,878
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 429,176	$ 485,747		$ 914,923	-$ 150,303	-$ 13,999		-$ 164,301	$ 750,622
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,594,004	$ 257,863		$ 3,851,867	-$ 1,026,894	-$ 87,331		-$ 1,114,225	$ 2,737,643
47	1835	Overhead Conductors & Devices	$ 2,422,349	$ 148,382		$ 2,570,731	-$ 476,683	-$ 64,490		-$ 541,173	$ 2,029,558
47	1840	Underground Conduit	$ 194,407			$ 194,407	-$ 24,091	-$ 4,155		-$ 28,246	$ 166,161
47	1845	Underground Conductors & Devices	$ 8,998	$ 71,200		$ 80,198	-$ 3,003	-$ 946		-$ 3,949	$ 76,249
47	1850	Line Transformers	$ 1,068,787	$ 349,613		$ 1,418,399	-$ 252,109	-$ 33,126		-$ 285,235	$ 1,133,164
47	1855	Services (Overhead & Underground)	$ 374,590	$ 72,920		$ 447,510	-$ 149,489	-$ 17,601		-$ 167,090	$ 280,421
47	1860	Meters	$ 55,311			$ 55,311	-$ 18,303	-$ 2,160		-$ 20,463	$ 34,848
47	1860	Meters (Smart Meters)	$ 773,636			$ 773,636	-$ 625,561	-$ 47,169		-$ 672,730	$ 100,906
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 469			$ 469	-$ 469			-$ 469	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 33,730			$ 33,730	-$ 13,281	-$ 4,053		-$ 17,334	$ 16,396
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ 0			$ 0	$ 0
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 389,627	$ 25,000		$ 414,627	-$ 360,533	-$ 22,227		-$ 382,759	$ 31,868
10	1930	Transportation Equipment	$ 1,878,956	$ 410,754		$ 2,289,710	-$ 1,526,288	-$ 100,354		-$ 1,626,642	$ 663,068
8	1935	Stores Equipment	$ 876			$ 876	-$ 876			-$ 876	$ 0
8	1940	Tools, Shop & Garage Equipment	$ 98,059			$ 98,059	-$ 89,595	-$ 1,553		-$ 91,148	$ 6,911
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ -	$ 86,200		$ 86,200	$ -	-$ 4,310		-$ 4,310	$ 81,890
8	1955	Communications Equipment	$ 15,050			$ 15,050	-$ 15,050			-$ 15,050	-$ 0
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue [5]	-$ 155,283			-$ 155,283	$ 29,386	$ 3,566		$ 32,952	-$ 122,331
	2005	Property Under Finance Lease [7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 12,311,683**	**$ 2,884,284**	**$ -**	**$ 15,195,967**	**-$ 5,388,533**	**-$ 501,998**	**$ -**	**-$ 5,890,532**	**$ 9,305,435**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 12,311,683**	**$ 2,884,284**	**$ -**	**$ 15,195,967**	**-$ 5,388,533**	**-$ 501,998**	**$ -**	**-$ 5,890,532**	**$ 9,305,435**
		Construction Work In Progress	$ 1,432,612	$ 463,870	-$ 1,309,240	$ 587,242				$ -	$ 587,242
		Total PP&E	**$ 13,744,295**	**$ 3,348,154**	**-$ 1,309,240**	**$ 15,783,209**	**-$ 5,388,533**	**-$ 501,998**	**$ -**	**-$ 5,890,532**	**$ 9,892,677**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable [6]									
		Total						**-$ 501,998**			

CCA Class	OEB Account	Description	**Less:** *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 100,354
8		Stores Equipment	Stores Equipment	-$ 20,597
47		Deferred Revenue	Deferred Revenue	-$ 3,566
			Net Depreciation	**-$ 377,482**

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Accounting Standard MIFRS
Year **2025**

			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**
	1609	Capital Contributions Paid	$ -			$ -	$ -			$ -	$ -
12	1611	Computer Software (Formally known as Account 1925)	$ 1,444,566	$ 20,000		$ 1,464,566	-$ 570,083	-$ 138,241		-$ 708,324	$ 756,241.52
CEC	1612	Land Rights (Formally known as Account 1906)	$ -			$ -	$ -			$ -	$ -
N/A	1805	Land	$ 172,700			$ 172,700	$ -			$ -	$ 172,700.35
47	1808	Buildings	$ 488,278	$ 30,000		$ 518,278	-$ 217,400	-$ 21,347		-$ 238,747	$ 279,531.13
13	1810	Leasehold Improvements	$ -			$ -	$ -			$ -	$ -
47	1815	Transformer Station Equipment >50 kV	$ -			$ -	$ -			$ -	$ -
47	1820	Distribution Station Equipment <50 kV	$ 914,923			$ 914,923	-$ 164,301	-$ 16,640		-$ 180,941	$ 733,982.08
47	1825	Storage Battery Equipment	$ -			$ -	$ -			$ -	$ -
47	1830	Poles, Towers & Fixtures	$ 3,851,867	$ 892,641		$ 4,744,508	-$ 1,114,225	-$ 98,959		-$ 1,213,183	$ 3,531,324.53
47	1835	Overhead Conductors & Devices	$ 2,570,731	$ 577,877		$ 3,148,608	-$ 541,173	-$ 71,275		-$ 612,448	$ 2,536,160.37
47	1840	Underground Conduit	$ 194,407			$ 194,407	-$ 28,246	-$ 4,155		-$ 32,401	$ 162,006.34
47	1845	Underground Conductors & Devices	$ 80,198			$ 80,198	-$ 3,949	-$ 1,755		-$ 5,704	$ 74,493.97
47	1850	Line Transformers	$ 1,418,399	$ 277,407		$ 1,695,807	-$ 285,235	-$ 37,015		-$ 322,250	$ 1,373,557.03
47	1855	Services (Overhead & Underground)	$ 447,510			$ 447,510	-$ 167,090	-$ 8,208		-$ 175,298	$ 272,212.72
47	1860	Meters	$ 55,311			$ 55,311	-$ 20,463	-$ 2,160		-$ 22,623	$ 32,688.29
47	1860	Meters (Smart Meters)	$ 773,636	$ 15,000		$ 788,636	-$ 672,730	-$ 24,264		-$ 696,994	$ 91,642.45
N/A	1905	Land	$ -			$ -	$ -			$ -	$ -
47	1908	Buildings & Fixtures	$ -			$ -	$ -			$ -	$ -
13	1910	Leasehold Improvements	$ 469			$ 469	-$ 469			-$ 469	$ -
8	1915	Office Furniture & Equipment (10 years)	$ 33,730			$ 33,730	-$ 17,334	-$ 3,644		-$ 20,978	$ 12,752.50
8	1915	Office Furniture & Equipment (5 years)	$ -			$ -	$ -			$ -	$ -
10	1920	Computer Equipment - Hardware	$ -			$ -	$ 0			$ 0	$ 0.00
45	1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -			$ -	$ -			$ -	$ -
50	1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 414,627	$ 5,000		$ 419,627	-$ 382,759	-$ 8,568		-$ 391,327	$ 28,300.53
10	1930	Transportation Equipment	$ 2,289,710			$ 2,289,710	-$ 1,626,642	-$ 115,089		-$ 1,741,731	$ 547,978.64
8	1935	Stores Equipment	$ 876			$ 876	-$ 876			-$ 876	$ 0.03
8	1940	Tools, Shop & Garage Equipment	$ 98,059	$ 9,000		$ 107,059	-$ 91,148	-$ 2,003		-$ 93,151	$ 13,907.74
8	1945	Measurement & Testing Equipment	$ -			$ -	$ -			$ -	$ -
8	1950	Power Operated Equipment	$ 86,200			$ 86,200	-$ 4,310	-$ 8,620		-$ 12,930	$ 73,270.00
8	1955	Communications Equipment	$ 15,050			$ 15,050	-$ 15,050			-$ 15,050	-$ 0.01
8	1955	Communication Equipment (Smart Meters)	$ -			$ -	$ -			$ -	$ -
8	1960	Miscellaneous Equipment	$ -			$ -	$ -			$ -	$ -
47	1970	Load Management Controls Customer Premises	$ -			$ -	$ -			$ -	$ -
47	1975	Load Management Controls Utility Premises	$ -			$ -	$ -			$ -	$ -
47	1980	System Supervisor Equipment	$ -			$ -	$ -			$ -	$ -
47	1985	Miscellaneous Fixed Assets	$ -			$ -	$ -			$ -	$ -
47	1990	Other Tangible Property	$ -			$ -	$ -			$ -	$ -
47	1995	Contributions & Grants	$ -			$ -	$ -			$ -	$ -
47	2440	Deferred Revenue[5]	-$ 155,283			-$ 155,283	$ 32,952	$ 3,566		$ 36,518	-$ 118,764.81
	2005	Property Under Finance Lease[7]	$ -			$ -	$ -			$ -	$ -
		Sub-Total	**$ 15,195,967**	**$ 1,826,925**	**$ -**	**$ 17,022,892**	**-$ 5,890,532**	**-$ 558,374**	**$ -**	**-$ 6,448,906**	**$ 10,573,985**
		Less Socialized Renewable Energy Generation Investments (input as negative)				$ -				$ -	$ -
		Less Other Non Rate-Regulated Utility Assets (input as negative)				$ -				$ -	$ -
		Total PP&E for Rate Base Purposes	**$ 15,195,967**	**$ 1,826,925**	**$ -**	**$ 17,022,892**	**-$ 5,890,532**	**-$ 558,374**	**$ -**	**-$ 6,448,906**	**$ 10,573,985**
		Construction Work In Progress	$ 587,242			$ 587,242				$ -	$ 587,242
		Total PP&E	**$ 15,783,209**	**$ 1,826,925**	**$ -**	**$ 17,610,134**	**-$ 5,890,532**	**-$ 558,374**	**$ -**	**-$ 6,448,906**	**$ 11,161,228**
		Depreciation Expense adj. from gain or loss on the retirement of assets (pool of like assets), if applicable[6]									
		Total						**-$ 558,374**			

			Less: *Fully Allocated Depreciation*	
10		Transportation	Transportation	-$ 93,187
8		Stores Equipment	Stores Equipment	-$ 24,347
47		Deferred Revenue	Deferred Revenue	-$ 3,566
			Net Depreciation	**-$ 437,275**

GROSS ASSETS (PP&E)

NOW Inc.'s Fixed Asset Continuity Statements containing both costs and depreciation for historic years 2017 to 2023 and for Bridge Year 2024 and Test Year 2025 are provided in E2/T1/S1/Att1. The figures in the Bridge and Test Year are representative of the capital expenditure programs in both cases.

NOW Inc. utilizes the straight-line method in calculating depreciation for all capital assets. The estimated useful life is the driver for the calculation, and impairments are evaluated each year. In calculating depreciation of current year additions, NOW Inc. employs the half-year rule.

DEPRECIATION EXPENSE & POLICY

Since 2013, NOW Inc.'s depreciation has been consistent with MIFRS. Under MIFRS, costs are depreciated over the useful life of the asset. These values are consistent with the Fixed Asset Continuity Schedules in E2/T1/S1/Att1 which is OEB Appendix 2-BA.

Depreciation expense from 2017 Board Approved to 2025 TY is presented in **Table 1**.

Table 1

Annual Depreciation Expense for Rate-Setting Purposes

			Historical						Bridge	Test
	2017 Approved	2017	2018	2019	2020	2021	2022	2023	2024	2025
Accounting Standard	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Total Depreciation	648,399	640,219	634,643	568,857	538,173	503,489	493,926	481,571	501,998	558,375
Fully Allocated Depreciation	-209,522	-206,051	-188,715	-189,866	-163,626	-118,847	-102,561	-101,251	-117,385	-113,968
Net Depreciation	**$ 438,877**	**$ 434,168**	**$ 445,928**	**$ 378,991**	**$ 374,547**	**$ 384,642**	**$ 391,365**	**$ 380,320**	**$ 384,613**	**$ 444,407**

Following a decline in depreciation expense from 2017 to 2020, depreciation has increased to the 2025 Test Year where it is in line with depreciation from the 2017 approved amount. NOW Inc.'s depreciation has increased in recent years at a lower rate than rate base because a higher proportion of capital investments have been assets with longer useful lives. Additionally, capital expenditures have increased in 2024 and 2025 so a higher proportion of its gross assets has a low amount of accumulated depreciation.

DEPRECIATION POLICY

NOW Inc.'s depreciation practices follow OEB depreciation guidelines. NOW Inc. groups fixed assets in accordance with MIFRS standards with major components of PP&E being depreciated separately.

NOW Inc. does not have a formal depreciation policy and has not made any changes to its depreciation practices or service lives since its last rate application for 2017 rates. NOW Inc. follows the Kinectrics Report with respect to asset service lives.

NOW Inc. uses the half-year rule for the purposes of calculating depreciation expense. The half-year rule has been applied to all capital additions in the 2025 Test Year.

Construction Work in Progress assets are not depreciated until the asset is in service.

NOW Inc. is not filing any ARO's as part of this application.

NOW Inc.'s depreciation expense for 2017 to 2025 is provided in E2/T1/S3/Att1 - OEB Appendix 2-C.

Attachment 1 (of 1):

OEB Appendix 2-C

Appendix 2-C
Depreciation and Amortization Expense

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

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

Year 2017

		Book Values				Service Lives		Depreciation Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid					$ -		0.00%	$ -	$ -	$ -
1611	Computer Software (Formally known as Account 1925)	$ 427,908	$ 79,461	$ 97,120	$ 48,167	$ 348,840	5.00	20.00%	$ 69,768	$ 60,544	-$ 9,224
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1805	Land	$ 87,700	$ -	$ -	$ -	$ 87,700		0.00%	$ -	$ -	$ -
1808	Buildings	$ 462,385	$ 59,500	$ -	$ -	$ 402,885	20.00	5.00%	$ 20,144	$ 19,373	-$ 771
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1820	Distribution Station Equipment <50 kV	$ 274,445	$ 60,301	$ 43,548	$ -	$ 235,918	17.00	5.88%	$ 13,878	$ 22,272	$ 8,395
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1830	Poles, Towers & Fixtures	$ 2,231,239	$ 377,356	$ 283,268	$ 6,913	$ 1,988,604	23.00	4.35%	$ 86,461	$ 136,140	$ 49,679
1835	Overhead Conductors & Devices	$ 1,291,475	$ 106,106	$ 241,402	$ 1,953	$ 1,304,117	31.00	3.23%	$ 42,068	$ 42,478	$ 409
1840	Underground Conduit	$ 9,548	$ 4,092	$ -	$ -	$ 5,456	4.00	25.00%	$ 1,364	$ 1,364	$ 0
1845	Underground Conductors & Devices	$ 2,110	$ 904	$ 4,376	$ -	$ 3,394	12.00	8.33%	$ 283	$ 350	$ 67
1850	Line Transformers	$ 621,414	$ 59,203	$ 61,221	$ 1,907	$ 590,914	27.00	3.70%	$ 21,886	$ 23,681	$ 1,795
1855	Services (Overhead & Underground)	$ 238,324	$ 33,382	$ 55,543	$ -	$ 232,713	17.00	5.88%	$ 13,689	$ 14,011	$ 322
1860	Meters	$ 21,583	$ 6,684	$ -	$ -	$ 14,900	10.00	10.00%	$ 1,490	$ 1,964	$ 474
1860	Meters (Smart Meters)	$ 675,238	$ 184,781	$ 1,770	$ -	$ 491,341	8.00	12.50%	$ 61,418	$ 60,539	-$ 879
1905	Land	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1910	Leasehold Improvements	$ 469	$ 469	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1915	Office Furniture & Equipment (10 years)	$ 2,489	$ 573	$ 5,736	$ -	$ 4,785	7.00	14.29%	$ 684	$ 728	$ 44
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equipment - Hardware	$ 25,760	$ 8,298	$ -	$ -	$ 17,462	2.50	40.00%	$ 6,985	$ 5,447	-$ 1,538
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364	$ 101,730	$ -	$ -	$ 246,633	7.50	13.33%	$ 32,884	$ 32,885	$ 0
1930	Transportation Equipment	$ 1,362,830	$ 660,592	$ -	$ 33,141	$ 669,097	3.50	28.57%	$ 191,170	$ 190,149	-$ 1,021
1935	Stores Equipment	$ 876	$ 740	$ -	$ -	$ 136	1.50	66.67%	$ 91	$ 68	-$ 23
1940	Tools, Shop & Garage Equipment	$ 88,863	$ 64,618	$ 2,311	$ -	$ 25,400	2.50	40.00%	$ 10,160	$ 10,430	$ 269
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1955	Communications Equipment	$ 1,186	$ 1,186	$ 13,865	$ -	$ 6,932	5.00	20.00%	$ 1,386	$ 1,386	-$ 0
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -		0.00%	$ -	$ -	$ -
2440	Deferred Revenue	-$ 146,961	-$ 4,520	-$ 8,321	$ -	-$ 146,602	35.00	2.86%	-$ 4,189	-$ 3,471	$ 717
2005	Property Under Finance Lease					$ -		0.00%	$ -	$ -	$ -
	Total	$ 8,027,245	$ 1,805,457	$ 801,837	$ 92,081	$ 6,530,626	$ 239		$ 571,620	$ 620,336	$ 48,716

Year 2018

		Book Values				Service Lives		Depreciation Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid					$ -		0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 476,861	$ 91,838	$ 18,521	$ -	$ 394,283	4.50	22.22%	**$ 87,618**	$ 68,804	**-$ 18,814**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 87,700	$ -	$ -	$ -	$ 87,700	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 462,385	$ 78,873	$ -	$ -	$ 383,512	19.00	5.26%	**$ 20,185**	$ 19,373	**-$ 812**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 317,993	$ 82,573	$ 87,882	$ -	$ 279,361	16.00	6.25%	**$ 17,460**	$ 9,843	**-$ 7,617**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 2,507,594	$ 509,503	$ 281,138	$ 4,932	$ 2,133,729	22.00	4.55%	**$ 96,988**	$ 142,463	**$ 45,476**
1835	Overhead Conductors & Devices	$ 1,530,924	$ 147,225	$ 230,992	$ 8,495	$ 1,490,699	30.00	3.33%	**$ 49,690**	$ 47,681	**-$ 2,009**
1840	Underground Conduit	$ 9,548	$ 5,456	$ -	$ -	$ 4,092	3.00	33.33%	**$ 1,364**	$ 1,364	**-$ 0**
1845	Underground Conductors & Devices	$ 6,486	$ 1,255	$ -	$ -	$ 5,232	11.00	9.09%	**$ 476**	$ 400	**-$ 76**
1850	Line Transformers	$ 680,729	$ 82,510	$ 101,231	$ 1,980	$ 646,854	26.00	3.85%	**$ 24,879**	$ 25,581	**$ 702**
1855	Services (Overhead & Underground)	$ 293,867	$ 47,393	$ 26,855	$ -	$ 259,901	16.00	6.25%	**$ 16,244**	$ 19,620	**$ 3,377**
1860	Meters	$ 21,583	$ 8,647	$ -	$ -	$ 12,936	9.00	11.11%	**$ 1,437**	$ 1,726	**$ 289**
1860	Meters (Smart Meters)	$ 677,007	$ 245,320	$ 12,829	$ -	$ 438,102	7.00	14.29%	**$ 62,586**	$ 61,025	**-$ 1,561**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ 469	$ 469	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 8,225	$ 1,300	$ -	$ -	$ 6,925	6.00	16.67%	**$ 1,154**	$ 1,137	**-$ 17**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 25,760	$ 13,745	$ -	$ -	$ 12,015	1.50	66.67%	**$ 8,010**	$ 4,147	**-$ 3,863**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364	$ 134,615	$ -	$ -	$ 213,749	6.50	15.38%	**$ 32,884**	$ 32,885	**$ 0**
1930	Transportation Equipment	$ 1,329,689	$ 820,985	$ 85,492	$ -	$ 551,450	3.50	28.57%	**$ 157,557**	$ 172,908	**$ 15,351**
1935	Stores Equipment	$ 876	$ 808	$ -	$ -	$ 68	-	0.00%	**$ -**	$ 68	**$ 68**
1940	Tools, Shop & Garage Equipment	$ 91,173	$ 75,047	$ -	$ -	$ 16,126	1.50	66.67%	**$ 10,751**	$ 5,561	**-$ 5,190**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 15,050	$ 2,572	$ -	$ -	$ 12,478	4.00	25.00%	**$ 3,120**	$ 2,773	**-$ 347**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 155,283	-$ 7,991	$ -	$ -	-$ 147,292	34.00	2.94%	**-$ 4,332**	-$ 3,566	**$ 766**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 8,737,001**	**$ 2,342,144**	**$ 844,940**	**$ 15,407**	**$ 6,801,920**	**$ 221**		**$ 588,070**	**$ 613,794**	**$ 25,723**

Year 2019

		Book Values				Service Lives		Depreciation Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid					$ -		0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 495,381	$ 160,642	$ -	$ -	$ 334,739	3.50	28.57%	**$ 95,640**	$ 70,127	**-$ 25,512**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 87,700	$ -	$ -	$ -	$ 87,700	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 462,385	$ 98,246	$ -	$ -	$ 364,139	18.00	5.56%	**$ 20,230**	$ 19,373	**-$ 857**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 405,875	$ 92,416	$ 12,661	$ -	$ 319,789	15.00	6.67%	**$ 21,319**	$ 11,263	**-$ 10,056**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 2,783,800	$ 648,994	$ 230,001	$ 12,933	$ 2,236,874	25.00	4.00%	**$ 89,475**	$ 76,505	**-$ 12,970**
1835	Overhead Conductors & Devices	$ 1,753,421	$ 192,876	$ 205,421	$ 14,390	$ 1,648,865	29.00	3.45%	**$ 56,857**	$ 51,860	**-$ 4,997**
1840	Underground Conduit	$ 9,548	$ 6,820	$ 1,139	$ -	$ 3,297	2.00	50.00%	**$ 1,649**	$ 1,377	**-$ 272**
1845	Underground Conductors & Devices	$ 6,486	$ 1,654	$ 2,511	$ -	$ 6,088	10.00	10.00%	**$ 609**	$ 428	**-$ 181**
1850	Line Transformers	$ 779,980	$ 107,650	$ 106,175	$ 6,605	$ 718,812	25.00	4.00%	**$ 28,752**	$ 27,412	**-$ 1,340**
1855	Services (Overhead & Underground)	$ 320,722	$ 67,013	$ 27,006	$ -	$ 267,212	15.00	6.67%	**$ 17,814**	$ 15,988	**-$ 1,826**
1860	Meters	$ 21,583	$ 10,373	$ 1,796	$ -	$ 12,108	8.00	12.50%	**$ 1,513**	$ 1,185	**-$ 329**
1860	Meters (Smart Meters)	$ 689,836	$ 306,345	$ -	$ -	$ 383,491	6.00	16.67%	**$ 63,915**	$ 61,453	**-$ 2,462**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ 469	$ 469	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 8,225	$ 2,438	$ -	$ -	$ 5,787	5.00	20.00%	**$ 1,157**	$ 1,137	**-$ 20**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 25,760	$ 17,893	$ 2,164	$ 2,000	$ 6,950	-	0.00%	**$ -**	$ 3,363	**$ 3,363**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364	$ 167,499	$ -	$ -	$ 180,864	5.50	18.18%	**$ 32,884**	$ 32,885	**$ 0**
1930	Transportation Equipment	$ 1,415,181	$ 993,894	$ 135,435	$ -	$ 489,005	3.50	28.57%	**$ 139,716**	$ 174,059	**$ 34,343**
1935	Stores Equipment	$ 876	$ 876	$ -	$ -	$ 0	-	0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 91,173	$ 80,608	$ -	$ -	$ 10,565	-	0.00%	**$ -**	$ 2,760	**$ 2,760**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 15,050	$ 5,345	$ -	$ -	$ 9,705	3.00	33.33%	**$ 3,235**	$ 2,773	**-$ 462**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 155,283	-$ 11,557	$ -	$ -	-$ 143,726	33.00	3.03%	**-$ 4,355**	-$ 3,566	**$ 789**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 9,566,534**	**$ 2,950,496**	**$ 724,309**	**$ 35,928**	**$ 6,942,266**	**$ 207**		**$ 570,411**	**$ 550,383**	**-$ 20,028**

Year 2020

		Book Values				Service Lives		Depreciation Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid					$ -		0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 495,381	$ 230,770	$ -	$ -	$ 264,612	2.50	40.00%	**$ 105,845**	$ 70,127	**-$ 35,717**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 87,700	$ -	$ -	$ -	$ 87,700	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 462,385	$ 117,619	$ -	$ -	$ 344,766	17.00	5.88%	**$ 20,280**	$ 19,373	**-$ 907**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 418,536	$ 103,679	$ -	$ -	$ 314,857	14.00	7.14%	**$ 22,490**	$ 11,505	**-$ 10,985**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 3,000,868	$ 715,901	$ 178,885	$ 5,955	$ 2,368,455	32.00	3.13%	**$ 74,014**	$ 77,040	**$ 3,026**
1835	Overhead Conductors & Devices	$ 1,944,452	$ 240,709	$ 148,609	$ 4,036	$ 1,774,012	36.00	2.78%	**$ 49,278**	$ 55,166	**$ 5,888**
1840	Underground Conduit	$ 10,687	$ 8,197	$ 183,720	$ -	$ 94,350	35.00	2.86%	**$ 2,696**	$ 3,431	**$ 735**
1845	Underground Conductors & Devices	$ 8,998	$ 2,082	$ -	$ -	$ 6,916	9.00	11.11%	**$ 768**	$ 456	**-$ 312**
1850	Line Transformers	$ 879,549	$ 133,234	$ 18,609	$ 1,297	$ 754,323	26.00	3.85%	**$ 29,012**	$ 28,488	**-$ 525**
1855	Services (Overhead & Underground)	$ 347,728	$ 83,001	$ 9,958	$ 259	$ 269,447	18.00	5.56%	**$ 14,969**	$ 16,320	**$ 1,351**
1860	Meters	$ 23,379	$ 11,558	$ 16,227	$ -	$ 19,935	7.00	14.29%	**$ 2,848**	$ 1,545	**-$ 1,303**
1860	Meters (Smart Meters)	$ 689,836	$ 367,798	$ 14,472	$ -	$ 329,274	5.50	18.18%	**$ 59,868**	$ 61,935	**$ 2,067**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ 469	$ 469	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 8,225	$ 3,575	$ -	$ -	$ 4,650	4.00	25.00%	**$ 1,162**	$ 1,136	**-$ 26**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 25,924	$ 19,256	$ -	$ -	$ 6,668	-	0.00%	**$ -**	$ 3,580	**$ 3,580**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364	$ 200,384	$ -	$ -	$ 147,980	4.50	22.22%	**$ 32,884**	$ 32,885	**$ 0**
1930	Transportation Equipment	$ 1,550,616	$ 1,167,953	$ 60,387	$ -	$ 412,857	3.00	33.33%	**$ 137,619**	$ 147,819	**$ 10,200**
1935	Stores Equipment	$ 876	$ 876	$ -	$ -	$ 0	-	0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 91,173	$ 83,369	$ -	$ -	$ 7,805	-	0.00%	**$ -**	$ 2,010	**$ 2,010**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 15,050	$ 8,118	$ -	$ -	$ 6,932	2.00	50.00%	**$ 3,466**	$ 2,773	**-$ 693**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 155,283	-$ 15,123	$ -	$ -	-$ 140,160	32.00	3.13%	**-$ 4,380**	-$ 3,566	**$ 814**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 10,254,916**	**$ 3,483,425**	**$ 630,867**	**$ 11,548**	**$ 7,075,377**	**$ 248**		**$ 552,821**	**$ 532,023**	**-$ 20,798**

Year 2021

		Book Values				Service Lives		Depreciation Expense			
Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid					$ -		0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 495,381	$ 300,897	$ -	$ -	$ 194,484	2.00	50.00%	**$ 97,242**	$ 70,127	**-$ 27,115**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 87,700	$ -	$ -	$ -	$ 87,700	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 462,385	$ 136,992	$ -	$ -	$ 325,393	16.00	6.25%	**$ 20,337**	$ 19,373	**-$ 964**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 418,536	$ 115,184	$ 10,641	$ -	$ 308,672	17.00	5.88%	**$ 18,157**	$ 11,624	**-$ 6,533**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 3,173,798	$ 789,776	$ 206,428	$ 9,622	$ 2,477,615	36.00	2.78%	**$ 68,823**	$ 79,678	**$ 10,855**
1835	Overhead Conductors & Devices	$ 2,089,024	$ 294,333	$ 159,346	$ 1,590	$ 1,872,775	40.00	2.50%	**$ 46,819**	$ 58,444	**$ 11,625**
1840	Underground Conduit	$ 194,407	$ 11,627	$ -	$ -	$ 182,780	34.00	2.94%	**$ 5,376**	$ 4,155	**-$ 1,221**
1845	Underground Conductors & Devices	$ 8,998	$ 2,538	$ -	$ -	$ 6,459	8.00	12.50%	**$ 807**	$ 155	**-$ 653**
1850	Line Transformers	$ 896,861	$ 161,290	$ 89,437	$ 3,346	$ 776,944	30.00	3.33%	**$ 25,898**	$ 29,481	**$ 3,583**
1855	Services (Overhead & Underground)	$ 357,427	$ 99,062	$ 17,163	$ -	$ 266,947	17.00	5.88%	**$ 15,703**	$ 16,684	**$ 981**
1860	Meters	$ 39,606	$ 13,103	$ -	$ -	$ 26,503	6.00	16.67%	**$ 4,417**	$ 1,823	**-$ 2,594**
1860	Meters (Smart Meters)	$ 704,308	$ 429,734	$ 43,959	$ -	$ 296,554	7.00	14.29%	**$ 42,365**	$ 63,883	**$ 21,518**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ 469	$ 469	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 8,225	$ 4,712	$ -	$ -	$ 3,513	3.00	33.33%	**$ 1,171**	$ 1,078	**-$ 94**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 25,924	$ 22,836	$ -	$ -	$ 3,089	-	0.00%	**$ -**	$ 2,006	**$ 2,006**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364	$ 233,268	$ -	$ -	$ 115,095	3.50	28.57%	**$ 32,884**	$ 32,885	**$ 0**
1930	Transportation Equipment	$ 1,611,003	$ 1,315,771	$ -	$ -	$ 295,232	3.00	33.33%	**$ 98,411**	$ 103,040	**$ 4,629**
1935	Stores Equipment	$ 876	$ 876	$ -	$ -	$ 0	-	0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 91,173	$ 85,378	$ -	$ -	$ 5,795	-	0.00%	**$ -**	$ 1,576	**$ 1,576**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 15,050	$ 10,891	$ -	$ -	$ 4,159	1.00	100.00%	**$ 4,159**	$ 2,773	**-$ 1,386**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 155,283	-$ 18,689	$ -	$ -	-$ 136,594	31.00	3.23%	**-$ 4,406**	-$ 3,566	**$ 840**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 10,874,235**	**$ 4,010,049**	**$ 526,974**	**$ 14,558**	**$ 7,113,115**	**$ 255**		**$ 478,164**	**$ 495,217**	**$ 17,054**

Year 2022

Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix	Variance [4]
		Book Values				Service Lives		Depreciation Expense			
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid					$ -		0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 495,381	$ 371,024	$ -	$ -	$ 124,357	2.00	50.00%	**$ 62,179**	$ 70,127	**$ 7,949**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 87,700	$ -	$ -	$ -	$ 87,700	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 462,385	$ 156,365	$ 21,623	$ -	$ 316,831	15.00	6.67%	**$ 21,122**	$ 19,914	**-$ 1,209**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 429,176	$ 126,808	$ -	$ -	$ 302,368	16.00	6.25%	**$ 18,898**	$ 11,746	**-$ 7,152**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 3,370,604	$ 865,330	$ 190,698	$ 7,768	$ 2,592,856	35.00	2.86%	**$ 74,082**	$ 83,302	**$ 9,221**
1835	Overhead Conductors & Devices	$ 2,246,780	$ 352,087	$ 130,253	$ 1,216	$ 1,958,604	39.00	2.56%	**$ 50,221**	$ 61,605	**$ 11,384**
1840	Underground Conduit	$ 194,407	$ 15,782	$ -	$ -	$ 178,625	33.00	3.03%	**$ 5,413**	$ 4,155	**-$ 1,258**
1845	Underground Conductors & Devices	$ 8,998	$ 2,693	$ -	$ -	$ 6,304	7.00	14.29%	**$ 901**	$ 155	**-$ 746**
1850	Line Transformers	$ 982,952	$ 189,299	$ 65,128	$ 633	$ 825,584	29.00	3.45%	**$ 28,468**	$ 31,136	**$ 2,668**
1855	Services (Overhead & Underground)	$ 374,590	$ 115,746	$ -	$ -	$ 258,845	16.00	6.25%	**$ 16,178**	$ 16,872	**$ 694**
1860	Meters	$ 39,606	$ 14,926	$ -	$ -	$ 24,680	5.00	20.00%	**$ 4,936**	$ 1,532	**-$ 3,405**
1860	Meters (Smart Meters)	$ 748,268	$ 493,617	$ 6,033	$ -	$ 257,667	5.00	20.00%	**$ 51,533**	$ 65,550	**$ 14,016**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ 469	$ 469	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 8,225	$ 5,789	$ 25,505	$ -	$ 15,188	2.00	50.00%	**$ 7,594**	$ 2,899	**-$ 4,695**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 25,924	$ 24,842	$ 6,843	$ -	$ 4,504	-	0.00%	**$ -**	$ 1,117	**$ 1,117**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364	$ 266,153	$ -	$ -	$ 82,211	2.50	40.00%	**$ 32,884**	$ 32,885	**$ 0**
1930	Transportation Equipment	$ 1,611,003	$ 1,418,811	$ 213,425	$ 63,985	$ 234,919	3.00	33.33%	**$ 78,306**	$ 86,213	**$ 7,907**
1935	Stores Equipment	$ 876	$ 876	$ -	$ -	$ 0	-	0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 91,173	$ 86,954	$ 2,385	$ -	$ 5,412	-	0.00%	**$ -**	$ 1,280	**$ 1,280**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 15,050	$ 13,664	$ -	$ -	$ 1,386	-	0.00%	**$ -**	$ 1,386	**$ 1,386**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 155,283	-$ 22,254	$ -	$ -	-$ 133,028	30.00	3.33%	**-$ 4,434**	-$ 3,566	**$ 868**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 11,386,651**	**$ 4,498,981**	**$ 661,894**	**$ 73,601**	**$ 7,145,016**	**$ 240**		**$ 448,281**	**$ 488,308**	**$ 40,027**

Year 2023

Account	Description	Opening Book Value of Assets	Less Fully Depreciated [1]	Current Year Additions	Disposals	Net Amount of Assets to be Depreciated	Remaining Life of Assets Existing [2]	Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix	Variance [4]
		Book Values				Service Lives		Depreciation Expense			
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid					$ -		0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 495,381	$ 441,152	$ 57,580	$ -	$ 83,020	2.50	40.00%	**$ 33,208**	$ 47,437	**$ 14,229**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 87,700	$ -	$ -	$ -	$ 87,700	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 484,008	$ 176,278	$ 4,270	$ -	$ 309,864	14.00	7.14%	**$ 22,133**	$ 20,525	**-$ 1,608**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 429,176	$ 138,555	$ -	$ -	$ 290,622	15.00	6.67%	**$ 19,375**	$ 11,748	**-$ 7,627**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 3,553,534	$ 944,572	$ 52,550	$ 12,080	$ 2,623,157	34.00	2.94%	**$ 77,152**	$ 85,375	**$ 8,223**
1835	Overhead Conductors & Devices	$ 2,375,818	$ 413,077	$ 46,530	$ -	$ 1,986,006	38.00	2.63%	**$ 52,263**	$ 63,606	**$ 11,343**
1840	Underground Conduit	$ 194,407	$ 19,937	$ -	$ -	$ 174,470	32.00	3.13%	**$ 5,452**	$ 4,155	**-$ 1,298**
1845	Underground Conductors & Devices	$ 8,998	$ 2,848	$ -	$ -	$ 6,150	6.00	16.67%	**$ 1,025**	$ 155	**-$ 870**
1850	Line Transformers	$ 1,047,447	$ 220,156	$ 21,602	$ 263	$ 837,830	28.00	3.57%	**$ 29,922**	$ 32,087	**$ 2,164**
1855	Services (Overhead & Underground)	$ 374,590	$ 132,617	$ -	$ -	$ 241,973	15.00	6.67%	**$ 16,132**	$ 16,872	**$ 740**
1860	Meters	$ 39,606	$ 16,457	$ 15,705	$ -	$ 31,001	4.00	25.00%	**$ 7,750**	$ 1,846	**-$ 5,905**
1860	Meters (Smart Meters)	$ 754,301	$ 559,166	$ 19,335	$ -	$ 204,802	4.00	25.00%	**$ 51,201**	$ 66,395	**$ 15,195**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ 469	$ 469	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 33,730	$ 8,689	$ -	$ -	$ 25,041	5.00	20.00%	**$ 5,008**	$ 4,592	**-$ 416**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ 32,768	$ 25,960	-$ 32,768	$ -	-$ 9,576	-	0.00%	**$ -**	-$ 25,960	**-$ 25,960**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 348,364	$ 299,037	$ 41,264	$ -	$ 69,958	1.50	66.67%	**$ 46,639**	$ 61,495	**$ 14,856**
1930	Transportation Equipment	$ 1,760,443	$ 1,441,996	$ 118,513	$ -	$ 377,704	4.50	22.22%	**$ 83,934**	$ 84,292	**$ 358**
1935	Stores Equipment	$ 876	$ 876	$ -	$ -	$ 0	-	0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 93,559	$ 88,234	$ 4,500	$ -	$ 7,575	-	0.00%	**$ -**	$ 1,361	**$ 1,361**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1955	Communications Equipment	$ 15,050	$ 15,050	$ -	$ -	-$ 0	-	0.00%	**$ -**	$ -	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 155,283	-$ 25,820	$ -	$ -	-$ 129,462	29.00	3.45%	**-$ 4,464**	-$ 3,566	**$ 898**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 11,974,944**	**$ 4,919,306**	**$ 349,082**	**$ 12,343**	**$ 7,217,836**	**$ 233**		**$ 446,730**	**$ 472,414**	**$ 25,684**

Year 2024

Account	Description	Book Values: Opening Book Value of Assets	Book Values: Less Fully Depreciated [1]	Book Values: Current Year Additions	Book Values: Disposals	Service Lives: Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Depreciation Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid					$ -		0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 552,961	$ 488,588	$ 891,605	$ -	$ 510,175	5.00	20.00%	**$ 102,035**	$ 81,495	**-$ 20,540**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 87,700	$ -	$ 85,000	$ -	$ 130,200	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 488,278	$ 196,804	$ -	$ -	$ 291,474	13.00	7.69%	**$ 22,421**	$ 20,597	**-$ 1,825**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 429,176	$ 150,303	$ 485,747	$ -	$ 521,747	31.00	3.23%	**$ 16,831**	$ 13,999	**-$ 2,832**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 3,594,004	$ 1,026,894	$ 257,863	$ -	$ 2,696,042	41.00	2.44%	**$ 65,757**	$ 87,331	**$ 21,574**
1835	Overhead Conductors & Devices	$ 2,422,349	$ 476,683	$ 148,382	$ -	$ 2,019,857	41.00	2.44%	**$ 49,265**	$ 64,490	**$ 15,225**
1840	Underground Conduit	$ 194,407	$ 24,091	$ -	$ -	$ 170,316	31.00	3.23%	**$ 5,494**	$ 4,155	**-$ 1,339**
1845	Underground Conductors & Devices	$ 8,998	$ 3,003	$ 71,200	$ -	$ 41,595	10.00	10.00%	**$ 4,159**	$ 946	**-$ 3,214**
1850	Line Transformers	$ 1,068,787	$ 252,109	$ 349,613	$ -	$ 991,484	30.00	3.33%	**$ 33,049**	$ 33,126	**$ 76**
1855	Services (Overhead & Underground)	$ 374,590	$ 149,489	$ 72,920	$ -	$ 261,561	14.00	7.14%	**$ 18,683**	$ 17,601	**-$ 1,082**
1860	Meters	$ 55,311	$ 18,303	$ -	$ -	$ 37,008	8.00	12.50%	**$ 4,626**	$ 2,160	**-$ 2,466**
1860	Meters (Smart Meters)	$ 773,636	$ 625,561	$ -	$ -	$ 148,075	4.00	25.00%	**$ 37,019**	$ 47,169	**$ 10,150**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ 469	$ 469	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 33,730	$ 13,281	$ -	$ -	$ 20,449	4.00	25.00%	**$ 5,112**	$ 4,053	**-$ 1,059**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	-$ 0	$ -	$ -	$ 0	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 389,627	$ 360,533	$ 25,000	$ -	$ 41,595	2.50	40.00%	**$ 16,638**	$ 22,227	**$ 5,589**
1930	Transportation Equipment	$ 1,878,956	$ 1,526,288	$ 410,754	$ -	$ 558,045	5.50	18.18%	**$ 101,463**	$ 100,354	**-$ 1,108**
1935	Stores Equipment	$ 876	$ 876	$ -	$ -	$ 0	-	0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 98,059	$ 89,595	$ -	$ -	$ 8,464	-	0.00%	**$ -**	$ 1,553	**$ 1,553**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ -	$ -	$ 86,200	$ -	$ 43,100	-	0.00%	**$ -**	$ 4,310	**$ 4,310**
1955	Communications Equipment	$ 15,050	$ 15,050	$ -	$ -	-$ 0	-	0.00%	**$ -**	$ -	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 155,283	-$ 29,386	$ -	$ -	-$ 125,897	28.00	3.57%	**-$ 4,496**	-$ 3,566	**$ 930**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 12,311,683**	**$ 5,388,533**	**$ 2,884,284**	**$ -**	**$ 8,365,291**	**$ 268**		**$ 478,056**	**$ 501,998**	**$ 23,942**

Year 2025

Account	Description	Book Values: Opening Book Value of Assets	Book Values: Less Fully Depreciated [1]	Book Values: Current Year Additions	Book Values: Disposals	Service Lives: Net Amount of Assets to be Depreciated	Service Lives: Remaining Life of Assets Existing [2]	Depreciation Expense: Depreciation Rate Assets	Depreciation Expense on Assets [3]	Depreciation Expense per Appendix	Variance [4]
		a	b	c	d	e = a-b+0.5*c-d	f	g = 1/f	h = e/f	i	j = i-h
1609	Capital Contributions Paid					$ -		0.00%	**$ -**	$ -	**$ -**
1611	Computer Software (Formally known as Account 1925)	$ 1,444,566	$ 570,083	$ 20,000	$ -	$ 884,483	5.00	20.00%	**$ 176,897**	$ 138,241	**-$ 38,655**
1612	Land Rights (Formally known as Account 1906)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1805	Land	$ 172,700	$ -	$ -	$ -	$ 172,700	-	0.00%	**$ -**	$ -	**$ -**
1808	Buildings	$ 488,278	$ 217,400	$ 30,000	$ -	$ 285,878	12.00	8.33%	**$ 23,823**	$ 21,347	**-$ 2,477**
1810	Leasehold Improvements	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1815	Transformer Station Equipment >50 kV	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1820	Distribution Station Equipment <50 kV	$ 914,923	$ 164,301	$ -	$ -	$ 750,622	37.00	2.70%	**$ 20,287**	$ 16,640	**-$ 3,647**
1825	Storage Battery Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1830	Poles, Towers & Fixtures	$ 3,851,867	$ 1,114,225	$ 892,641	$ -	$ 3,183,963	44.00	2.27%	**$ 72,363**	$ 98,959	**$ 26,596**
1835	Overhead Conductors & Devices	$ 2,570,731	$ 541,173	$ 577,877	$ -	$ 2,318,497	40.00	2.50%	**$ 57,962**	$ 71,275	**$ 13,312**
1840	Underground Conduit	$ 194,407	$ 28,246	$ -	$ -	$ 166,161	30.00	3.33%	**$ 5,539**	$ 4,155	**-$ 1,384**
1845	Underground Conductors & Devices	$ 80,198	$ 3,949	$ -	$ -	$ 76,249	10.00	10.00%	**$ 7,625**	$ 1,755	**-$ 5,870**
1850	Line Transformers	$ 1,418,399	$ 285,235	$ 277,407	$ -	$ 1,271,868	34.00	2.94%	**$ 37,408**	$ 37,015	**-$ 393**
1855	Services (Overhead & Underground)	$ 447,510	$ 167,090	$ -	$ -	$ 280,421	22.00	4.55%	**$ 12,746**	$ 8,208	**-$ 4,539**
1860	Meters	$ 55,311	$ 20,463	$ -	$ -	$ 34,848	7.00	14.29%	**$ 4,978**	$ 2,160	**-$ 2,819**
1860	Meters (Smart Meters)	$ 773,636	$ 672,730	$ 15,000	$ -	$ 108,406	5.00	20.00%	**$ 21,681**	$ 24,264	**$ 2,582**
1905	Land	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1908	Buildings & Fixtures	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1910	Leasehold Improvements	$ 469	$ 469	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1915	Office Furniture & Equipment (10 years)	$ 33,730	$ 17,334	$ -	$ -	$ 16,396	3.00	33.33%	**$ 5,465**	$ 3,644	**-$ 1,822**
1915	Office Furniture & Equipment (5 years)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equipment - Hardware	$ -	-$ 0	$ -	$ -	$ 0	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 22/04)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1920	Computer Equip.-Hardware(Post Mar. 19/07)	$ 414,627	$ 382,759	$ 5,000	$ -	$ 34,368	3.50	28.57%	**$ 9,820**	$ 8,568	**-$ 1,252**
1930	Transportation Equipment	$ 2,289,710	$ 1,626,642	$ -	$ -	$ 663,068	6.00	16.67%	**$ 110,511**	$ 115,089	**$ 4,578**
1935	Stores Equipment	$ 876	$ 876	$ -	$ -	$ 0	-	0.00%	**$ -**	$ -	**$ -**
1940	Tools, Shop & Garage Equipment	$ 98,059	$ 91,148	$ 9,000	$ -	$ 11,411	-	0.00%	**$ -**	$ 2,003	**$ 2,003**
1945	Measurement & Testing Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1950	Power Operated Equipment	$ 86,200	$ 4,310	$ -	$ -	$ 81,890	-	0.00%	**$ -**	$ 8,620	**$ 8,620**
1955	Communications Equipment	$ 15,050	$ 15,050	$ -	$ -	-$ 0	-	0.00%	**$ -**	$ -	**$ -**
1955	Communication Equipment (Smart Meters)	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1960	Miscellaneous Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1970	Load Management Controls Customer Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1975	Load Management Controls Utility Premises	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1980	System Supervisor Equipment	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1985	Miscellaneous Fixed Assets	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1990	Other Tangible Property	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
1995	Contributions & Grants	$ -	$ -	$ -	$ -	$ -	-	0.00%	**$ -**	$ -	**$ -**
2440	Deferred Revenue	-$ 155,283	-$ 32,952	$ -	$ -	-$ 122,331	27.00	3.70%	**-$ 4,531**	-$ 3,566	**$ 965**
2005	Property Under Finance Lease					$ -		0.00%	**$ -**	$ -	**$ -**
	Total	**$ 15,195,967**	**$ 5,890,532**	**$ 1,826,925**		**$ 10,218,897**	**$ 286**		**$ 562,575**	**$ 558,374**	**-$ 4,201**

ALLOWANCE FOR WORKING CAPITAL

The allowance for working capital is calculated as 7.5% of the sum of Cost of Power and controllable expenses (i.e., Operations, Maintenance, Billing and Collecting, Administration and General). The commodity price estimate used to calculate the Cost of Power has been determined in a way that bases the split between RPP and non-RPP customers on actual data and uses the most current RPP price. The calculation reflects the most recent Uniform Transmission Rates approved by the Board (EB-2024-0183), issued on June 27, 2024. Should new information become available for Uniform Transmission Rates and RPP during the course of a proceeding, the Cost of Power will be updated to reflect the new rates. NOW Inc. confirms that it has not been previously directed by the Board to undertake a lead/lag study on which its current working capital allowance is based.

NOW Inc. proposes a Working Capital Allowance of $1,358,427 for the 2025 Test Year, as shown in **Table 1**.

Table 1

2025 Working Capital Allowance Calculation

Description	2025 Test
OM&A	$ 4,550,911
Cost of Power	$ 13,561,454
Working Capital	**$ 18,112,365**
Working Capital Allowance Rate	7.5%
Working Capital Allowance	**$ 1,358,427**

Table 2 below shows the working capital allowance calculation from the 2017 OEB Approved to the 2025 Test Year.

Table 2

Working Capital Allowance Calculation

Description	2017 OEB Approved	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge	2025 Test
Operations	817,472	734,009	938,481	927,458	852,226	930,035	919,278	1,025,060	999,605	1,207,276
Maintenance	565,783	495,810	440,705	488,484	639,441	536,320	702,981	743,962	980,909	1,370,467
Billing & Collecting	726,564	775,872	749,498	757,348	688,585	680,520	642,584	703,383	776,167	937,555
Administrative and General	648,087	684,299	561,156	600,844	580,818	600,521	645,920	766,468	1,047,516	1,035,613
Total Controllable Expenses	2,757,906	2,689,990	2,689,840	2,774,133	2,761,070	2,747,396	2,910,763	3,238,873	3,804,197	4,550,911
Cost of Power	16,938,090	14,849,059	13,686,932	14,509,423	15,398,378	13,568,550	13,754,113	13,397,602	13,531,578	13,561,454
Working Capital	19,695,996	17,539,049	16,376,772	17,283,556	18,159,448	16,315,946	16,664,876	16,636,475	17,335,775	18,112,365
Working Capital Allowance Rate	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	1,477,200	1,315,429	1,228,258	1,296,267	1,361,959	1,223,696	1,249,866	1,247,736	1,300,183	1,358,427

Table 3 shows that the 2025 Working Capital Allowance has decreased by $118,773 (-8.74%) as compared to the 2017 OEB approved amount. This is primarily caused by a reduction in the Cost of Power due to the Ontario Energy Rebate, partially offset by an increase in OM&A expenses.

Table 3

Change in Working Capital Allowance

Description	2017 OEB Approved	2025 Test	Change ($)	Change (%)
Cost of Power	16,938,090	13,561,454	-3,376,636	-19.9%
Controllable Expenses	2,757,906	4,550,911	1,793,005	65.0%
Working Capital	**19,695,996**	**18,112,365**	**-1,583,631**	**-8.0%**
Working Capital Allowance Rate	7.50%	7.50%		
Working Capital Allowance	**1,477,200**	**1,358,427**	**-118,772**	**-8.0%**

Exhibit 2: Rate Base

Tab 2 (of 2): Capital Expenditures

CAPITAL PLANNING

This exhibit provides information on Northern Ontario Wires capital plans. The key component of the capital planning process is the Distribution System Plan (DSP) and this is provided in E2/T2/S1, Attachment 1. The DSP has been prepared following the guidance provided in the Chapter 5 – Distribution System Plan filing requirements dated December 15, 2022. Capital expenditures are categorized based on the specified System Access, System Renewal, System Service and General Plant groupings in the DSP. This Distribution System Plan that Northern Ontario Wires has prepared will guide future capital projects and spending. Funding for the 2025 portion of the DSP is included in the calculation of 2025TY revenue requirement, with projects assumed to be in service using the half-year rule.

Capital contributions are not significant in the operations of NOW Inc. As such, NOW Inc. has not forecast for any future capital contributions because they are not typical of historic patterns and future amounts are not determinable.

Efficiencies have arisen with the implementation of Go360 Live Ops Mapping, Asset Management Tools and ongoing Outage Management System reducing labor and truck roles for outages and better prioritizing maintenance. NOW Inc. is continuing with plans to generate more benefits from digitizing systems and modernizing operational practices.

The following **Table 1** provides capital expenditure information for the years 2017- 2029 and is summarized from OEB Appendix 2-AB which is provided in E2/T2/S1/Att2.

Table 1

Summary of Capital Expenditures

CATEGORY	Historic Period									Forecast Period				
	2017	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
	Plan	Actual	Actual	Actual	Actual	Actual	Actual	Actual	Bridge	Test	Forecast	Forecast	Forecast	Forecast
System Access	15	2	13	2	31	44	6	35	-	15	15	15	15	15
System Renewal	330	263	242	224	145	142	104	60	90	50	50	671	50	50
System Service	290	427	487	371	468	634	464	349	456	6,785	4,233	5,007	3,861	1,090
General Plant	143	153	140	77	193	39	373	282	1,327	64	706	64	64	646
Total Expenditure	**778**	**845**	**881**	**674**	**837**	**859**	**947**	**727**	**1,873**	**6,914**	**5,004**	**5,757**	**3,990**	**1,801**

Capital expenditure projects for the years 2017 – 2025 are provided in **Table 2** below. This information is based on OEB Appendix 2-AA (E2/T2/S1/Att3) and also includes 2017 OEB Approved capital expenditures.

Table 2

2017 – 2025 Capital Expenditures

Projects	2017 Approved	2017	2018	2019	2020	2021	2022	2023	2024 Bridge Year	2025 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
System Access										
Metering	15,000	1,770	12,829	1,796	30,699	43,959	6,033	35,040		15,000
System Access Gross Expenditures	15,000	1,770	12,829	1,796	30,699	43,959	6,033	35,040	0	15,000
System Access Capital Contributions										
Sub-Total	**15,000**	**1,770**	**12,829**	**1,796**	**30,699**	**43,959**	**6,033**	**35,040**	**0**	**15,000**
System Renewal										
Pole Changes- Cochrane	80,000	132,414	46,527	58,095	9,464	10,728	15,990	4,200		20,000
Pole Changes- Kapuskasing	55,000	1,487	16,038	3,144				2,803		20,000
Pole Changes-Iroquois Falls	55,000	743	1,590	20,653	5,042	16,330	8,218	33,654		10,000
Cochrane 5Kv Upgrade	90,000	82,726	89,815	129,474	130,079	103,945	79,434	19,484		
Substations	0	45,313	87,882	12,661		10,641			90,000	
System Renewal Gross Expenditures	280,000	262,683	241,852	224,027	144,585	141,644	103,642	60,141	90,000	50,000
System Renewal Capital Contributions		8,321								
Sub-Total	**280,000**	**254,362**	**241,852**	**224,027**	**144,585**	**141,644**	**103,642**	**60,141**	**90,000**	**50,000**
System Service										
Kapuskasing - 5Kv to 25Kv Conv. Upgrade	160,000	222,190	365,034	267,467	326,228	336,098	265,347	6,550	285,720	627,247
Iroquois Falls - 2.4 to 12 Kv Upgrade	130,000	204,484	121,507	93,164	68,968	5,273	17,090	53,993	170,000	
Cochrane Feeder Fortification										
Cochrane New Station	50,000			10,598	72,813	292,798	181,708	288,952		5,087,500
Iroquois Falls - 2.4 to 12 Kv Upgrade - Downtown										
Iroquois Falls - 2.4 to 12 Kv Upgrade - Millgate										1,070,677
System Service Gross Expenditures	340,000	426,674	486,541	371,229	468,009	634,169	464,145	349,495	455,720	6,785,424
System Service Capital Contributions										
Sub-Total	**340,000**	**426,674**	**486,541**	**371,229**	**468,009**	**634,169**	**464,145**	**349,495**	**455,720**	**6,785,424**
General Plant										
Transportation Equipment			85,492	135,435	60,387		213,425	118,513	410,754	
Computer Hardware	10,000			2,164			6,843	8,496	25,000	5,000
Computer Software	115,000	97,120	18,521		25,545		22,790	150,730	719,993	20,000
Buildings							21,623	4,270		30,000
Power Operated Tools									86,200	
Land									85,000	
Capital in Inventory (Spare Parts)		34,415	35,984	-60,708	107,505	39,037	80,429	-4,646		
General Plant Gross Expenditures	125,000	131,535	139,997	76,891	193,437	39,037	345,110	277,363	1,326,947	55,000
General Plant Capital Contributions										
Sub-Total	125,000	131,535	139,997	76,891	193,437	39,037	345,110	277,363	1,326,947	55,000
Miscellaneous	17,500	21,911					27,890	4,500		9,000
Total	**777,500**	**836,252**	**881,219**	**673,943**	**836,730**	**858,809**	**946,820**	**726,539**	**1,872,667**	**6,914,424**

Table 3 is derived from the information in Table 2 and provides the year over year changes in capital expenditures by project. Variances greater than $50,000 are highlighted and explanations are provided below.

Table 3

2017– 2025 Capital Expenditures Variances

Projects	2017 Actual vs 2017 Approved	2018 Actual vs 2017 Actual	2019 Actual vs 2018 Actual	2020 Actual vs 2019 Actual	2021 Actual vs 2020 Actual	2022 Actual vs 2021 Actual	2023 Actual vs 2022 Actual	2024 Bridge vs 2023 Actual	2025 Test vs 2024 Bridge
Reporting Basis	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**	**MIFRS**
System Access									
Metering	-13,230	11,059	-11,033	28,903	13,260	-37,926	29,007	-35,040	15,000
System Access Gross Expenditures	-13,230	11,059	-11,033	28,903	13,260	-37,926	29,007	-35,040	15,000
System Access Capital Contributions	0	0	0	0	0	0	0	0	0
Sub-Total	**-13,230**	**11,059**	**-11,033**	**28,903**	**13,260**	**-37,926**	**29,007**	**-35,040**	**15,000**
System Renewal									
Pole Changes- Cochrane	52,414	-85,887	11,568	-48,631	1,264	5,262	-11,790	-4,200	20,000
Pole Changes- Kapuskasing	-53,513	14,551	-12,894	-3,144	0	0	2,803	-2,803	20,000
Pole Changes-Iroquois Falls	-54,257	847	19,063	-15,611	11,288	-8,112	25,436	-33,654	10,000
Cochrane 5Kv Upgrade	-7,274	7,089	39,659	605	-26,134	-24,511	-59,950	-19,484	0
Substations	45,313	42,569	-75,221	-12,661	10,641	-10,641	0	90,000	-90,000
System Renewal Gross Expenditures	-17,317	-20,831	-17,825	-79,442	-2,941	-38,002	-43,501	29,859	-40,000
System Renewal Capital Contributions	8,321	-8,321	0	0	0	0	0	0	0
Sub-Total	**-25,638**	**-12,510**	**-17,825**	**-79,442**	**-2,941**	**-38,002**	**-43,501**	**29,859**	**-40,000**
System Service									
Kapuskasing - 5Kv to 25Kv Conv. Upgrade	62,190	142,844	-97,567	58,761	9,870	-70,751	-258,797	279,170	341,527
Iroquois Falls - 2.4 to 12 Kv Upgrade	74,484	-82,977	-28,343	-24,196	-63,695	11,817	36,903	116,007	-170,000
Cochrane Feeder Fortification	0	0	0	0	0	0	0	0	0
Cochrane New Station	-50,000	0	10,598	62,214	219,985	-111,090	107,245	-288,952	5,087,500
Iroquois Falls - 2.4 to 12 Kv Upgrade - Downtown	0	0	0	0	0	0	0	0	0
Iroquois Falls - 2.4 to 12 Kv Upgrade - Millgate	0	0	0	0	0	0	0	0	1,070,677
System Service Gross Expenditures	86,674	59,867	-115,312	96,779	166,160	-170,024	-114,650	106,225	6,329,704
System Service Capital Contributions	0	0	0	0	0	0	0	0	0
Sub-Total	**86,674**	**59,867**	**-115,312**	**96,779**	**166,160**	**-170,024**	**-114,650**	**106,225**	**6,329,704**
General Plant									
Transportation Equipment	0	85,492	49,943	-75,048	-60,387	213,425	-94,912	292,241	-410,754
Computer Hardware	-10,000	0	2,164	-2,164	0	6,843	1,653	16,504	-20,000
Computer Software	-17,880	-78,599	-18,521	25,545	-25,545	22,790	127,940	569,263	-699,993
Buildings	0	0	0	0	0	21,623	-17,353	-4,270	30,000
Power Operated Tools	0	0	0	0	0	0	0	86,200	-86,200
Land	0	0	0	0	0	0	0	85,000	-85,000
Capital in Inventory (Spare Parts)	34,415	1,569	-96,692	168,213	-68,468	41,392	-85,075	4,646	0
General Plant Gross Expenditures	6,535	8,462	-63,106	116,546	-154,400	306,073	-67,747	1,049,584	-1,271,947
General Plant Capital Contributions									
Sub-Total	6,535	8,462	-63,106	116,546	-154,400	306,073	-67,747	1,049,584	-1,271,947
Miscellaneous	4,411	-21,911	0	0	0	27,890	-23,390	-4,500	9,000
Total	**58,752**	**44,967**	**-207,276**	**162,786**	**22,079**	**88,011**	**-220,281**	**1,146,127**	**5,041,757**

2017 Actual over 2017 OEB Approved

- Pole Changes – Cochrane, $52,414 higher primarily due to more frequent line patrols that identified poles which required immediate attention.
- Pole Changes – Kapuskasing, $53,5137 lower primarily due to pole changes being included in the 25kV upgrade.
- Kapuskasing 5kV to 25kV Conversion, $62,190 higher primarily due the increase in priority of sections of the 25kV upgrade.

- Pole Changes – Iroquois Falls, $54,257 lower primarily due to pole changes being included in the 2.4kV to 12kV upgrade.
- Iroquois Falls - 2.4kV to 12kV Conversion, $74,484 higher primarily due the increase in priority of sections of the 12kV upgrade.
- Cochrane Station - Cochrane, $50,000, other priority emerged, and this was deferred

2018 Actual over 2017 Actual

- Pole Changes – Cochrane, $85,887 lower primarily due to pole replacements returning to the approved and anticipated level.
- Kapuskasing 5kV to 25kV Conversion, $142,844 higher primarily due the increase in priority of sections of the 25kV upgrade.
- Iroquois Falls - 2.4kV to 12kV Conversion, $82,977 lower primarily due the increase in priority of for the Kap 25 kV Conversion returns to approx. OEB approved levels.
- Transportation Equipment, $85,492 higher due to major capital repairs to vehicles on a derrick digger and an International bucket truck.
- Computer Software, $78,599 lower primarily due to 2017 major upgrades to billing system as well GIS work program.

2019 Actual over 2018 Actual

- Substations, $75,221 lower due to necessary work was completed and not recurring
- Kapuskasing 5kV to 25 kV Conversion, $97,567 lower primarily due to project pacing in relation to prior year
- Capital Inventory (Spare Parts), $96,692 lower due to spare parts inventory being charged to capital work orders.

2020 Actual over 2019 Actual

- Kapuskasing 5kV to 25kV Conversion, $58,761 higher primarily due to the increase in priority of sections of the 25kV upgrade and succeeded to do more.
- Cochrane New Station, $62,214 higher due to engineering services to study feasibility of new station and current station issues.
- Transportation Equipment, $75,048 lower primarily due to less addition to fleet.
- Capital Inventory (Spare Parts), $168,213 higher due to spare parts inventory replacing the major spares charged to work orders.

2021 Actual over 2022 Actual

- Iroquois Falls - 2.4kV to 12kV Conversion, $63,695 lower primarily due the increase in priority of sections of the 12kV upgrade.
- Cochrane New Station- $219,985 higher due to engineering services to study feasibility of the new station and current station issues.
- Transportation Equipment, $60,387 lower primarily due to no fleet additions incurred.
- Capital Inventory (Spare Parts)- $68,468 lower due to spare parts inventory being charged to capital work orders.

2022 Actual over 2021 Actual

- Kapuskasing 5kV to 25 kV Conversion, $70,751 lower primarily due to project pacing in relation to prior year and start of HR issues.
- Cochrane New Station, $111,090 lower due to completion of engineering feasibility study.
- Transportation Equipment, $213,425 higher primarily due to the purchase of a new 2x pickup truck to replace ones in disrepair.

2023 Actual over 2022 Actual

- Cochrane 5kV Upgrade, $59,950 lower primarily due to Transition in management personnel and HR issues
- Capital Inventory (Spare Parts), $85,075 lower due to spare parts inventory being charged to capital work orders.
- Kapuskasing 5kV to 25 kV Conversion, $258,797 lower primarily due to HR issues.
- Cochrane New Station, $107,245 higher due to engineering services to study feasibility of new station.
- Transportation Equipment, $94,912 lower primarily due to lower capital repairs
- Computer Software, 127,940 higher primary due to work on GIS system enhancements.

2024 Bridge Year over 2023 Actual

- Cochrane 5 kV Upgrade, $90,000 higher primarily due to project to add visibility into the existing MTS to be notified when a transformer goes down.
- Kapuskasing 5kV to 25kV Conversion, $279,170 higher primarily due priority shift for the Clark Street back yard issue and Matveev Avenue underground upgrade
- Iroquois Falls - 2.4kV to 12kV Conversion, $116,007 higher primarily due the HR issues resolved and new hires
- Cochrane New Station, $288,952 lower due completion of engineering studies.
- Transportation Equipment, $292,241 higher primarily due to the purchase of a new Altec Bucket Truck.
- Computer Software, $569,263 higher primarily due to asset management software and data implementation.
- Power Operated Tools, $86,200 higher primarily due to purchase of a hydro vac trailer and trencher

- Land, $85,000 higher primarily due to purchase of land for the New Cochrane MTS.

2025 Test Year over 2024 Bridge Year

- Cochrane 5 kV Upgrade, $90,000 lower primarily due to project to add visibility into the existing MTS to be notified when a transformer goes down completion.
- Kapuskasing 5kV to 25kV Conversion, $341,527 higher primarily due to conversion plans being contracted out.
- Cochrane New Station, $5,087,500 higher primarily due engineering work and transformer and equipment purchases for the new Cochrane MTS.
- Iroquois Falls 2.4kV to 12kV upgrade, $1,070,677 higher primarily due to conversion plans being contracted out.
- Transportation Equipment, $410,754 lower as no major equipment required replacement.
- Computer Software, $699,993 lower primarily due completion of asset management software and data implementation
- Power Operated Tools, $85,000 lower because equipment did not require replacement.
- Land, $85,000 lower due to purchase of land for the New Cochrane MTS completed in 2024.

Capital Planning

NOW Inc. participates in the municipal planning process in the towns of Kapuskasing, Iroquois Falls and Cochrane, it is also active with regional planning (such as Hydro One Networks Inc.) and other major stakeholders. Further information on Regional Planning can be found on in the DSP at E2/T2/S1/Att1, Appendix C.

In addition to the DSP, NOW Inc.'s capital plans are subject to annual O.Reg 22/04 Audit Report, the site inspection oil samples report, and the fleet matrix. The most recent versions of these reports are provided in E4/T4/S1/Att 6 & 7 and E2/T2/S1/Att4, respectively.

Table 4 provides a summary of Capital Expenditures for 2024 -2029.

Table 4

Summary of Capital Expenditures 2024 - 2029

	Forecast Period					
	2024	2025	2026	2027	2028	2029
	Bridge	Test	Forecast	Forecast	Forecast	Forecast
System Access	$ -	$ 15	$ 15	$ 15	$ 15	$ 15
System Renewal	$ 90	$ 5,138	$ 3,283	$ 4,451	$ 2,336	$ 50
System Service	$ 456	$ 1,698	$ 1,000	$ 1,227	$ 1,575	$ 1,090
General Plant	$ 1,327	$ 64	$ 706	$ 64	$ 64	$ 646
Total Expenditure	**$ 1,873**	**$ 6,914**	**$ 5,004**	**$ 5,757**	**$ 3,990**	**$ 1,801**

The key to effective capital planning is to prioritize the work as identified in NOW Inc.'s DSP. Capital work to the system benefits the consumer by ensuring that electricity is delivered in a reliable and safe manner.

Overall Capital Expenditure Strategy by Town

Cochrane: Northern Ontario Wires Inc. requires a new distribution station based on current loading issues. To rebuild the existing substation which is past its useful life is not desirable due to its proximity to the town's water supply. These issues are summarized in the Material Narrative (E2/T2/S1/Att1 Appendix A-1 & A-2). An Advanced Capital Module is requested for this project in E2/T2/S5.

BACKGROUND INFORMATION

Transformers T3 and T4 were installed in 1975. All 4.16 kV system transformers on site were installed prior to T3 and T4; their nameplates outline fabrication dates ranging from 1953 to 1960. There is an existing plan to eliminate the 115 kV to 4.16 kV transformers within the Cochrane distribution station; this load is to be transferred to the 25 kV system via 25 kV to 4.16 kV transformers. Please see below for a table of the load forecast information obtained from the feasibility study prepared by McMillan Distribution Engineering Consulting and Brian Smith This table clearly outlines that the peak load of the entire Town of Cochrane will exceed the redundant capacity of the 115/25 kV distribution transformers, meaning that a failure on either of the 115 kV to 25 kV during a peak period will cause an overload on the remaining transformer.

Table 5

Town of Cochrane Load Forecast

		Historical Data (kVA)					Near Term Forecast (kVA)					Medium Term Forecast (kVA)				
Season	Annual Growth %	2018*	2019	2020*	2021	2022	2023**	2024***	2025	2026	2027	2028	2029	2030	2031	2032
Summer	0%	11482	10466	11629	11411	10959	12129	12629	12629	12629	12629	12629	12629	12629	12620	12629
Summer	0.5%	11482	10521	11629	11411	10959	12190	12753	12817	12881	12945	13010	13075	13141	13206	13272
Summer	1.0%	11482	10521	11629	11411	10959	12250	12878	13007	13137	13268	13401	13535	13670	13807	13945
Winter	0%	13583	13107	12387	12493	12962	14083	14583	14934	14934	14934	14934	14934	14034	14934	14934
Winter	0.5%	13583	13107	12387	12493	12962	14153	14727	14800	14874	14949	15023	15099	15174	15250	15326
Winter	1%	13583	13107	12387	12493	12962	14224	14871	15020	15170	15322	15475	15630	15786	15944	16103

"Thermal Overload Protection of Power Transformers - Operating Theory and Practical Experience" by Rich Hunt, M.S., P.E. and Michael L. Giordano B.S., P.E. outline that operating above the rated temperature for short periods of time has a significant impact on the loss of life of an oil filled transformer. Below is a table outlining the various transformer loading states and the respective resulting life based on these temperatures. Determining exactly where within this table a transformer may operate depends on many variables such as ambient temperature, cooling methods, the thermal characteristics of the transformer and the amount of overload the transformer is exposed to. However, what is known is that peak loading conditions during the summer months correlate with extreme warm weather, which causes increased temperature of the transformer; as such, a single transformer failure during a peak summer event will result in accelerated aging of the remaining unit. As can be seen, the remaining life is reduced dramatically when operating outside of normal conditions. When the age of the T3 and T4 are considered, it becomes clear that a reduction of the remaining life is a risk to the Cochrane distribution system.

Table 6

Transformer Life Expectancy vs. Over-Temperature Operation

	[illegible]	[illegible] ameplate rating	[illegible]	[illegible]
Top-oil temperature	105° C	110° C	110° C	110° C
Hot-spot temperature	110° C	130° C	140° C	180° C
Loss-of-life factor	1.0000	6.9842	17.1994	424.9218
Resulting life	65,000 hours	9,307 hours	3,779 hours	153 hours

SAFETY CONCERNS

Entry to the 4.16 kV building within the Cochrane OS should be limited to when the system is de-energized due to the buswork mounted low within the building. This building is not a safe environment, and provisions must be made to remove it from service.

ENVIRONMENTAL CONCERNS

Being that the existing distribution system is located in close proximity to the Town's water supply, we believe that a relocation of the distribution station is necessary to prevent possible contamination from transformer oil.

NOW Inc. purchased land suitable for the new site in 2024 and is submitting an ACM for the station build as part of this Application. Additional work is required to reconfigure the existing feeders and add a new downtown feeder to accommodate the new site. A small distribution transformer will be strategically placed near the downtown core to power the existing 4.16 kV system to be converted in the future.

Figure 1

Cochrane

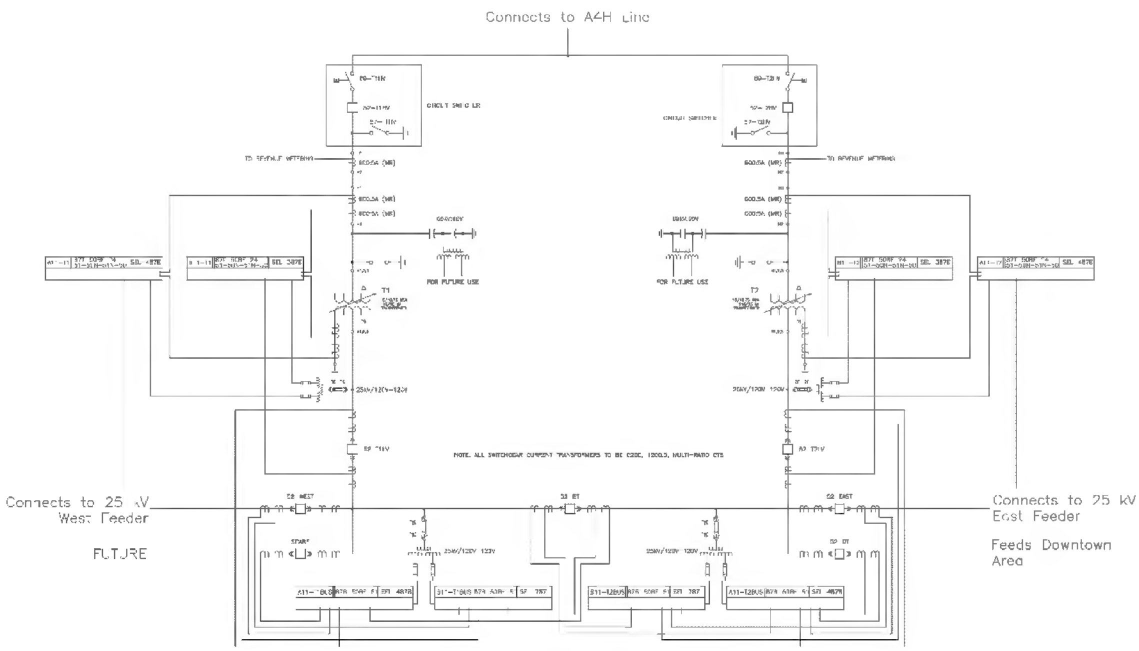


Figure 2

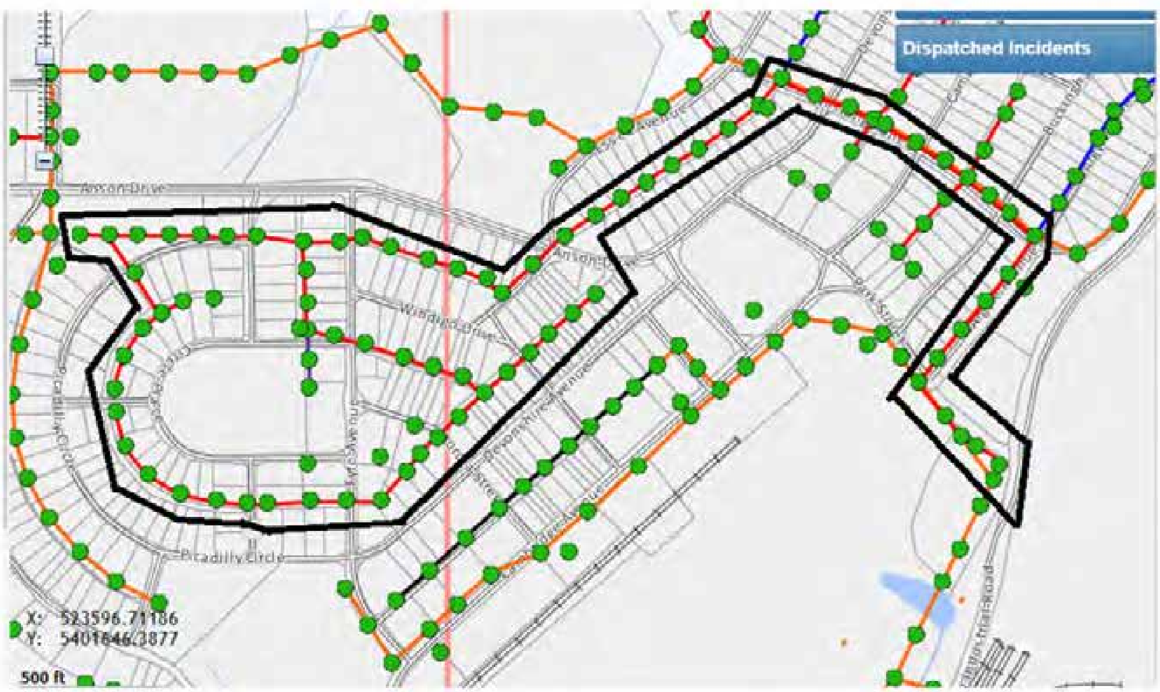
Cochrane

Iroquois Falls: The remainder of the Mill Gate 2.4 kV Delta system has been identified as a high-risk asset and must be decommissioned. Please see E2/T2/S1/A1 Appendix D-1 for test related details. The power factor significantly exceeds acceptable limits, and the secondary winding resistance exceeds acceptable limits. These are both signs of degradation in dielectric integrity of the paper insulation of this aged transformer.

This includes converting all exiting circuits fed from this substation to 12 kV and replacing new hardware poles and conductors. The final steps to complete this conversion are finalize an engineering design package and issue for construction tender to third party contractors. Construction is to be completed by the end of 2025.

Figure 3

Iroquois Falls Mill Gate Infrastructure

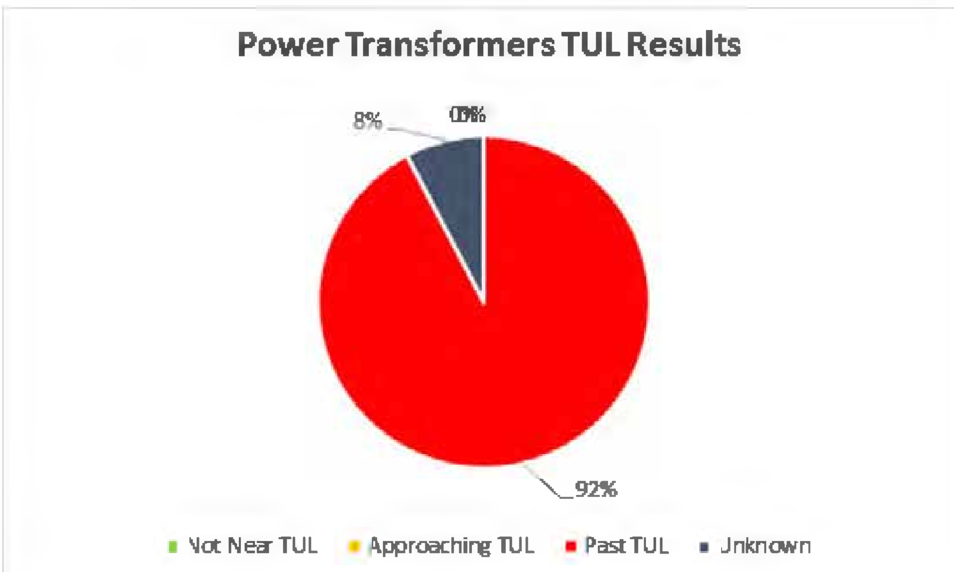


Iroquois Falls - 2.4 to 12 kV Upgrade – Downtown

The section of town if fed from a distribution transformer well passed its useful life expectancy (Detroyes 1966) it has been identified in the DSP E02/T02/S01 Appendix D – ACA that NOW Inc. Power Transformer fleet is 92% passed Typical Useful Life. For detailed information see D-1

Figure 4

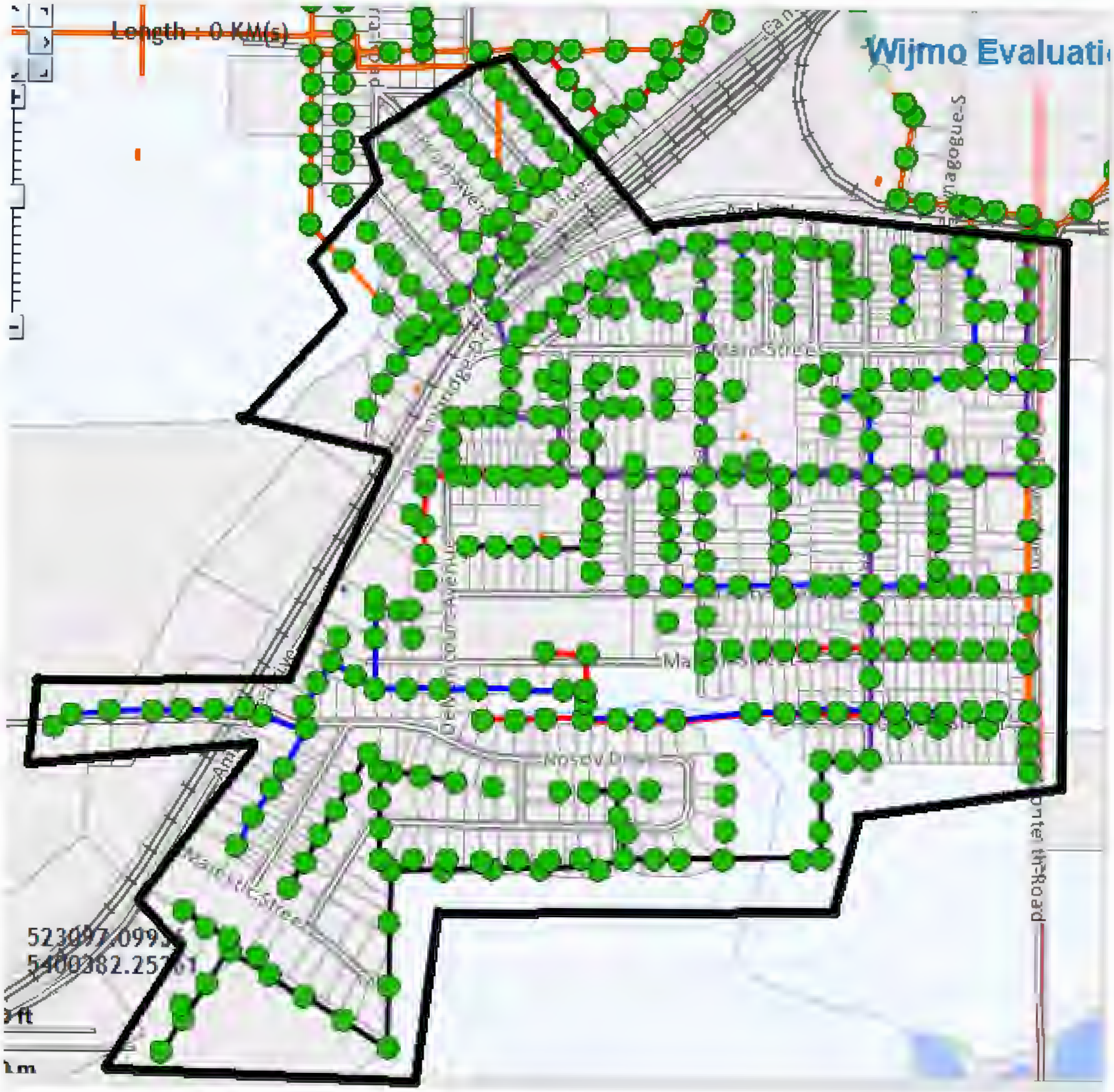
Power Transformers TUL Results



The DSP prioritized this project as per *Table 5.3-3: Prioritized list of projects/programs over the forecast period*. This project is estimated at $5,450,386 and will be completed as part of the next 2030-2034 DSP. This project will be separated into five sections and three of those sections will be put into service at the end of fiscal years 2027, 2028 and 2029. This is necessary to phase out the 1966 Detroyes transformer station which is well past its useful life. This conversion will eliminate a single point of failure and decrease line loss efficiency and the updated poles and hardware will increase system reliability and storm resiliency. Project design engineering will start in the fall of 2026 and construction packages will be issued for tender in the Spring of 2027.

Figure 5

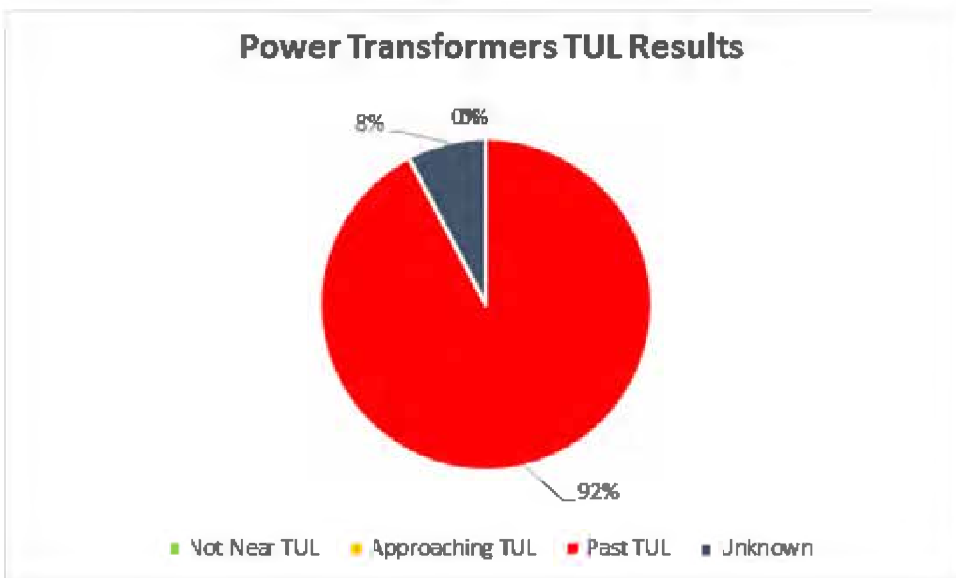
Iroquois Falls Downtown Core Infrastructure



Kapuskasing: The Mateev Substation (**1963**) transformer secondary winding resistance exceeds acceptable limits. This is a sing of degradation in dielectric integrity of the paper insulation of this aged transformer. Please see E2/T2/S1/A1 Appendix D-2 for test related details The substation switch gear is also passed its TUL and the equipment is no longer supported by the manufacturer (CLM Industries) is no longer in business rendering parts unavailable. NOW Inc Power Transformer fleet is 92% passed Typical Useful Life.

Figure 6

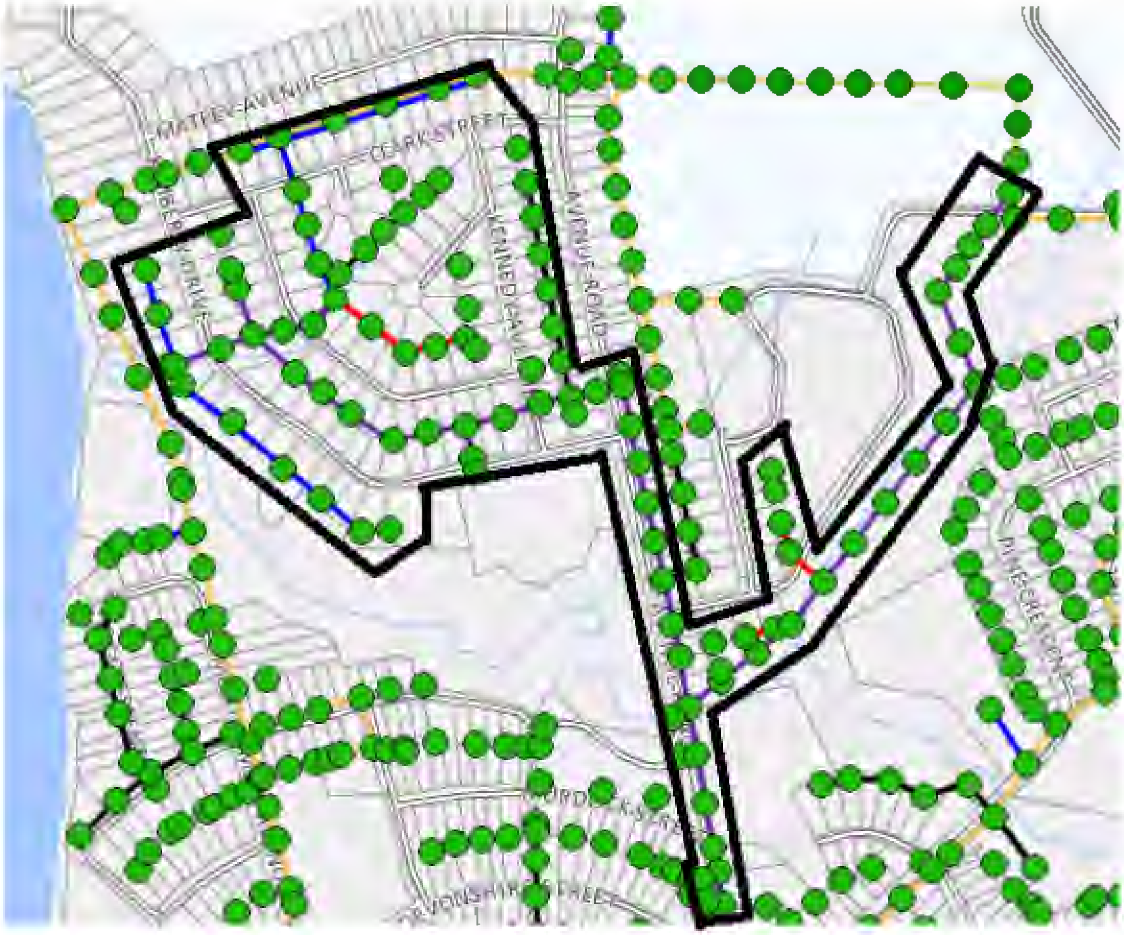
Power Transformers TUL Results



The DSP prioritized this project as per *Table 5.3-3: Prioritized list of projects/programs over the forecast period*. In order to mitigate line losses and improve reliability, an ongoing decommissioning project is underway in Kapuskasing (*Figure 6)*. The decommissioning of the Mateev Substation B and subsequent upgrade from 5kV to 25kV is expected to end in 2026. This station was identified in NOW Inc.'s previous Asset Management Program as exceeding Typical Useful Life. Additionally, poles which require upgrades as identified in the Distribution System Plan (DSP) have been identified. These improvements are expected to reduce future maintenance costs and increase service reliability.

Figure 7

Kapuskasing River Heights Infrastructure



Description by Project

Table 7

2024 Capital Projects

2024 CAPITAL PROJECTS		
System Renewal	$	90,000
General Plant	$	1,326,946
System Access	$	-
System Service	$	455,720
2024 Actual Capital Projects	**$**	**1,872,667**

System Renewal:

Project 2024: Substations (MTS Visibility) – Total Cost $ 90,000

- Visibility into the old Cochrane MTS is necessary to mitigate risk if a transformer is out of service. This will be accomplished with the implementation of an SEL RTAC capable of sending an email notification allowing NOW Inc. to react and shed load during a peak condition.

System Service:

Project 2024: Kapuskasing 5kV to 25kV Conversion Upgrade – Total Cost $ 285,720

- This project encompasses the decommissioning of the Mateev Substation B and subsequent upgrade from 5kV to 25kV as identified in the introduction. Given the size of this project and dependent on the short construction season, NOW Inc. is anticipating completion in 2026. This station was identified in NOW Inc.'s previous Asset Management Program as approaching and exceeding end of life. As part of the conversion, poles, and transformers are also being replaced which reduces the age of the infrastructure and extends the life of the distribution system. Decommissioning the Mateev Substation B will reduce future operation and maintenance costs along with liability. By eliminating the substation, NOW Inc. will feed off of Hydro One directly. Additionally, conversion will reduce line loss and improve reliability and safety of the distribution system.

Project 2024: Iroquois Falls 2.4 to 12 kV Upgrade – Total Cost $ 170,000

- An ongoing conversion/upgrade project, this consists of removing the 2.4kV Delta station from service in order to improve efficiencies such as reducing line loss and improving system reliability. In conjunction with the decommissioning of the 2.4kV Delta station, upgrades to the 12kV system are being implemented. The anticipated end date of the Delta station upgrade project is 2025. When the 2.4kV Delta station is removed, an aged asset will be eliminated which decreases risk associated with failure being both cost and environmental impacts. After eliminating the station, the service territory will be fed by a Hydro One station. This will reduce costs associated with maintenance and repairs for NOW Inc.

General Plant:

Transportation Equipment 2024 – Total Cost $410,754

Due to geography, NOW Inc. has multiple vehicles that perform similar functions. The communities that NOW Inc. services are 170 kilometers apart with only one main road between towns. Accordingly, it is necessary to have vehicles available in both Kapuskasing and Cochrane/Iroquois Falls areas as road closures are common in the winter months. This capital expenditure helps to reduce outage duration and response time in all communities, which has a benefit to customers with respect to reliability. To keep the fleet up to date NOW Inc. has purchased a new small Altec Model AT48M Articulating Telescopic Aerial Device.

2024 Power Operated Tools – Total Cost $ 86,250

NOW Inc. has purchased a Hydro Vac trailer and a trencher to better serve customers with underground services. This equipment will decrease customer underground secondary service interruptions by having access to excavation equipment needed to safely repair aging underground services more prone to sort circuits and ground faults.

2024 Computer Software – Total Cost $ 719,993

- In 2024 NOW Inc. is focused on digitising its management systems. The Go360 platform offers numerous applications including reporting tools, asset management tools, service order systems, outage management maps (available to the pubic) this project includes data gathering of all assets, GIS mapping initiatives and asset assessments. This will create efficiencies with troubleshooting outages and response time, asset maintenance prioritizing and assist with record keeping for regulatory purposes.

2024 Land – Total Cost $ 85,000

- NOW Inc. has purchased land from the town of Cochrane on Western Ave for the new Cochrane MTS. This land was strategically purchased because of its proximity to the A4H Hydro One transmission line. The A4H easement passes through the property creating major efficiencies reducing the need for costly transmission line construction.

Table 8

2025 Capital Projects

2025	
System Access	15,000
System Renewal	50,000
System Service	6,785,424
General Plant	64,000
Total	6,914,424

System Access:

2025 Metering – Total Cost $ 15,000

- On an annual basis, a number of smart meters require replacement, either due to age or defectiveness. Northern Ontario Wires Inc. has included such meter replacements within its capital budget. This amount includes the replacement cost, and the labour and material associated with replacement. Having a working meter is essential to the customer in order to record electricity usage and ensure accurate invoicing.

System Renewal:

Project 2025: Cochrane Pole Changes – Total Cost $ 20,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2025: Kapuskasing Pole Changes – Total Cost $ 20,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore, conductor attachments are higher, reducing the risk of foreign interference.

<u>Project 2025: Iroquois Falls Pole Changes – Total Cost $ 10,000</u>

As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore, conductor attachments are higher, reducing the risk of foreign interference

System Service:

<u>Project 2025: New Cochrane MTS – Total Cost $ 5,087,500</u>

- **Year one of the New Cochrane MTS** will focus on formal design, creating construction tender packages, yard surfacing, and initial groundwork. The approval process with the IESO will also commence, which includes obtaining Hydro One CIA, and IESO SIA approvals. Long lead-time purchasing will start to ensure delivery aligns with anticipated approvals. Key items include, but are not limited to, two 15/18.75 MVA transformers with tap changers, surge arresters, and mechanical protection accessories.

<u>Project 2025: Iroquois Falls - 2.4 to 12 kV Upgrade - Millgate – Total Cost $ 1,070,677</u>

Mill Gate 2kV to 12kV

The mill gate project consists of replacing the remainder of the existing antiquated 2kV Delta system which dates back to 1955. This will eliminate the need for the Substation that has tested poorly. For example the power factor of this transformer is below IEEE acceptable limits. This will reduce line inefficiencies, reduce maintenance cost and eliminate a single point of failure.

The conversion will be to the modern standard for Iroquois Falls at 12kV. The asset count to be replaced is identified below.

Table 9

Mill Gate System Summary	
Asset	**Count**
Poles	86
Transformers	21
Switches	3
Cable Length (primary)	2,569.794 m
Cable Length (secondary)	4,748.879 m

NOW Inc. has identified the need for outside resources for project of this magnitude and has priced the project to be contracted to a third party. Conceptual design is underway, and the formal design will be completed during the winter month of 2024/2025 and ready for construction tender early spring. All material for this project will be purchased to ensure a construction start of May 2025. The total manhours not including supervision for this project will be 1,416 hours and is broken down below.

Table 10

Mill Gate Manhours

Pole Hardware Installation	2x Journeyman Powerline Tech 2 hours per pole
Pole Erection	2x Journeyman Powerline Tech 2 hours per pole
Primary line String	4x Journeyman Powerline Tech 2 hours per Span
Secondary line String	4x Journeyman Powerline Tech 2 hours per Span
Guy Wire Installation	2x Journeyman Powerline Tech 2 hours per pole
Grounding	2x Journeyman Powerline Tech 1 hours per pole
Transformer Installation	2x Journeyman Powerline Tech 3 hours per Transformer

Equipment cost is based on a 20-day construction period working at 10 hours a day.

Table 11

Mill Gate Equipment

Trailer, Pole, or Cable	2 Cable Trailer per day
Crew cab Pickup Truck – 4 x 4	2 trucks for 4 crews per hour
Bucket Truck – 50 ft to 55 ft	2 trucks for 4 crews per hour
Line Truck, Flat deck c/w RBD	2 trucks for 4 crews per hour

Project 2026: Kapuskasing - Kap River Heights 5kV to 25kV – Total Cost $ 627,247

Kap River Heights 5kV to 25kV

The Kap River Heights 5kV to 25kV project consists of replacing the remainder of the existing antiquated 5kV system dating back to 1963. This will eliminate the need for the Substation and begin addressing the unique Kapuskasing backyard easement issues, will increase line inefficiencies, reduce maintenance cost and eliminate a single point of failure.
In year 2025 we will be tackling approximately one third of the overall project. The conversion will be to the modern standard for Kapuskasing at 25kV. The asset count to be replaced is identified below. The remainder of the project will be completed in 2026.

Table 12

Kapuskasing 25 kV Asset Count

System Summary	
Asset	**Count**
Poles	108
Transformers	19
Switches	6
Cable Length (Primary 3PH)	6,458.094 m
Cable Length (Primary 1PH)	1,508.249 m
Cable Length (Secondary)	3,698.127

NOW Inc. has identified the need for outside resources for project of this magnitude and has priced the project to be contracted to a third party. Conceptual design is underway, and the formal design will be completed in the spring of 2025 and ready for construction tender early summer. All material for this project will be purchased to ensure a construction start of July 2025. The total manhours not including supervision for this project will be 2,924 hours and is broken down below.

Table 13

Kap River Heights Manhours

Pole Hardware Installation	2x Journeyman Powerline Tech 2 hours per pole
Pole Erection	2x Journeyman Powerline Tech 2 hours per pole
Primary line String	4x Journeyman Powerline Tech 2 hours per span
Secondary line String	4x Journeyman Powerline Tech 2 hours per span
Guy Wire Installation	2x Journeyman Powerline Tech 2 hours per pole
Grounding	2x Journeyman Powerline Tech 1 hours per pole
Transformer Installation	2x Journeyman Powerline Tech 3 hours per Transformer

Equipment cost is based on a 36-day construction period working at 10 hours a day

Table 14

Kap River Heights Equipment

Trailer, Pole, or Cable	2 Cable Trailer per day
Crew cab Pickup Truck – 4 x 4	2 trucks for 4 crews per hour

Bucket Truck – 50 ft to 55 ft	2 trucks for 4 crews per hour
Line Truck, Flat deck c/w RBD	2 trucks for 4 crews per hour

General Plant

2025 Computer Software – Total Cost $ 20,000

To remain abreast of technological advances, NOW Inc. plans for cyclical updates to computer software of computers on an annual basis. These primary tools of communication are necessary to process reports, complete service orders and for communication purposes among the outside workers and all billing aspects of NOW's operation.

2025 Buildings – Total Cost $ 30,000

NOW Inc. serves three communities. This capital expenditure is for anticipated minor building improvements in each community.

Table 15
2026 Capital Expenditures

2026	
System Access	15,000
System Renewal	50,000
System Service	4,233,324
General Plant	705,717
Total	5,004,041

System Access:

2026 Metering – Total Cost $ 15,000

- On an annual basis, a number of smart meters require replacement, either due to age or defectiveness. As such, Northern Ontario Wires Inc. has included meter replacements within its capital project. This amount includes the replacement cost, and the labour and material associated with such replacement. Having a working meter is essential to the customer in order to record usage and ensure accurate invoicing.

System Renewal:

Project 2026: Cochrane Pole Changes – Total Cost $ 20,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified for replacement, either due to age or condition. The replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, planned pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2026: Kapuskasing Pole Changes – Total Cost $ 20,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified for replacement, either due to age or condition. The replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore, conductor attachments are higher, reducing the risk of foreign interference.

Project 2026: Iroquois Falls Pole Changes – Total Cost $ 10,000

As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified for replacement, either due to age or condition. The replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore, conductor attachments are higher, reducing the risk of foreign interference

System Service:

Project 2026: New Cochrane MTS – Total Cost $ 3,233,324

Year two of the New Cochrane MTS will concentrate on purchasing critical equipment such as HV circuit switchers with grounding switches, HV CVTs for the 115 kV system, double secondary HV CTs for the 115 kV system, and protection-grade and metering-grade CTs. Both prefab switch e-houses and control e-houses will be ordered according to the design specifications. Preliminary construction will begin on the concrete foundations and ground grid.

Project 2026: Kap River Heights 5kVto 25 kV –Total Cost $ 1,000,000

Kap River Heights 5kV to 25kV

The Kap River Heights 5kV to 25kV project consists of replacing the remainder of the existing antiquated 5kV system dating back to 1963. This will eliminate the need for the Substation and begin addressing the unique Kapuskasing backyard easement issues This will reduce line inefficiencies, reduce maintenance cost and eliminate a single point of failure.

The conversion will be to the modern standard for Kapuskasing at 25kV. The asset count to be replaced is identified below.

Table 16

Kapuskasing 25 kV Asset Count

System Summary	
Asset	**Count**
Poles	108
Transformers	19
Switches	6
Cable Length (Primary 3PH)	6,458.094 m
Cable Length (Primary 1PH)	1,508.249 m
Cable Length (Secondary)	3,698.127

NOW Inc. has identified the need for outside resources for project of this magnitude and has priced the project to be contracted to a third party. Conceptual design is underway, and the formal design will be completed in the spring of 2025 and ready for construction tender early summer. All material for this project will be purchased to ensure a construction start of July 2025. The total manhours not including supervision for this project will be 2,924 hours and broken down below a portion of this construction will

Table 17

Kap River Heights Manhours

Pole Hardware Installation	2x Journeyman Powerline Tech 2 hours per pole
Pole Erection	2x Journeyman Powerline Tech 2 hours per pole
Primary line String	4x Journeyman Powerline Tech 2 hours per Span
Secondary line String	4x Journeyman Powerline Tech 2 hours per Span
Guy Wire Installation	2x Journeyman Powerline Tech 2 hours per pole
Grounding	2x Journeyman Powerline Tech 1 hours per pole
Transformer Installation	2x Journeyman Powerline Tech 3 hours per Transformer

Equipment cost is based on a 36-day construction period working at 10 hours a day.

Table 18

Kap River Equipment

Trailer, Pole, or Cable	2 Cable Trailer per day
Crew Cab Pickup Truck – 4 x 4	2 trucks for 4 crews per hour
Bucket Truck – 50 ft to 55 ft	2 trucks for 4 crews per hour
Line Truck, Flat deck c/w RBD	2 trucks for 4 crews per hour

General Plant:

Transportation Equipment 2026 – Total Cost $641,717

Due to geography, NOW Inc. requires vehicles that perform similar functions at different locations. The communities serviced are 170 kilometers apart with only one main road between towns, it is necessary to have availability as road closures are common in the winter months. This helps to reduce response time and outage in all communities, which has a reliability benefit to our customers. To keep the fleet up to date NOW Inc. plans on purchasing a new POSI-PLUS MODEL 500-55/65 Articulating Telescopic Aerial Device.

2026 Computer Software – Total Cost $ 20,000

In order to current with technological advances, NOW Inc. plans for cyclical updates to computer software of computers on an annual basis. These primary tools of communication are necessary in order to process reports, complete service orders and for communication purposes among the outside workers and all billing aspects of NOW Inc.'s operation.

2026 Buildings – Total Cost $ 30,000

NOW Inc. serves three communities. This capital expenditure is for anticipated minor building improvements in each community.

2027 CAPITAL PROJECTS

Table 19
2027 Capital Projects

2027	
System Access	15,000
System Renewal	671,000
System Service	5,006,944
General Plant	64,000
Total	5,756,944

System Access:

2027 Metering – Total Cost $ 15,000

- On an annual basis, a number of smart meters require replacement, either due to age or defectiveness. As such, Northern Ontario Wires Inc. has included meter replacements within its capital project. This amount includes the replacement cost, and the labour and material associated with such replacement. Having a working meter is essential to the customer in order to record usage and ensure accurate invoicing.

System Renewal:

Project 2027: Cochrane Pole Changes – Total Cost $ 20,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified for replacement, either due to age or condition. The replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, planned pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2027: Kapuskasing Pole Changes – Total Cost $ 20,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified for replacement, either due to age or condition. The replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore, conductor attachments are higher, reducing the risk of foreign interference.

Project 2027: Iroquois Falls Pole Changes – Total Cost $ 10,000

As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified for replacement, either due to age or condition. The replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, pole replacements may change location as a result. Furthermore, new poles are longer; therefore, conductor attachments are higher, reducing the risk of foreign interference

Project 2027: Cochrane 5kV Upgrade – Total Cost $671,000

This portion of the project involves connecting a new dedicated Downtown Feeder to the new Cochrane MTS. The work includes trenching from the new medium voltage switchgear to riser poles, extending beyond the limits of the fenced area. An overhead section of the line will be installed, spanning from the edge of Western Ave to the final directional bore conduit drilling section. Conductors along 5th St up to the train tracks will be replaced with 3/0 ACSR. A small distribution transformer will be installed to power the remainder of the downtown core, allowing for the decommissioning of the existing 5 kV substation and future conversion of the downtown core to 25 kV. Additionally, a tie point will be established in the future between the East and Downtown Feeders and the West Feeder to the Downtown Feeder to enhance grid reliability once the future 5 kV Downtown core conversion is completed.

System Service:

Project 2027: New Cochrane MTS – Total Cost $3,779,882

Year three of the New Cochrane MTS will focus on construction activities related to the HV system, including HV CTs, transformers, and structures. This phase includes cable tray construction, cabling runs and terminations, switchgear building wiring, control building wiring, P&C construction, and battery system and panel wiring.

Project 2027: Iroquois Falls - 2.4 to 12 kV Upgrade – Total Cost $1,227,062

The Iroquois Falls Downtown core project consists of replacing the remainder of the existing antiquated 5kV system which dates back to 1966. This will eliminate the need for the Substation that is past its useful life expectancy. The unit has an oil submersed primary switch made of oak with obsolete entry point (pot heads). If this fails parts are no longer available. This will increase line inefficiencies, reduce maintenance cost. And eliminate a single point of failure.

The conversion will be to the modern standard for Iroquois Falls at 12kV. The asset count to be replaced is identified below. during design stage NOW Inc will divide this 5-million-dollar project into five sections and execute over the course of five years.

Table 20

Downtown IF Summary	
Asset	**Count**
Poles	353
Transformers	77
Switches	14
Cable Length (3PH)	9,565.161 m
Cable Length (1PH)	9,384.84 m
Cable Length (Secondary)	20,985.647 m

NOW Inc. has identified the need for outside resources for project of this magnitude and has priced the project to be contracted to a third party. Formal design will be completed during the winter month of 2026/2027 and ready for construction tender early spring. All material for this project will be purchased to ensure a construction start of May 2027. The total manhours not including supervision for this project will be approximately 1/5 of 9,390 hours and broken down below:

Table 21

Iroquois Falls Upgrade Manhours

Pole Hardware Installation	2x Journeyman Powerline Tech 2 hours per pole
Pole Erection	2x Journeyman Powerline Tech 2 hours per pole
Primary line String	4x Journeyman Powerline Tech 2 hours per Span
Secondary line String	4x Journeyman Powerline Tech 2 hours per Span
Guy Wire Installation	2x Journeyman Powerline Tech 2 hours per pole
Grounding	2x Journeyman Powerline Tech 1 hours per pole
Transformer Installation	2x Journeyman Powerline Tech 3 hours per Transformer

Equipment cost is based on a 118-day construction period working at 10 hours a day.

Table 22

Iroquois Falls Upgrade Equipment

Trailer, Pole, or Cable	2 Cable Trailer per day
Crew cab Pickup Truck – 4 x 4	2 trucks for 4 crews per hour
Bucket Truck – 50 ft to 55 ft	2 trucks for 4 crews per hour
Line Truck, Flat deck c/w RBD	2 trucks for 4 crews per hour

General Plant:

2027 Computer Software – Total Cost $ 20,000

In order to keep current with technological advances, NOW Inc. plans for cyclical updates to computer software of computers on an annual basis. These primary tools of communication are necessary in order to process reports, complete service orders and for communication purposes among the outside workers and all billing aspects of NOW Inc.’s operations.

2027 Buildings – Total Cost $ 30,000

NOW Inc. serves three communities. This capital expenditure is for anticipated minor building improvements in each community.

2028 CAPITAL PROJECTS

Table 23

2028 Capital Projects

2028	
System Access	15,000
System Renewal	50,000
System Service	3,860,909
General Plant	64,000
Total	3,989,909

System Access:

2028 Metering – Total Cost $ 15,000

- On an annual basis, a certain number of smart meters require replacement, either due to age or defectiveness. As such, Northern Ontario Wires Inc. has included meter replacements within its capital project. This amount includes the replacement cost, and the labour and material associated with such replacement. Having a working meter is essential to the customer in order to record usage and ensure accurate invoicing.

System Renewal:

Project 2028: Cochrane Pole Changes – Total Cost $ 20,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified for replacement, either due to age or condition. The replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, planned pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2028: Kapuskasing Pole Changes – Total Cost $ 20,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. The replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, planned pole replacements may change location as a result. Furthermore, new poles are longer; therefore, conductor attachments are higher, reducing the risk of foreign interference.

Project 2028: Iroquois Falls Pole Changes – Total Cost $ 10,000

As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified, either due to age or condition, for replacement. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, planned pole replacements may change location as a result. Furthermore, new poles are longer; therefore, conductor attachments are higher, reducing the risk of foreign interference

System Service:

Project 2028: New Cochrane MTS – Total Cost $2,285,832

Year four of the New Cochrane MTS will be focused but not limited to finalizing all 2027 construction activities and system testing and commissioning. Once all parties are satisfied with the test results (IESO and Hydro One) the connection process with the A4H will commence. Once connected to the A4H. Commissioning and testing to connect first the East feeder first, following the West feeder. This will all align with the Cochrane system fortification project.

Project 2028: Iroquois Falls - 2.4 to 12 kV Upgrade Downtown – Total Cost $1,090,077

The Iroquois Falls Downtown core project consists of replacing the remainder of the existing antiquated 5kV system which dates back to 1966. This will eliminate the need for the Substation that is past it useful life expectancy. The unit has an oil submersed primary switch made of oak with obsolete entry point (pot heads). If this fails parts are no longer available. This will reduce line inefficiencies, reduce maintenance cost and eliminate a single point of failure.

The conversion will be to the modern standard for Iroquois Falls at 12kV. the asset count to be replaced is identified below. during design stage NOW Inc will divide this 5-million-dollar project into five sections and execute construction over the course of five years.

Table 24

Downtown IF Summary	
Asset	**Count**
Poles	353
Transformers	77
Switches	14
Cable Length (3PH)	9565.161 m
Cable Length (1PH)	9384.84 m
Cable Length (Secondary)	20985.647 m

NOW Inc. has identified the need for outside resources for project of this magnitude and has priced the project to be contracted to a third party. Formal design will be completed during the winter month of 2027/2028 and ready for construction tender early spring. All material for this project will be purchased to ensure a construction start of May 2028. The total manhours not including supervision for this project will be approximately 1/5 of 9,390 hours and broken down below.

Table 25

Iroquois Falls Upgrade Manhours

Pole Hardware Installation	2x Journeyman Powerline Tech 2 hours per pole
Pole Erection	2x Journeyman Powerline Tech 2 hours per pole
Primary line String	4x Journeyman Powerline Tech 2 hours per Span
Secondary line String	4x Journeyman Powerline Tech 2 hours per Span
Guy Wire Installation	2x Journeyman Powerline Tech 2 hours per pole
Grounding	2x Journeyman Powerline Tech 1 hours per pole
Transformer Installation	2x Journeyman Powerline Tech 3 hours per Transformer

Equipment cost is based on a 118-day construction period working at 10 hours a day

Table 26

Iroquois Falls Upgrade Equipment

Trailer, Pole, or Cable	2 Cable Trailer per day
Crew cab Pickup Truck – 4 x 4	2 trucks for 4 crews per hour
Bucket Truck – 50 ft to 55 ft	2 trucks for 4 crews per hour
Line Truck, Flat deck c/w RBD	2 trucks for 4 crews per hour

General Plant:

2028 Computer Software – Total Cost $ 20,000

In order to remain abreast of technological advances, NOW Inc. plans for cyclical updates to computer software of computers on an annual basis. These primary tools of communication are necessary in order to process reports, complete service orders and for communication purposes among the outside workers and all billing aspects of NOW Inc.'s operation.

2028 Buildings – Total Cost $ 30,000

NOW Inc. serves three communities. This capital expenditure is for anticipated minor building improvements in each community.

2029 CAPITAL PROJECTS

Table 27

2029 Capital Projects

2029	
System Access	15,000
System Renewal	50,000
System Service	1,090,077
General Plant	646,315
Total	1,801,392

System Access:

2029 Metering – Total Cost $ 15,000

- On an annual basis, a certain number of smart meters require replacement, either due to age or defectiveness. As such, Northern Ontario Wires Inc. has included meter replacements within its capital project. This amount includes the replacement cost, and the labour and material associated with such replacement. Having a working meter is essential to the customer in order to record usage and ensure accurate invoicing.

System Renewal:

Project 2029: Cochrane Pole Changes – Total Cost $ 20,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified for replacement, either due to age or condition. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, planned pole replacements may change location as a result. Furthermore, new poles are longer; therefore conductor attachments are higher, reducing the risk of foreign interference.

Project 2029: Kapuskasing Pole Changes – Total Cost $ 20,000

- As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified for replacement, either due to age or condition. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, planned pole replacements may change location as a result. Furthermore, new poles are longer; therefore, conductor attachments are higher, reducing the risk of foreign interference.

Project 2029: Iroquois Falls Pole Changes – Total Cost $ 10,000

As discussed in NOW Inc.'s Distribution System Plan (DSP), some poles have been identified for replacement, either due to age or condition. This replacement plan assists with overhead maintenance and improves safety and reliability of equipment. Occasionally, due to accident or visual observation, planned pole replacements may change location as a result. Furthermore, new poles are longer; therefore, conductor attachments are higher, reducing the risk of foreign interference

System Service:

Project 2028: Iroquois Falls - 2.4 to 12 kV Upgrade Downtown – Total Cost $1,090,077

The Iroquois Falls Downtown core project consists of replacing the remainder of the existing antiquated 5kV system which dates back to 1966. This will eliminate the need for the Substation that is passed it useful life expectancy. The unit has an oil submersed primary switch made of oak with obsolete entry point (pot heads). If this fails parts are no longer available. This will reduce line inefficiencies, reduce maintenance cost. And eliminate a single point of failure.

The conversion will be to the modern standard for Iroquois Falls at 12kV. The asset count to be replaced is identified below. during design stage NOW Inc will divide this 5-million-dollar project into five sections and execute construction over the course of five years.

Table 28

Downtown IF Summary	
Asset	**Count**
Poles	353
Transformers	77
Switches	14
Cable Length (3PH)	9,565.161 m
Cable Length (1PH)	9,384.84 m
Cable Length (Secondary)	20,985.647 m

NOW Inc. has identified the need for outside resources for project of this magnitude and has priced the project to be contracted to a third party. Formal design will be completed during the winter month of 2028/2029 and ready for construction tender early spring. All material for this project will be purchased to ensure a construction start of May 2029. The total manhours not including supervision for this project will be approximately 1/5 of 9,390 hours and broken down below:

Table 29

Iroquois Falls Upgrade Manhours

Pole Hardware Installation	2x Journeyman Powerline Tech 2 hours per pole
Pole Erection	2x Journeyman Powerline Tech 2 hours per pole
Primary line String	4x Journeyman Powerline Tech 2 hours per Span
Secondary line String	4x Journeyman Powerline Tech 2 hours per Span
Guy Wire Installation	2x Journeyman Powerline Tech 2 hours per pole
Grounding	2x Journeyman Powerline Tech 1 hours per pole
Transformer Installation	2x Journeyman Powerline Tech 3 hours per Transformer

Equipment cost is based on a 118-day construction period working at 10 hours a day.

Table 30

Iroquois Falls Upgrade Equipment

Trailer, Pole, or Cable	2 Cable Trailer per day
Crew cab Pickup Truck – 4 x 4	2 trucks for 4 crews per hour
Bucket Truck – 50 ft to 55 ft	2 trucks for 4 crews per hour
Line Truck, Flat deck c/w RBD	2 trucks for 4 crews per hour

General Plant:

<u>Transportation Equipment 2029 – Total Cost $582,315</u>

Due to geography, NOW Inc. has multiple vehicles that perform similar functions. The communities serviced are 170 kilometers apart with only one main road between towns. It is necessary to have redundancies as road closures are common in the winter months. Expenditures on transportation equipment help to replace aging fleet and ensure appropriate outage and response time in all communities. To keep the fleet up to date NOW Inc. plans on purchasing a new a POSI-PLUS MODEL 900-55 Digger Derrick.

<u>2029 Computer Software – Total Cost $ 20,000</u>

In order to keep current with technological advances, NOW Inc. plans for cyclical updates to computer software of computers on an annual basis. These primary tools of communication are necessary in order to process reports, complete service orders and for communication purposes among the outside workers and all billing aspects of NOW Inc.'s operation.

<u>2029 Buildings – Total Cost $ 30,000</u>

NOW Inc. serves three communities. This capital expenditure is for anticipated minor building improvements in each community.

Attachment 1 (of 4):

Distribution System Plan

Northern Ontario Wires Inc.

Distribution System Plan

2025 Cost of Service Application

Historical Period:

2017-2023 (2024 Bridge Year)

Forecast Period:

2025 – 2029

August 30, 2024

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List of Acronyms

Acronym	Meaning
ACA	Asset Condition Assessment
AM	Asset Management
CDM	Conservation Demand Management
CHI	Customer Hours Interrupted
CI	Customers Interrupted
DER	Distributed Energy Resources
DS	Distribution Substation
DSC	Distribution System Code
DSP	Distribution System Plan
EDA	Electricity Distributors Association
ESA	Electrical Safety Authority
GIS	Geographic information system
GS	General Service
HI	Health Index
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
IT	Information Technology
kW	Kilowatts
LDC	Local Distribution Company
LIP	Local Initiatives Program
LOS	Loss of Supply
MED	Major Event Detail
MTS	Municipal Transformer Station
NOW Inc.	Northern Ontario Wires Inc.
O&M	Operation and Maintenance
OEB	Ontario Energy Board
OH	Overhead
OMS	Outage Management System
OT	Operational Technology
PF	Power Factor
RAS	Remedial Action Scheme
REG	Renewable Energy Generation
RIP	Regional Infrastructure Plan
RRFE	Renewed Regulatory Framework for Electricity Distributors
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SCADA	Supervisory Control and Data Acquisition
TUL	Typical Useful Life
UG	Underground
WIP	Work In Progress

5.2 Distribution System Plan

Distributors are encouraged to organize the required information using the section and subsection headings indicated from here onwards.

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 of 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 of the current cost of service application.

Northern Ontario Wires Inc. ("NOW Inc.") 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 (the "Filing Requirements") as part of its 2025 Cost of Service Application (the "Application").

The DSP is a stand-alone document that is filed in support of NOW Inc.'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 2017 to 2023, with 2024 being the bridge year, and a forecast period of 2025 to 2029, with 2025 being the Test Year.

The DSP contents are organized into three major sections:

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

The materiality threshold for NOW Inc. is $50,000, and detailed descriptions of specific projects/programs exceeding the materiality threshold are provided in Section 5.4.2.1 and Appendix A. Other pertinent information relevant to this DSP is included in the Appendices.

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

The intent of this DSP is to support NOW Inc.'s plan to:

- add customer facing software as requested by the customer base;
- increase spending on system renewal as driven by asset management results;
- continue the voltage conversion programs to improve operational efficiencies; and

- manage electricity rates as requested by customers.

5.2.1 Distribution System Plan Overview

The distributor must provide a high-level overview of the information filed in the DSP and is encouraged not to unnecessarily repeat details contained in the rest of the DSP. This overview should include capital investment highlights and changes since the last DSP. A distributor should list out the objectives it plans to achieve through this DSP, which will be used as a baseline comparison in the performance measurement section below. This DSP will be used to inform and potentially support any requests for incremental capital module (ICM) funding during the 5-year DSP term.

This section provides the OEB and stakeholders with a high-level overview of the information filed in the DSP, including key elements of the DSP, sources of expected cost efficiencies, the period covered by the DSP, the vintage of the information, an indication of important changes to NOW Inc.'s asset management processes, and aspects of the DSP that are contingent on the outcome of ongoing activities or future events.

5.2.1.1 Description of the Utility Company

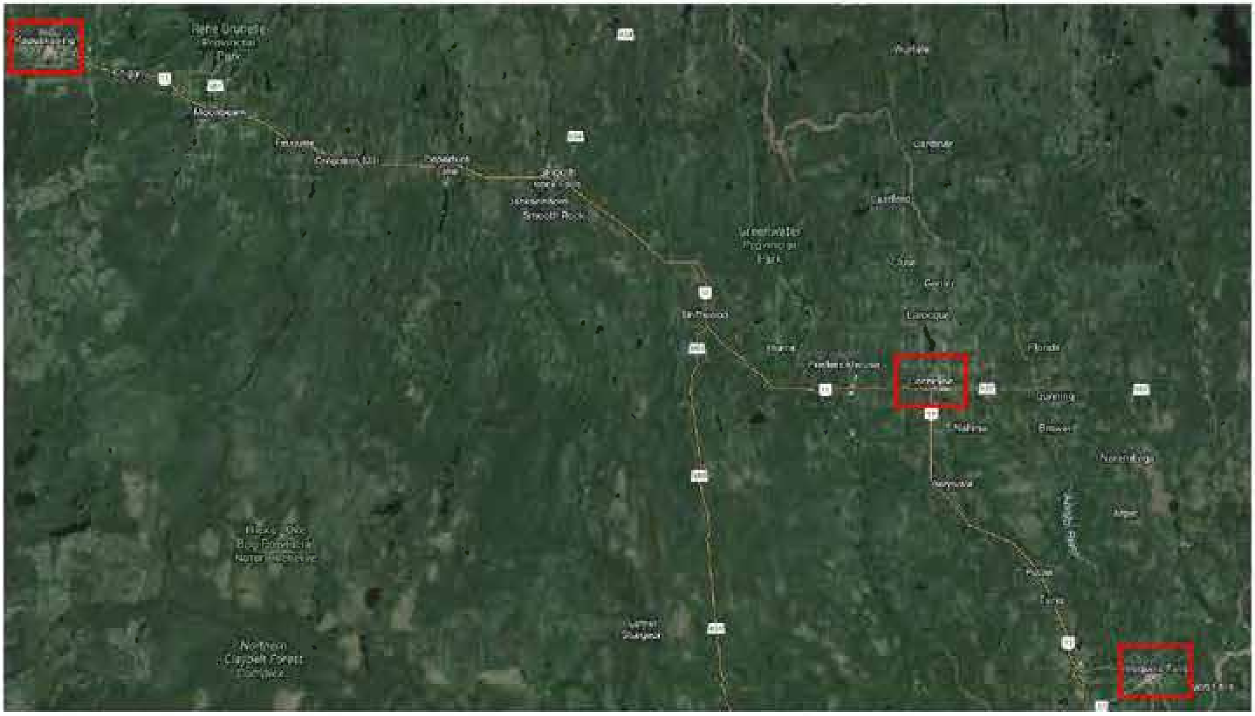
Brief overview of the NOW (regions served, size of service area, total number of customers).

NOW Inc. is a local distribution company ("LDC") holding Distribution License ED-2003-0018. As mandated by the *Electricity Act, 1998*, NOW Inc. was incorporated in 1999 during the amalgamation of the Cochrane Public Utilities Commission and the Iroquois Falls Hydro Electric Commission. In the year 2000, NOW Inc. purchased the assets of Kapuskasing Wires Inc.

5.2.1.1.1 Service Area

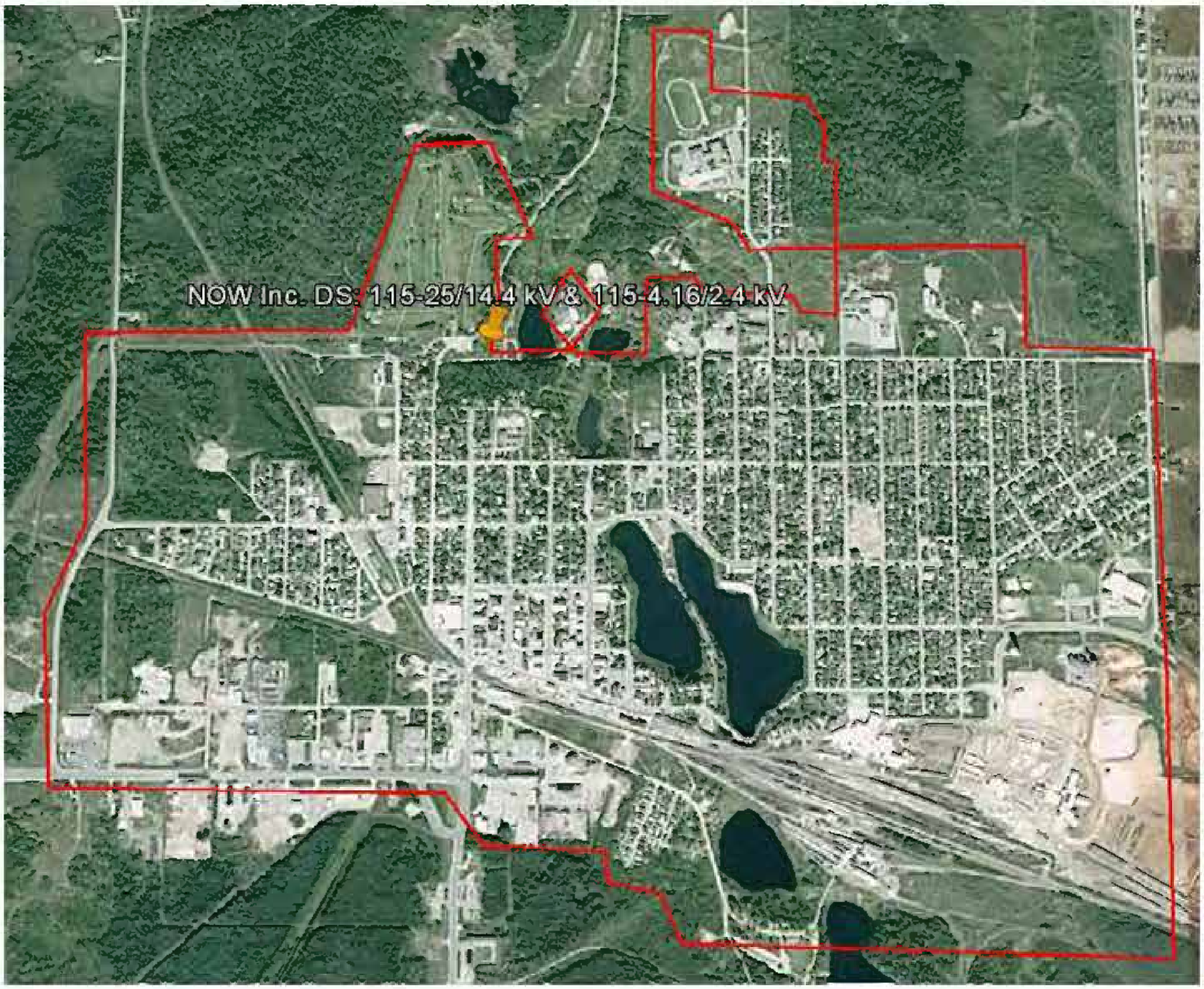
NOW Inc. owns and operates electrical infrastructure, servicing customers in the Town of Cochrane, the Town of Iroquois Falls, and the Town of Kapuskasing. These non-contiguous service areas depicted in Figure 5.2-1 and total 28 square kilometers, all of which is classified as urban.

Figure 5.2-1: NOW Inc.'s Service Area – Kapuskasing, Cochrane, and Iroquois Falls



NOW Inc. owns a total of six distribution substation ("DS"). In Cochrane, NOW Inc. receives power at 115 kV from Hydro One Networks Inc. ("HONI") and steps it down to 25/14.4 kV and 4.16/2.4 kV. Figure 5.2-2 depicts NOW Inc.'s service area in the Town of Cochrane outlined in red, and the location of the two DS (at the same location).

Figure 5.2-2: NOW Inc.'s service area – Town of Cochrane

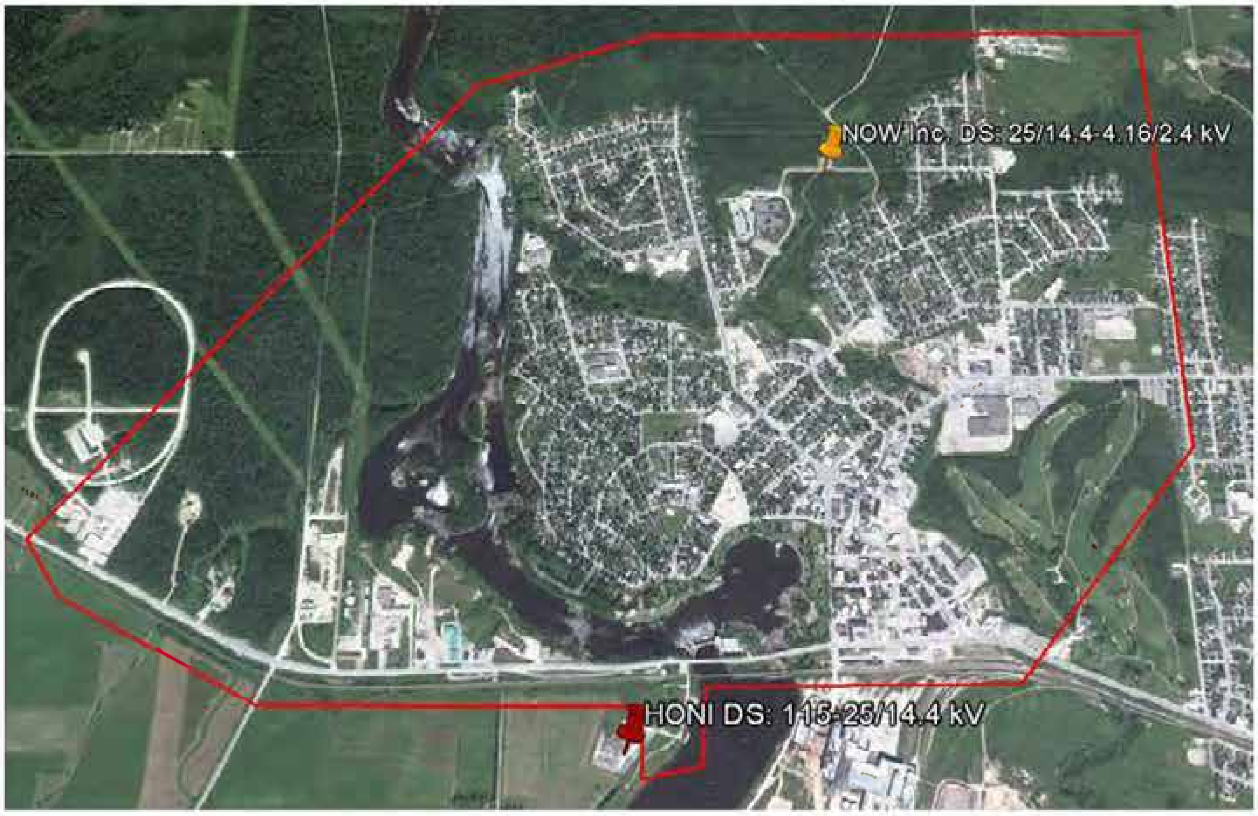


In Iroquois Falls, NOW Inc. receives power from the HONI-owned Iroquois Falls DS feeders F1 and F2 at 12.5/7.2 kV. Now Inc. owns two DS in Iroquois falls which step power down to 4.16/2.4 kV and one DS which steps power down to 2.4 kV delta. NOW Inc. is in the process of converting its 2.4 kV delta system to 12.5/7.2 kV, at which point it will retire the 12.5/7.5-2.4 kV delta DS. Figure 5.2-3 depicts NOW Inc.'s service area in the Town of Iroquois Falls outlined in red, the location of the three DS owned by NOW Inc., and the location of the HONI-owned DS.

Figure 5.2-3: NOW Inc.'s service area – Town of Iroquois Falls

In Kapuskasing, NOW Inc. receives power from the HONI-owned Kapuskasing DS feeder M2 at 25/14.4kV. NOW Inc. owns one DS in Kapuskasing which steps power down to 4.16/2.4 kV. NOW Inc. is in the process of upgrading the 4.16/2.4 kV system in Kapuskasing to 25/14.4 kV, which will eliminate the need for a DS in Kapuskasing. Figure 5.2-4 depicts NOW Inc.'s service area in the Town of Kapuskasing outlined in red, the location of the DS owned by NOW Inc., and the location of the HONI-owned DS.

Figure 5.2-4: NOW Inc.'s service area – Town of Kapuskasing



5.2.1.1.2 Corporate Ownership and Organization

NOW Inc. has a single shareholder – the Corporation of the Town of Cochrane – and is governed by a Board of Directors. The Board of Directors has nine members, who are appointed by the shareholder, the Town of Iroquois Falls, and the Town of Kapuskasing. The Board of Directors meets, at a minimum, quarterly and receives reports outlining financial, operational, and safety performance in addition to the progress in maintenance, operational, and capital programs.

NOW Inc.'s General Manager is accountable to the Board of Directors and its management level is accountable to the General Manager through business goals, the development and execution of annual budgets, and various standards and processes that apply to the distribution system assets. Accountability for financial and regulatory activities lies with the Chief Financial Officer, who oversees all financial reporting, assets funding provisions, and the budgeting process. Accountability for managing the lifecycle of existing assets, the installation of new developments, and the installation of new assets lies with the Operations Supervisor (in this instance, the General Manager and Operations Supervisor are the same individual). This role addresses long term planning issues, such as capacity and security and is accountable for system reliability.

5.2.1.1.3 Customers and Load

The three towns have a combined population of approximately 18,100. Similar to most communities in northeastern Ontario, there had been a decline in population predominantly due to job losses at paper mills and sawmills with a small increase in recent years.

NOW Inc. serves 5,961 customers as of the 2023 year-end customer count. NOW Inc. has three customer classes: residential, General Service less than 50 kW ("GS<50"), and General Service greater than 50 kW ("GS>50. Table 5.2-1 and Figure 5.2-5 breaks down the year-end customer counts by customer class for the years 2015 to 2022.

Table 5.2-1: Changing Trends in Customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2023	5,181	710	70	5,961
2022	5,159	715	67	5,941
2021	5,158	709	67	5,934
2020	5,150	706	73	5,929
2019	5,165	742	70	5,977
2018	5,127	724	68	5,919
2017	5,194	733	53	5,980

Figure 5.2-5: Changing Trends in NOW Inc.'s Customer Base

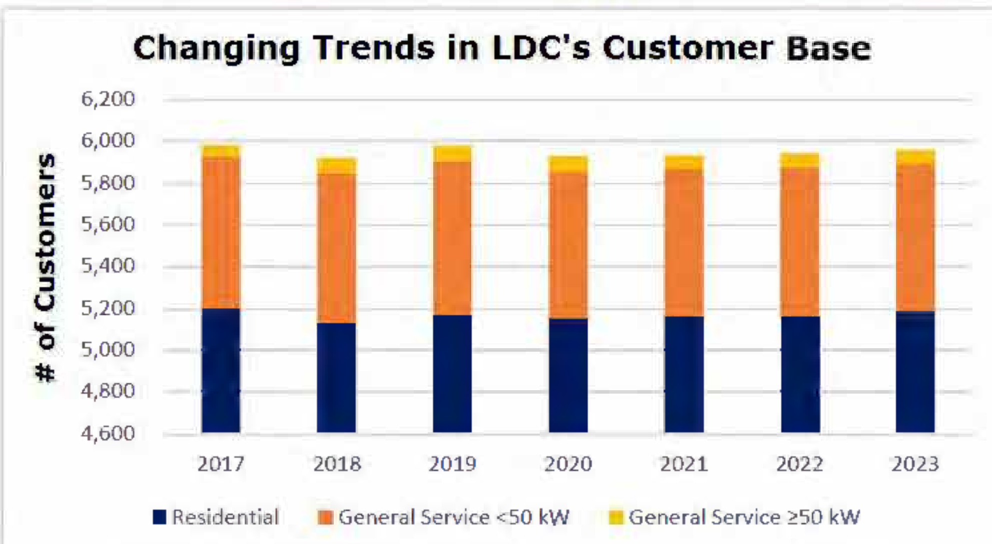


Table 5.2-2 summarizes the winter peaks, summer peaks, and average peaks in kilowatts (kW) for a NOW Inc. over the years 2017 to 2022. The 'winter peak' column indicates the maximum electricity demand during the winter months, typically occurring during periods of high heating usage. Conversely, the 'summer peak' column reflects the highest electricity demand experienced in the summer months, often due to increased cooling needs. The 'average peak' column provides the average peak electricity demand observed throughout the respective years, offering insight into overall usage trends and grid management considerations. Energy consumption per customer will be partially reduced with energy conservation efforts and improved technology. However, it is also expected that with a greater uptake in items such as EV's the trend will slightly move upwards.

Table 5.2-2: Peak System Demand Statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2023	22,129	20,464	19,874
2022	23,217	18,600	19,252
2021	22,199	20,235	19,341
2020	21,659	19,688	19,245
2019	23,352	18,301	19,047
2018	23,485	18,711	19,431
2017	23,708	21,210	19,318

5.2.1.2 Capital Investment Highlights

NOW Inc.'s capital investments over the planning period have been aligned to the 4 categories of system access, system renewal, system service, and general plant outlined in the Filing Requirements. Table 5.2-3 presents NOW Inc.'s historical actuals and forecast expenditures for both capital and O&M categories.

Table 5.2-3: Historical and Forecast Capital Expenditures and System O&M

Category	Historical ($ '000)								Forecast ($ '000)				
	2017	2018	2019	2020	2021	2022	2023	2024*	2025	2026	2027	2028	2029
System Access (Gross)	2	13	2	31	44	6	35	-	15	15	15	15	15
System Renewal (Gross)	263	242	235	217	434	285	349	90	50	50	671	50	50
System Service (Gross)	427	487	361	395	341	282	61	456	6,785	4,233	5,007	3,861	1,090
General Plant (Gross)	153	140	77	193	39	373	282	1,327	64	706	64	64	646
Gross Capital Expenses	845	881	674	837	859	947	727	1,873	6,914	5,004	5,757	3,990	1,801
Contributed Capital	8	-	-	-	-	-	-	-	-	-	-	-	-
Net Capital Expenses after Contributions	836	881	674	837	859	947	727	1,873	6,914	5,004	5,757	3,990	1,801
System O&M	1,230	1,379	1,416	1,492	1,466	1,662	1,769	1,981	2,578	2,668	2,748	2,830	2,915

**2024 Estimates*

5.2.1.2.1 System Access

Summary of drivers & major projects proposed.

Capital investments in the system access category over the forecast period are driven by mandated service obligations to meter customers. NOW Inc. has budgeted for the replacement of smart meters, which have a useful life ranging from five to fifteen years and are beginning to fail. NOW Inc. has not budgeted for any expenditures due to customer service requests or other third-party infrastructure development requests.

5.2.1.2.2 System Renewal

Summary of drivers & major projects proposed.

Capital investments in the system renewal category over the forecast period are driven by assets at the end of their service life. NOW Inc. has three pole replacement programs – one for each Town – to replace poles that have reached the end of their service life, which is budgeted each year. In addition, NOW Inc. plans to replace transformers that are obsolete and at end of life in Cochrane area to enable the connection of the new Cochrane MTS.

5.2.1.2.3 System Service

Summary of drivers & major projects proposed.

Capital investments in the system service category over the forecast period are driven by system operational objectives in safety, efficiency, and reliability. In particular, NOW Inc. will carry on its voltage conversion programs in its K Kapuskasing and Iroquois Falls service areas. These programs will allow for the retirement of the 4.16kV system. The voltage conversion will allow NOW Inc. to:

- Reduced Operating & Maintenance (O&M) costs associated with maintaining and operating 4kV substations.
- The significant deferral of capital expenses by replacing and converting this end-of-life infrastructure, the majority of which has been identified as being in poor or very poor condition, so that the substation assets associated with these areas can be removed from service as opposed to replaced.
- Some reduction of system losses.
- Reduction in inventory due to removal of the 4.16kV operating voltage.

NOW Inc.'s largest capital expenditure will be its proposed new 25kV Cochrane Municipal Transformer Station (MTS). This new MTS will be a multi-year project with the new station being in-service in 2028. This new station is required to meet the increase in forecast load NOW Inc. is expecting, both from being informed by customers as well as the increase load due to electrification. A material narrative with more details on the new proposed MTS can be found in Appendix A.

Maintaining the current Cochrane Municipal Station without upgrades or new construction is not advisable due to its unsustainability and lack of immediate benefits. The existing infrastructure is outdated, heavily loaded, and at high risk of failure. This approach will likely lead to increased long-term maintenance costs, greater risk of overloads and system failures, and higher operational expenses due to declining equipment performance and escalating repair needs. Additionally, ongoing constraints from aging infrastructure and limited space at the current site will continue to create challenges, potentially resulting in higher future expenditures if investment is deferred.

5.2.1.2.4 General Plant

Summary of drivers & major projects proposed.

Capital investments in the general plant category over the forecast period are driven by improvements to operational efficiency, required software and hardware purchases to support day-to-day business activities, and non-distribution system equipment reaching its end-of-life. Capital expenditures to purchase tools and equipment have been budgeted each year of the forecast period to replace equipment that is no longer useful. NOW Inc. is planning on replacing two major vehicles within its fleet during the forecast period. Computer hardware expenditures are also budgeted each year of the forecast period to purchase new hardware, as necessary. Finally, computer software expenditures are budgeted each year of the forecast period.

5.2.1.3 Key Changes since Last DSP Filing

Where applicable, an indication of important changes since the last DS Plan filing.

There have been some changes that NOW Inc. has either implemented or experienced since its last DSP filing:

- NOW Inc. has carried out an ACA to inform some of its investment plans.
- NOW Inc. has witnessed a change in management and strategic direction.
- Similar to other utilities, COVID-19 impacted NOW Inc., causing disruptions in supply chains, labor delays, and increased costs. These challenges have influenced the amount of work NOW Inc. could perform and the associated expenses. Consistent with industry trends, NOW Inc. has seen significant rises in material and labor costs in recent years, resulting in an upward trend in its forecast expenditures.
- NOW Inc. has identified that the increase in electrification, , will likely have an impact on how it carries out its planning and forecasting. There is still a fair degree of uncertainty about the pace of electrification, which could cause uncertainty in its forecast. This means NOW Inc. will need to have plans that can be easily and quickly adapted.
- NOW Inc. has also improved its maintenance and inspection programs, aligning them to best practices, allowing them to make more informed decisions.
- New Website Applications: NOW Inc. has launched The Silverblaze Customer Portal, a software solution designed for utility companies to enhance customer engagement and self-service capabilities. Key features and benefits include Account Management, Billing History and Usage Data, Online Bill Payment, Payment Methods, Usage Monitoring, Interactive Customer Choice, and Green Button.
- Implementation of Go360 Outage Management Tool (currently ongoing): This tool will facilitate outage information delivery to the public through a web-based interactive GIS map accessible via a web browser. This innovative software will improve outage data tracking and create efficiencies for distribution system maintenance and regulatory reporting. Go360 Live Ops and Crew Ops will allow the power line technicians equipped with mobile tablets access to distribution

system and service order information anywhere via cellular data. With this information at hand crews can now work safer and more efficiently with all access at their fingertips.

5.2.1.4 DSP Objectives

A distributor should list out the objectives it plans to achieve through this DSP. This should include a reference to the four performance outcomes established by the OEB: customer focus, operational effectiveness, public policy responsiveness, and financial performance.

This DSP has been developed to achieve the four performance outcomes established in the RRF: customer focus, operational effectiveness, public policy responsiveness, and financial performance. To realize these four outcomes, NOW Inc. has outlined the following objectives:

- provide customers with a safe and reliable supply of electricity.
- operate effectively and efficiently, reducing costs where feasible.
- facilitate the connection of Renewable Energy Generation (“REG”),
- facilitate the electrification of the grid; and
- promote a culture of energy conservation.

5.2.2 Coordinated Planning with Third Parties

A distributor must demonstrate that it has coordinated 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, provide a brief explanation as to how.

For consultations that affect the DSP, a distributor should provide:

- *an overview of the consultation,*
- *relevant material supporting the effects the consultation had on the DSP*

An overview of any consultation(s) should include: The purpose and outcome 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 distributor should file the most recent regional plan (Integrated Regional Resource Plan, Regional Infrastructure Plan). In the absence of a regional plan, the distributor should file a Regional Planning Status Letter from the transmitter. Further, a distributor is required to identify 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.

<<Note: number & list of engagements may vary from one utility to the next>>

5.2.2.1 Customers

Purpose of the Consultation

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

Initiation and Participation

NOW Inc. regularly engages its customers through biennial customer engagement surveys conducted online. Additionally, NOW Inc. has conducted a specialized survey for this DSP, which was prepared in collaboration with BBA Inc. and administered in an online format between the days of July 26th and August 9th (see Appendix B). This was an open-online self-selection survey where respondents could connect with the survey link to complete their interview. The survey was promoted by NOW Inc.'s Customer Service Department through its website and social media accounts. Participants included residential and small commercial business customers.

Brief Description of Consultation

In addition to this customer engagement, other engagement activities have occurred. A summary of these activities and actions adopted is provided below:

Table 5.2-1: Summary of Customer Consultation, Needs and Actions Identified

List of customer engagement activities	List of customer needs and preferences identified	Actions taken to respond to identified needs and preferences
Customer Engagement Survey - July 2024 (Further described below in this section, see Appendix B for the survey)	• More information on power outages (times, location, length, etc.) • Current information on website • Communication	• Implementation of web-based OMS • Update website, social media • Provide additional conservation tips • Implementation of electronic billing
Town Hall Presentation: Development project around the sale of plots of land in Cochrane (involving developers)	• Reliable power supply • Cost-effective installation	• No Action take as it is conceptual at this point.
Regular contact with large customers	• Line loss efficiencies, power factor correction, business plans/direction	• Advised on replacing capacitors for increased line efficiency, factoring business plan in DSP planning

List of customer engagement activities	List of customer needs and preferences identified	Actions taken to respond to identified needs and preferences
Presentation to the Town of Kapuskasing and local hospital	• Reduce power outages • Manage tree vegetation	• Developed study for vegetation management • Fuse coordination study • Worked with H1 to implement new main breaker settings • Ramped up efforts and planning on Third-Party contractors for future efforts as applied in 2025 CoS Application
Bill inserts, website, and social media (ongoing)	• Provide current and useful information to customers	Not applicable
Front line customer interaction	• Day-to-day business activities	• Needs addressed as identified
Community events	• More information on the type of work done by NOW Inc. • Importance of safety	• Participation at community events, educating the general public including children about safety and the essential work done by NOW Inc.
Construction projects	• More information regarding the type of work to be done	• Customers within the area of construction are contacted in person or by door knockers
Regular contact with Service area Mayors	• Reliable power • Vegetation management	• Developed study for vegetation management • Ramped up efforts and planning on Third-Party contractors for future efforts as applied in 2025 CoS Application

Customer engagement is often done through NOW Inc.'s website, social media channels and customer engagement events. NOW Inc. utilizes surveys to educate, inform, and solicit input from customers regarding both current and future plans.

NOW Inc. and BBA Inc. designed the survey to primarily focus on the following six areas:

- Overall Performance
- Power Quality and Reliability
- Customer Preference Priorities
- Future Expenditures
- Billing and Payment
- Communications

In July and August 2024, NOW Inc. conducted its DSP customer engagement survey to help inform its DSP. Approximately 300 customers completed the survey online. The focus of this survey was to get final input and feedback on NOW Inc.'s proposed DSP plans.

Consultation Outcomes and Impact on this DSP

Of the approximate 300 customers participating in the survey, about 92% of them were residential customers, about 1% were commercial customers, and roughly 4% were both residential and commercial customers.

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

From the survey completed in July/August 2024, NOW Inc. concluded the following from the responses received:

- Overall Performance: About 60% of the customers were very satisfied with the electricity service from NOW Inc. while only 4% of them seemed to be very dissatisfied with the service. These results indicate a generally high level of satisfaction with the service, though there is a small group who are less satisfied.

- Power Quality and Reliability: The survey responses highlight the strong satisfaction among residential customers and demonstrate the effectiveness of service restoration for commercial clients, with opportunities to further enhance the experience for all customer segments. Approximately 49% of the residential customers rarely experience problems with their electricity service while 58% of the commercial customers sometimes experience flickering or brief power outages. About 58.33% of commercial customers and 65.75% of residential customers found the efforts to minimize power outages to be either "Very effective" or "Extremely effective." These results indicate that the majority view the efforts positively, reflecting strong satisfaction across both commercial and residential customers. Responses to survey questions in this category also indicated that a strong majority of customers across both segments are satisfied with the communication efforts during extended outages. The strong positive feedback from the majority of respondents highlights the effectiveness of the current approach in maintaining communication during outages and the utility's efforts to ensure consistent and reliable electricity service.

  Approximately 78% of commercial customers and 90% of residential customers acknowledged the importance of minimizing power outages. Among them, 33% of commercial customers and 19% of residential customers are even willing to pay more to support increased investment in keeping the power on. These results demonstrate a strong recognition across both customer groups of the importance of efforts to minimize power outages, with many expressing their support for ongoing investment in this area.

- <u>Customer Preference Priorities:</u> Reliable and safe power emerged as the top priority for both residential and commercial customers, who rated Northern Ontario Wires highly in this area. The positive response to maintaining low electricity costs, even if it compromises reliability, particularly among commercial customers, underscores the need for balanced investment. Although the company received lower ratings for its focus on aesthetics and innovation, these areas represent key opportunities for improvement. By addressing these aspects, Northern Ontario Wires can enhance overall service quality, justifying the need for additional spending to meet evolving customer expectations and ensure continued reliability and safety.

- <u>Future Expenditures:</u> Overall, respondents strongly support the proposed spending to meet increasing load demand and maintain reliability in the Cochrane area. Among the 107 respondents from Cochrane, 50% of commercial customers and 52.43% of residential customers agree with the investment to build a new Municipal Transformer Station, with additional recognition of its importance among those unwilling to pay more. The rate increase associated with this project would mainly impact commercial customers, as residential customers are protected under the Distribution Rate Protection program, ensuring no additional costs for them. These results underscore a strong consensus on the need to maintain and upgrade infrastructure to support Cochrane's growing energy needs while protecting residential customers from financial impact.

  The survey responses also reflect strong overall support for the ongoing voltage conversion projects in Kapuskasing and Iroquois Falls, underscoring the commitment of both commercial and residential customers to ensuring a reliable and efficient electricity supply.

- <u>Billing and Payment:</u> A vast majority of the respondents find the explanations of the charges on their bill to be clear. These results highlight the overall effectiveness of the billing explanations provided by NOW Inc., with the vast majority of customers perceiving them as clear and understandable. The results also indicate that the majority of customers perceive their billing as accurate, reflecting confidence in the billing system provided by NOW Inc. Most customers are aware of and open to the e-bill option, with a substantial number already utilizing this convenient service.

- <u>Communications:</u> The customers a high level of satisfaction among customers, reflecting positively on Northern Ontario Wires' efforts to provide the necessary information effectively. There were several suggestions noted for improvement, including better communication during power outages, the introduction of an app or online outage maps, and more frequent updates through various channels like newsletters, email, and social media. Some customers also recommend improving the website, offering real-time updates, and sending more information about energy-saving tips and billing options. Overall, while many are satisfied, there is a clear desire for more proactive and accessible communication, especially during outages.

5.2.2.2 Subdivision Developers

Typically, as NOW Inc. does not have major developments, it does not have any formal engagements. When and if any subdivision developers do want to connect to NOW Inc.'s, formal engagements are carried out, with clear requirements communicated.

5.2.2.3 Transmitter

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

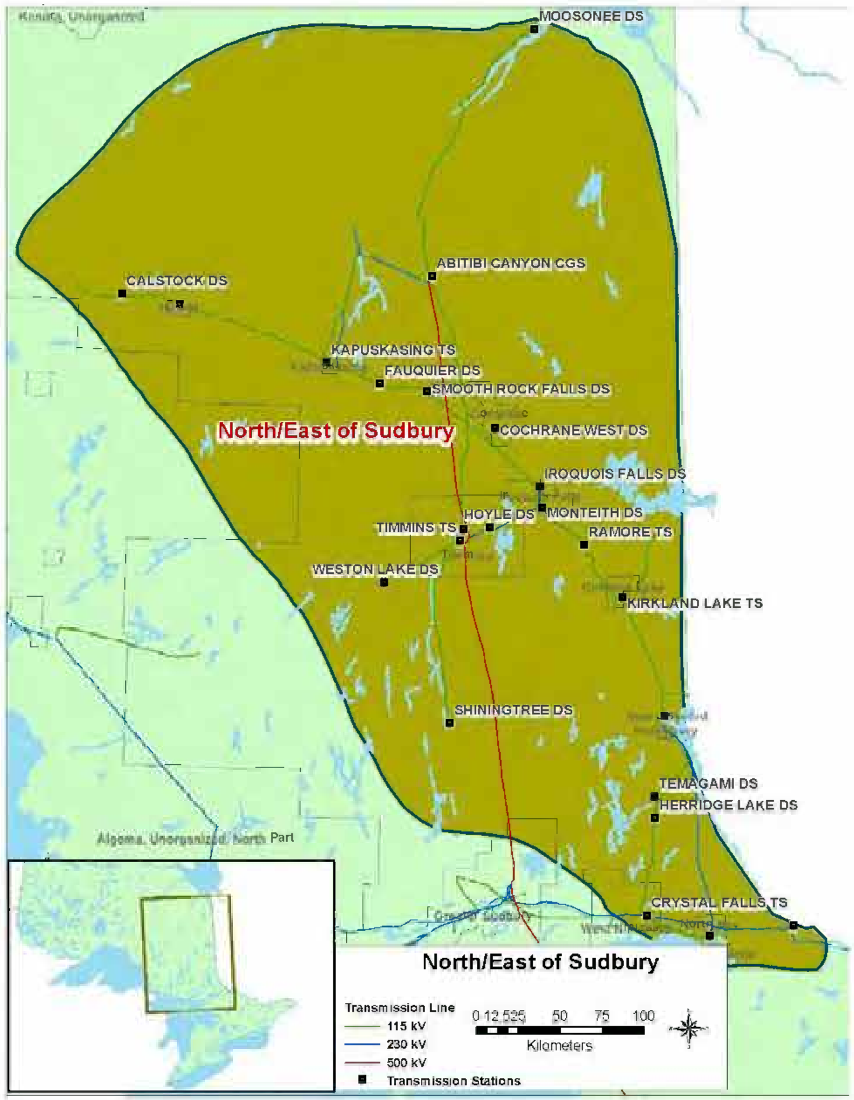
5.2.2.4 Other LDCs & IESO

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

5.2.2.5 Regional Planning Process

The IESO is facilitating regional system planning to ensure a reliable supply of electricity, considering conservation, generation, transmission and distribution, and innovative resources. NOW Inc. is in the North/East of Sudbury planning region, which is roughly bordered by Moosonee to the north, Hearst to the northwest, Ferris to the south, and Kirkland Lake to the east, as depicted in Figure 5.2-6. This region also includes Greater Sudbury Hydro Inc., HPDCL, North Bay Distribution Ltd., and HONI.

Figure 5.2-6: Map of the North/East of Sudbury planning region



The Regional Infrastructure Plan ("RIP") for this region was completed by HONI on May 10, 2023, and is attached as Appendix C. It provided a summary of needs and relevant wires plans to address needs for the region over a 10-year period from 2023-2033. Major projects that impacted NOW Inc. that are underway include the Kapuskasing Area Reinforcement – Install 115kV Reactive Devices which was planned to be completed in 2023. A specific concern being address is the replacement of low voltage circuit breakers, switches, station service equipment and protections due to end-of-life at Kapuskasing TS which is planned to be in service by 2030. These projects will be led by Hydro One Transmission. Finally, a remedial action scheme ("RAS") has been installed to provide voltage support in Kapuskasing area for system contingencies.

Aside from these projects, the RIP concluded that no further regional coordination is required.

5.2.2.6 Telecommunication Entities

In 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 provide:

- *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.*

<u>Consultations</u>

NOW Inc. 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. NOW Inc. is undertaking communications with Bell as they are currently approving a broadband expansion for the community of Iroquois Falls. Based on these consultations, most of the poles being replaced are joint use with Bell and are reaching the end of their lifespan. The fiber optic cables will be overlaid on the existing system.

<u>Result of Consultations</u>

Results of these consultations includes:

- Aligned project timelines and priorities for all entities.
- Communication of project status updates.
- Communication of project delays and reason(s) for the delays (i.e., supply chain.)
- Coordination of upcoming works.
- Comments on design reviews.
- Make-ready approvals.
- Coordination for telecommunication transfers.

Ongoing consultation and coordination ultimately help ensure that make-ready work is completed in a timely manner and that telecommunication entities are aware when it is complete.

5.2.2.7 CDM Engagements

Per the 2021 CDM Guidelines, the distributor should describe any CDM-related consultations (if applicable).

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

5.2.2.8 Renewable Energy Generation (REG)

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.

NOW Inc. is not forecasting any REG investments during the forecast period.

5.2.2.8.1 IESO Comment Letter

If there are REG investments proposed in the DSP, a distributor should 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.

NOW Inc. is not proposing any REG investments during the forecast period, and therefore does not require an IESO comment letter.

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 this DSP and, if applicable, improvements a distributor has implemented to achieve the objectives set out in this DSP Section.

5.2.3.1.1 Objectives for Continuous Improvement Set out in Last DSP Filing

This is not applicable.

5.2.3.1.2 Performance Scorecard

Explanations required for any objectives that have not been achieved, how it affects the DSP (if applicable) and improvements implemented to address/achieve these objectives.

NOW Inc.'s corporate emphasis on continuous improvement is reflected in all areas of its operations. Like most LDCs in Ontario, NOW Inc. must replace ageing, at risk of failure distribution infrastructure to ensure the safe and reliable supply of electricity. In addition to the strategic replacement of ageing assets, NOW Inc. continues to focus on core maintenance activities to reduce the disruption of electricity distribution to customers. NOW Inc. focuses on short- and long-term planning to ensure sufficient system capacity is available, and contingencies are in place should there be a loss of critical distribution infrastructure.

NOW Inc. monitors several performance measures, including those mandated by the OEB, that may assist in the utility's continuous improvement activities and satisfying customer requests. These measures can be divided into the following general groups:

1. Customer-oriented performance

2. Cost efficiency and effectiveness

3. Asset/system operations performance

Where applicable, the performance measures included on the scorecard have an established minimum level of performance to be achieved. The scorecard is used to continuously improve NOW Inc.'s asset management ("AM") and capital planning process. NOW Inc.'s current performance state is represented by NOW Inc.'s official scorecard results for the recent historical year as published by OEB. The scorecard is designed to track and show NOW Inc.'s performance results over time and helps to benchmark its performance and improvement against other utilities and best practices. The scorecard includes traditional metrics for assessing services, such as frequency of power outages and costs per customer. Table 5.2-5 summarizes NOW Inc.'s performance during historical years from 2017 to 2022.

The guidance provided by the OEB in the recently published Report of the Board: Electricity Distribution System Reliability Measures and Expectations (EB-2014-0189), indicates that it would like to use the average or arithmetic mean of the previous five years (or historical period) of data to establish performance expectations for the forecast period. Specifically, the OEB referred to SAIDI and SAIFI as the two reliability indicators that would benefit from using targeted goals.

Each metric provided in the table and subsections below influences NOW Inc.'s DSP to achieve the best performance for its customers. The following sections address performance metrics as published by the OEB in the performance scorecard and with additional performance metrics identified in OEB's Rate Filing Requirements.

Annual performance variances that are not within target ranges or meet minimal performance thresholds would result in senior management review of performance cause. This may result in review and changes to processes in order to bring performance back to target levels. NOW Inc. has been and continues to be, focused on maintaining the adequacy, reliability, and quality of service to its distribution customers. The historical performance measures include 2017 to 2022 to have a complete five-year historical performance assessment.

Table 5.2-4: DSP Performance Measures

Performance Outcome	Measure	Metric	2017	2018	2019	2020	2021	2022	2023	Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	1	1	1	-	-		100%	90%
		Scheduled Appointments Met on Time	100%	100%	100%	100%	100%	100%	100%	90%
		Telephone Calls Answered on Time	100%	100%	100%	100%	100%	100%	100%	65%
	Customer Satisfaction	First Contact Resolution	100%	100%	100%	100%	100%	100%	100%	No target
		Billing Accuracy	99.89%	99.95%	99.85%	99.90%	99.94%	99.97%	99.96%	98%
		Customer Satisfaction Survey	88.00%	88.00%	92.00%	92.00%	92.00%	88%	88.00%	No target
Operational Effectiveness	Safety	Level of Public Awareness	80.82%	80.82%	80.50%	80.50%	81.67%	81.67%	82.06%	No target
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	NI	C	C	C
		Number of General Public Incidents	0	0	0	0	0	0	0	0
		Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
	System Reliability	Ave. Number of Hours that Power to a Customer is Interrupted	3.43	4.73	2.87	5.59	1.86	1.11	8.06	3.69
		Ave. Number of Times that Power to a Customer is Interrupted	1.56	1.47	1.63	1.26	1.42	0.57	2.19	1.47
	Asset Management	Distribution System Plan Implementation Progress	Excellent	Excellent	Excellent	Excellent	Excellent	Excellent	Excellent	No target
	Cost Control	Efficiency Assessment	1	1	1	1	1	1	1	No target
		Total Cost per Customer	$ 666	$ 695	$ 715	$ 706	$ 704	$ 769	$ 847	No target
		Total Cost per km of Line	$ 10,757	$ 11,085	$ 11,551	$ 11,310	$ 11,287	$ 12,344	$ 13,645	No target
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation CIA Completed on Time	-	-	-	-	-	-	-	No target
		New Micro-embedded Generation Facilities Connected on Time	-	-	-	-	-	-	-	90%

Performance Outcome	Measure	Metric	2017	2018	2019	2020	2021	2022	2023	Target
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	1.24	1.8	1.7	1.45	1.25	1.38	1.19	No target
		Leverage: Total Debt (short-term & long-term) to Equity Ratio	1.04	1.06	0.92	0.84	0.82	0.89	0.9	No target
		Regulatory ROE – Deemed (included in rates)	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%	8.78%	No target
		Regulatory ROE - Achieved	6.24%	9.97%	10.92%	8.99%	10.48%	9.06%	4.44%	No target

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

a) SAIDI in 2018, 2020 & 2023
   - In 2018, this was largely due to the number of foreign interference issues (mainly birds) that have continue to increase and scheduled outages to upgrade the distribution system.
   - In 2020 and 2023, it was largely due to the number of foreign interference issues (mainly birds) that have continue to increase, adverse weather, and scheduled outages to upgrade the distribution system plan.

b) SAIFI in 2017, 2019 & 2023
   - One specific incident led to an 8.25-hour outage for 1,200 customers, resulting from the top part of a pole breaking at the communication attachment.
   - In 2019 and 2023, it was due to scheduled outages, tree contacts and foreign interference issues (mainly birds).

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)*

5.2.3.2.1 Service Quality Requirements

Explanations required for any underperformance, missed targets, material changes or declining trends, and whether and how the DSP addresses these issues.

The Distribution System Code sets the minimum service quality requirements that a distributor must meet in carrying out its obligations to distribute electricity under its license and the Energy Competition Act, 1998. As required by the OEB, NOW Inc. records and submits all performance measures, which are compared with the OEB's established levels to evaluate NOW Inc.'s customer service quality. The performance measures are described below, as defined in the Distribution System Code.

<u>Telephone Accessibility</u>

The OEB requires that qualified incoming calls to the distributor's customer care telephone number must be answered within the 30 second period as established below:

- For qualified incoming calls that are transferred to the distributor's interactive voice response system, the 30 seconds shall be counted from the time the customer selects to speak to a customer service representative.
- In all other cases, the 30 seconds shall be counted from the first ring.

The target for this metric is 65%.

Telephone Call Abandon Rate

As required by the OEB, the number of qualified incoming calls to a distributor's customer care telephone number that are abandoned before they are answered shall be 10% or less on a yearly basis. A qualified incoming call will only be considered abandoned if the call is abandoned after the 30 second time period has elapsed.

Connection of New Services

The OEB sets out the following requirements for the connection of new services:

- A connection for a new service request for a low voltage ("LV") (less than 750 V) service must be completed within five business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed by the customer and distributor.
- A connection for a new service request for a high voltage ("HV") (greater than 750 V) service must be completed within ten business days from the day on which all applicable service conditions are satisfied, or at such a later date as agreed to by the customer and distributor.

The target for this metric is 90%.

Appointment Scheduling

When a customer or a representative of a customer requests an appointment with a distributor, the distributor shall schedule the appointment to take place within five business days of the day on which all applicable service conditions are satisfied, or on such a later date as may be agreed upon by the customer and the distributor. This includes Underground Locate Requests.

The target for this metric is 90%.

Appointments Met

When an appointment is either:

- requested by a customer or a representative of a customer; or
- required by a distributor with a customer or a representative of a customer, the distributor must offer to schedule the appointment during the distributor's regular hours of operation within a window that is no greater than four hours. The distributor must then arrive for the appointment within the scheduled timeframe. This includes Underground Locate Requests.

The target for this metric is 90%.

Rescheduling a Missed Appointment

When an appointment with a customer or a representative of a customer is going to be missed, a distributor must:

- attempt to contact the customer before the scheduled appointment to inform the customer that the appointment will be missed; and
- attempt to contact the customer within one business day to reschedule the appointment.

The target for this metric is 100%.

Written Responses to Enquiries

A written response to a qualified enquiry shall be sent by a distributor within ten business days.

The target for this metric is 80%.

Emergency Response

Emergency calls (i.e. assistance by the distributor has been requested by fire, police, or ambulance services) must be responded to within two hours in rural areas and within one hour in urban areas. NOW Inc.'s entire service area is classified as urban.

The target for this metric is 80%.

Reconnection Performance Standards

Where a distributor has disconnected the property of a customer for non-payment, the distributor shall reconnect the property within two business days of the date on which the customer:

- makes payment in full of the amount overdue for payment as specified in the disconnection notice; or
- enters into an arrear's payment agreement with the distributor.

The target for this metric is 85%.

Billing Accuracy

The billing accuracy metric was established by the OEB in 2014. The percentage of bills accurately issued is calculated by subtracting the number of inaccurate bills issued for the year from the total number of bills issued for the year and dividing that number by the total number of bills issued for the year (the total number of bills issued for the year includes original and reissued bills). Accurate bills that need to be cancelled in order to correct another bill shall not be included in the calculation of billing accuracy measure. A distributor should not include customer accounts that are unmetered accounts (e.g. street lighting and unmetered scattered loads) or power generation accounts when calculating the percentage of accurate bills.

A bill is considered inaccurate if:

- the bill contains incorrect customer information, meter readings, or rates; or
- the bill has been issued to the customer and subsequently cancelled due to a billing error; or
- there has been a billing adjustment in a subsequent bill as a result of a previous billing error.

The target for this metric is 98%.

Table 5.2-6 presents NOW Inc.'s service quality measure performance for each of the years 2017 to 2022, as well as the minimum standards required by the OEB. NOW Inc. has met or exceeded each of the targets.

Table 5.2-5: Historical Service Quality Metrics

Service Quality Metric	2017	2018	2019	2020	2021	2022	2023	Minimum Standards
Low Voltage Connections	100.00%	100.00%	100.00%	N/A	N/A	N/A	100.00%	> 90%
High Voltage Connections	N/A	N/A	N/A	N/A	N/A	N/A	N/A	> 90%
Telephone accessibility	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	> 65%
Appointments met	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	> 90%
Written response to enquiries	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	> 80%
Emergency Urban Response	100.00%	100.00%	100.00%	N/A	N/A	100.00%	100.00%	> 80%
Emergency Rural Response	N/A	N/A	N/A	N/A	N/A	N/A	N/A	> 80%
Telephone call abandon rate	N/A	N/A	N/A	N/A	N/A	0.00%	0.00%	< 10%
Appointment scheduling	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	> 90%
Rescheduling a Missed Appointment	N/A	N/A	N/A	N/A	N/A	N/A	N/A	> 100%
Reconnection Performance Standard	100.00%	100.00%	100.00%	98.41%	88.04%	97.44%	100.00%	> 85%
New Micro-embedded Generation Facilities Connected	-	-	-	-	-	-	-	> 90%
Billing Accuracy	99.89%	99.95%	99.85%	99.90%	99.94%	99.97%	99.96%	> 98%

High voltage connections are shown as N/A since there were no high voltage connections from 2017-2023. Low voltage connections shown as "N/A" from 2020-2023 because there were no low voltage connections these years. Emergency response – rural is shown as

"N/A" each year because NOW Inc.'s entire service area is classified as urban. Emergency response – urban is "N/A" for 2020 and 2021 because there were not any emergency responses in those years. Telephone call abandon rates were "N/A" from 2017-2021 because there were no abandoned calls. Finally, missed appointments rescheduling is shown as "N/A" from 2017-2023 since there were no missed appointments to reschedule.

From 2017-2023, Northern Ontario Wires Inc. had no new micro-embedded generation facilities (microFIT projects of less than 10 kW). The minimum acceptable performance level for this measure is 90% of the time. Our workflow to connect these projects is very streamlined and transparent with our customers. NOW Inc. works closely with its customers and their contractors to tackle any connection issues to ensure the project is connected on time.

<u>Customer Satisfaction</u>

Customer satisfaction survey results and customer engagements play a crucial role in NOW Inc.'s success. The company maintains a rigorous standard for customer care and takes pride in the outcomes achieved. NOW Inc. is dedicated to providing exceptional customer service and value through its capital investments and operational activities. The company believes it has consistently met performance expectations for each metric, fostering credibility and trust among its customers. NOW Inc. has observed a positive trend in its customer satisfaction survey results over the historical period.

Table 5.2-7: Performance Measures - Customer Satisfaction (2017-2023)

Measure	Metric	2017	2018	2019	2020	2021	2022	2023	Target
Customer Satisfaction	First Contact Resolution	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	100.00%	N/A
	Billing Accuracy	99.89%	99.95%	99.85%	99.90%	99.94%	99.97%	99.96%	98%
	Customer Satisfaction Survey	88.00%	88.00%	92.00%	92.00%	92.00%	88.00%	88.00%	N/A

5.2.3.2.2 Reliability Requirements

Explanations required for any underperformance, missed targets, material changes or declining trends, and whether and how the DSP addresses these issues.

System reliability is an indicator of the quality of the electricity supply received by the customer. System reliability and performance are monitored via a variety of weekly, monthly, annual, and on-demand reports generated by the Smart Faulted Circuit Indicators, Customer Notification Bulletins from HONI, and the Outage Monitoring System ("OMS"). NOW Inc. collects and reports outage data using the standard format and codes specified in the "Reporting and record keeping requirements" (RRR) document. Calculations are made to determine the reliability indices for SAIDI, SAIFI, and CAIDI. The data is sorted to determine frequency and duration for each feeder as well as to determine the cause and affected components.

The reliability of supply is primarily measured by internationally accepted indices SAIDI and SAIFI as defined in the OEB's Electricity Reporting & Record Keeping Requirements dated May 3, 2016. SAIDI, or the System Average Interruption Duration Index, is the length of outage customers experience in the year on average, expressed as hours per customer per year. It is calculated by dividing the total customer hours of sustained interruptions over a given year by the average number of customers served. SAIFI, or the System Average Interruption Frequency Index, is the number of interruptions each customer experiences in the year on average, expressed as the number of interruptions per year per customer. It is calculated by dividing the total number of sustained customer interruptions over a given year by the average number of customers. An interruption is considered sustained if it lasts for at least one minute. NOW Inc.'s SAIFI target is 1.47 or less and its SAIDI target is 3.69 or less.

$$SAIDI = \frac{Total\ customer\ hours\ of\ sustained\ interruptions}{Average\ number\ of\ customers\ served}$$

$$SAIFI = \frac{Total\ customer\ interruptions}{Average\ number\ of\ customers\ served}$$

CAIDI or the Customer Average Interruption Duration Index is the average interruption time per customer affected and can be found by dividing the SAIDI value for the given year by the SAIFI value. CAIDI can also be viewed as the average restoration time. NOW Inc.'s CAIDI target is therefore 2.51 or less.

$$CAIDI = \frac{SAIDI}{SAIFI}$$

Loss of Supply ("LOS") outages occur due to problems associated with assets owned by another party other than NOW Inc. or the bulk electricity supply system. NOW Inc. tracks SAIDI and SAIFI including and excluding LOS. 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 NOW Inc. (i.e., force majeure or LOS) and whether the interruption was unforeseeable, unpredictable, unpreventable, or unavoidable.

NOW Inc.'s reliability metric values for the historical period, adjusting for LOS and MEDs, are shown in the tables below. As indicated in an earlier section, the main reasons for when NOW Inc. has not met reliability targets has largely been due to an increasing trend in foreign interference (mainly bird issues), as well as adverse weather in some years, and the increased number of scheduled outages to allow for capital investment work on the distribution system.

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

Metric	2017	2018	2019	2020	2021	2022	2023	Average
SAIDI	3.43	4.73	2.87	5.59	1.86	1.11	8.06	3.95
SAIFI	1.56	1.47	1.63	1.26	1.42	0.57	2.19	1.44
CAIDI	2.20	3.22	1.76	4.44	1.31	1.95	3.68	2.65

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

Metric	2017	2018	2019	2020	2021	2022	2023	Average
	Loss of Supply Adjusted (including MEDs, Excluding LOS)							
SAIDI	3.43	4.73	2.87	5.59	1.86	1.11	8.06	3.95
SAIFI	1.56	1.47	1.63	1.26	1.42	0.57	2.19	1.44
CAIDI	2.20	3.22	1.76	4.44	1.31	1.95	3.68	2.65
	Major Event Days Adjusted (including LOS, excluding MEDs)							
SAIDI	9.92	12.14	4.58	15.26	4.12	5.42	22.23	10.52
SAIFI	4.51	2.58	2.77	3.01	2.55	1.69	4.60	3.10
CAIDI	2.20	4.71	1.65	5.07	1.62	3.21	4.83	3.33
	Loss of Supply and Major Event Days Adjusted (excluding LOS and MEDs)							
SAIDI	3.43	4.73	2.87	5.59	1.86	1.11	8.06	3.95
SAIFI	1.56	1.47	1.63	1.26	1.42	0.57	2.19	1.44
CAIDI	2.20	3.22	1.76	4.44	1.31	1.95	3.68	2.65

NOW Inc.'s historical performance for SAIDI, SAIFI and CAIDI is visualized in the figures below.

Figure 5.2-7: Performance Measure – SAIDI

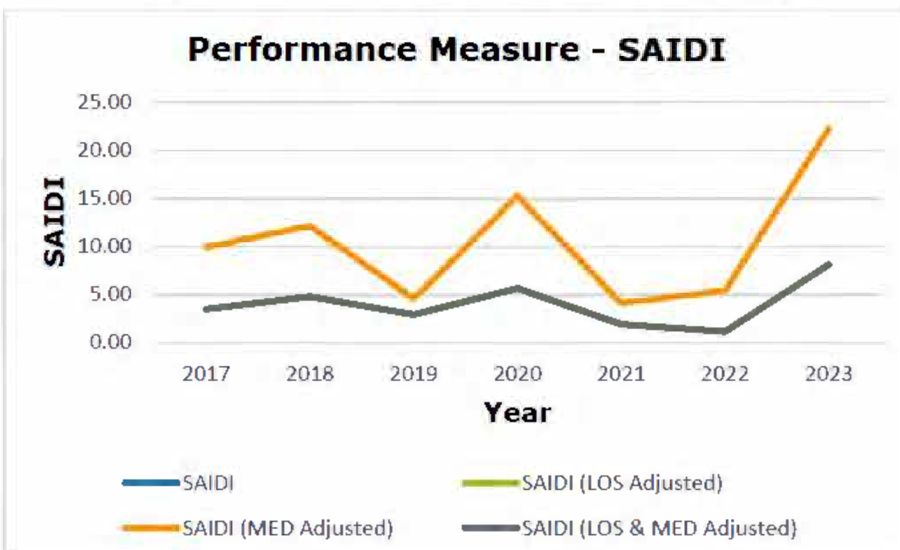


Figure 5.2-8: Performance Measures – SAIFI

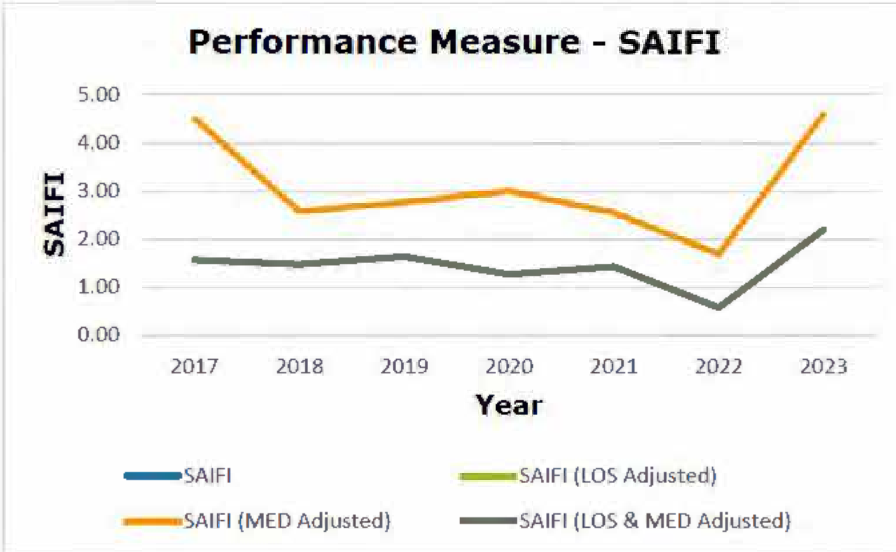
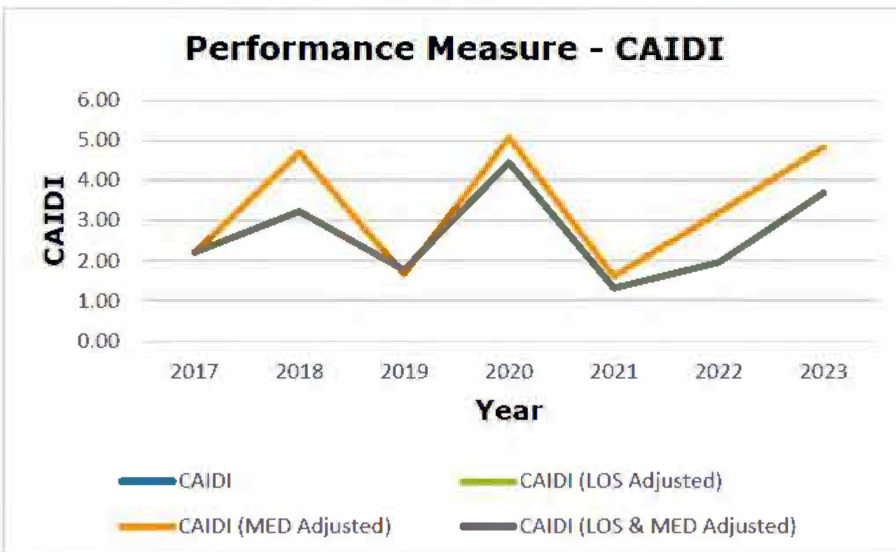


Figure 5.2-9: Performance Measure – CAIDI



5.2.3.2.3 Outage Details for Years 2017-2023

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

NOW Inc. has had no Major Event days since its last Cost of Service (CoS).

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 5.2-15 presents a summary of outages that have occurred within NOW Inc.'s service territory providing three different categorizations. A further breakdown by cause codes is provided in the following subsections.

Table 5.2-8: Number of Outages (2017-2023)

Categorization	2017	2018	2019	2020	2021	2022	2023
All interruptions	33	35	37	37	28	35	49
All interruptions excluding LOS	25	31	33	32	25	32	42
All interruptions excluding MED and LOS	25	31	33	32	25	32	42

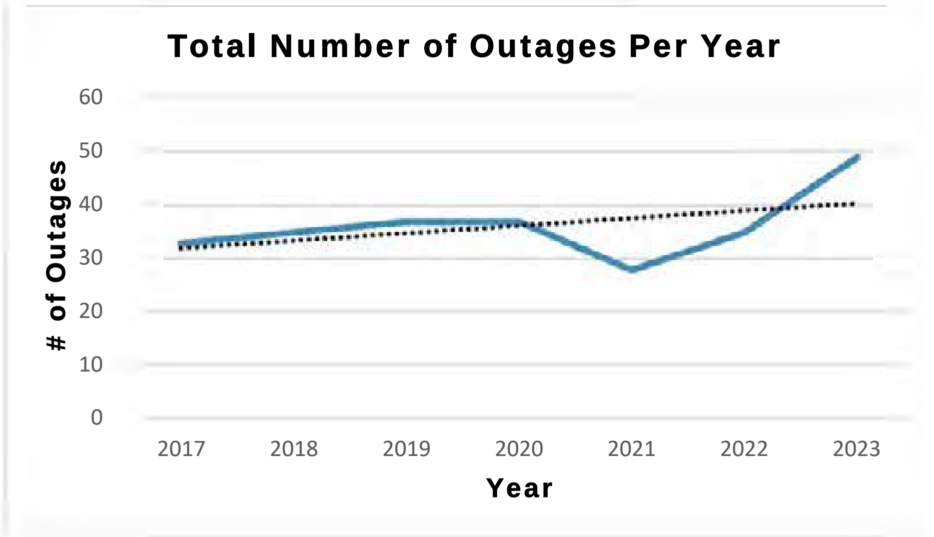
The following sections and figures provide the breakdown of historical outages for the historical period regarding the number of outages, the number of customers interrupted, and the number of customer hours experienced by the outages. Tracking outage performance by cause code provides valuable information on specific outage causes that need to be addressed to improve negative trending. As with the reliability indices, the historical performance range is used as a target and results outside this range indicate positive or negative trending. The following tables illustrate the number of MEDs over the historical period, the cause of them, and the customer hours interrupted.

Table 5.2-10 presents the count of outages broken down by cause code for the historical period. 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. NOW Inc. continues to assess and execute capital and O&M projects to manage the number of outages experienced.

Table 5.2-9: Outage Numbers by Cause Codes – Excluding MEDs

Cause Code	2017	2018	2019	2020	2021	2022	2023	Total Outages	%
0-Unknown/Other	0	0	0	2	0	0	5	7	3%
1-Scheduled Outage	4	8	3	2	1	8	4	30	12%
2-Loss of Supply	8	4	4	5	3	3	7	34	13%
3-Tree Contacts	1	2	5	2	6	8	4	28	11%
4-Lightning	0	0	0	0	0	0	1	1	0%
5-Defective Equipment	9	10	11	6	7	10	14	67	26%
6-Adverse Weather	2	3	4	7	2	2	1	21	8%
7-Adverse Environment	0	0	0	0	0	0	0	0	0%
8-Human Element	0	0	0	0	0	0	0	0	0%
9-Foreign Interference	9	8	10	13	9	4	13	66	26%
Total	**33**	**35**	**37**	**37**	**28**	**35**	**49**	**254**	**100%**

Figure 5.2-10: Total Number of Outages Per Year



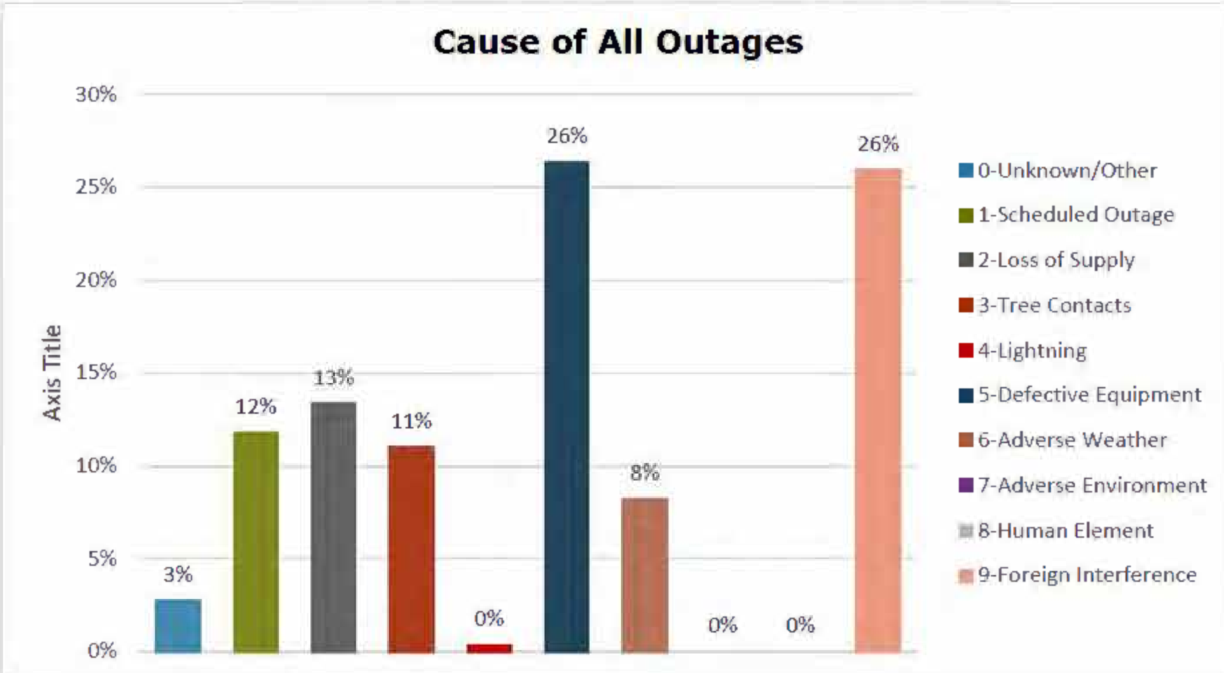
The total number of interruptions over a historical period varies from 28 to a high of 49 outages. The top three cause codes ranked by percentage share over the historical period are *Defective Equipment, Loss of Supply, and Foreign Interference*. A summary of the causes of outages within NOW Inc.'s system is presented in Figure 5.2-1 along with the percentage of overall outage incidents attributable to each cause type.

At 26%, Foreign Interference represents the joint largest cause for outages. Foreign Interference includes animal interference, dig-ins, vehicle collisions, vandalism, and/or foreign objects. Predominately for NOW Inc., there has been an increasing trend in bird issues that has contributed to these outage types. Unfortunately, many of these factors are outside NOW Inc.'s control with very few practical options to minimize these issues.

At 26%, Defective Equipment represents the joint largest cause for outages on NOW Inc.'s distribution system. Defective Equipment outages result from equipment failures due to condition deterioration, ageing effects, manufacturing defects, or imminent failures detected from regular maintenance programs.

At 13%, Loss of Supply is the next largest cause of outages. These are due to loss of supply by Hydro One. These outages are outside of NOW Inc.'s control; however, communication has been had with Hydro One to understand if these can be reduced in the future.

Figure 5.2-11: Percent of Outages by Cause Code



Analysis of outage frequency by cause code reveals that the primary causes are foreign interference and defective equipment. Defective equipment issues are predominantly attributable to aging assets, including connection points, ceramic insulators, and ceramic cutout switches. Foreign interference primarily involves animal-related incidents or mechanical equipment impacts. NOW Inc.'s system renewal projects/programs and voltage conversion projects replace assets at the end of their service life, which is expected to reduce the number of outage due to defective equipment. Additionally, animal guards will be installed in identified, problematic areas in order mitigate foreign interference outages.

Table 5.2-10: Customers Interrupted Numbers by Cause Codes

Cause Code	2017	2018	2019	2020	2021	2022	2023	Total CI	%
0-Unknown/Other	0	0	0	301	0	0	173	474	0%
1-Scheduled Outage	342	3030	142	18	32	201	2135	5900	4%
2-Loss of Supply	17748	6586	6787	10481	6738	6720	14513	69573	53%
3-Tree Contacts	2	40	69	35	3339	375	4864	8724	7%
4-Lightning	0	0	0	0	0	0	2234	2234	2%
5-Defective Equipment	6352	2717	9349	2292	4570	2648	1517	29445	23%
6-Adverse Weather	303	2887	35	4738	50	35	7	8055	6%
7-Adverse Environment	0	0	0	0	0	0	0	0	0%
8-Human Element	0	0	0	0	0	0	0	0	0%

Cause Code	2017	2018	2019	2020	2021	2022	2023	Total CI	%
9-Foreign Interference	2387	95	139	126	466	135	2330	5678	4%
Total	27134	15355	16521	17991	15195	10114	27773	130083	100%

Figure 5.2-12: Total CI over Historical Years

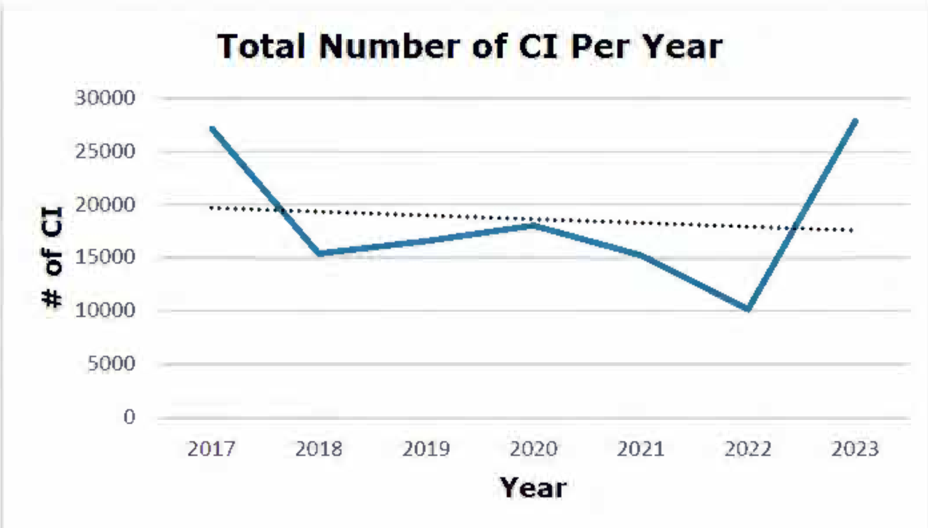
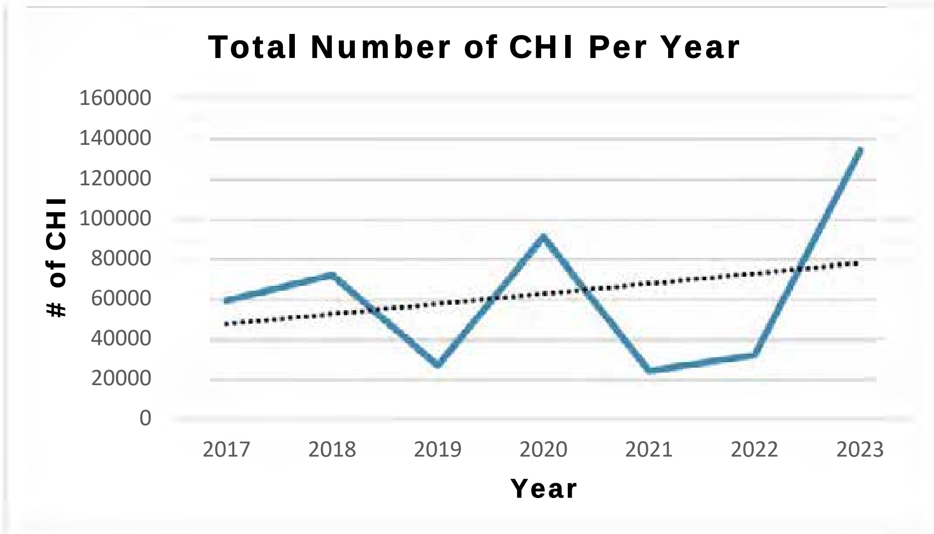


Table 5.2-11: Customer Hours Interrupted Numbers (rounded) by Cause Codes

Cause Code	2017	2018	2019	2020	2021	2022	2023	Total CHI	%
0-Unknown/Other	0	0	0	3	0	0	525	528	0%
1-Scheduled Outage	2469	13154	930	60	160	794	19430	36997	8%
2-Loss of Supply	39075	44222	10182	57833	13476	25760	85607	276155	63%
3-Tree Contacts	4	55	243	88	5710	594	14892	21585	5%
4-Lightning	0	0	0	0	0	0	2793	2793	1%
5-Defective Equipment	15393	2021	15487	10266	4824	5162	4162	57315	13%
6-Adverse Weather	2033	12811	232	22753	175	63	8	38074	9%
7-Adverse Environment	0	0	0	0	0	0	0	0	0%
8-Human Element	0	0	0	0	0	0	0	0	0%
9-Foreign Interference	731	136	200	210	183	48	6871	8378	2%
Total	59705	72398	27274	91212	24528	32420	134287	441823	100%

Figure 5.2-13: Total CHI over Historical Years



When analyzing CI and CHI, Loss of Supply, Defective Equipment, and Adverse Weather are the top contributing causes, as seen in Table 5.2-14 and Table 5.2-15.

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

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

Defective Equipment are addressed and invested in as outlined previously. The top cause code that can be controlled and managed by NOW Inc. is Defective Equipment. As previously noted, there are several ongoing and planned efforts to manage the number of controllable outages and continue meeting reliability targets. These efforts include ongoing testing, inspection, and maintenance of assets to identify and mitigate potential problems, in addition to planned capital investment programs to replace assets before experiencing a failure that may cause an outage.

5.2.3.3 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. Distributors who wish to establish performance expectations based on something other than historical performance should provide evidence of their capital and operational plan and other factors that justify the reliability performance they plan to deliver. Distributors should also provide a summary of any feedback from their customers regarding the reliability of the NOW Inc.'s distribution 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.

NOW Inc. does not use any additional metrics to track its reliability, beyond what is reported to the OEB.

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 provides an overview of NOW Inc.'s asset management process, an overview of the assets managed by NOW Inc., and a presentation of its asset lifecycle optimization policies and practices.

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).

NOW Inc. is committed to providing its customers with a safe and reliable electricity supply while operating effectively and efficiently at an equitable cost. NOW Inc. strives for excellence and continuous improvement in order to maximize shareholder value. Based on these corporate goals, NOW Inc.'s asset management objectives are prioritized as follows:

1. Operating a safe electrical system for employees and the public.
2. Meeting regulatory requirements.
3. Engaging in environmental protection.
4. Accommodating load growth and new customer connections.
5. Delivering a reliable supply of electricity.
6. Managing costs and rate stability.

These AM objectives form the high-level philosophy framework for NOW Inc.'s capital program. They define the content of the programs and the major projects in the capital expenditure plan needed to sustain NOW Inc.'s electrical distribution system, guiding NOW Inc. in making effective capital investment decisions, which inherently make the best use of assets and maximize their value to the company. Each objective has been integrated into NOW Inc.'s capital investment process to prioritize investments.

Safety is NOW Inc.'s top priority in every aspect of its business. NOW Inc. always strives to maintain and operate its electrical system in such a way that poses minimal hazard to its employees and the public. Meeting regulatory requirements set out by the OEB is the next priority, since the OEB's mandate comes directly from the provincial government. Thirdly, NOW Inc. prioritizes environmental protection, but this is not usually a driver for investment due to the nature of NOW Inc.'s system. NOW Inc.'s fourth priority is to provide power to its customers by accommodating load growth and new customer connections, which relates to its fifth priority of delivering power reliably. Finally, NOW Inc. aims to improve its operational efficiency and manage costs in order to keep electricity prices low for its customers.

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.

NOW Inc. has been developing an asset management system that integrates scoring and condition assessment data with specific assets. This system provides visibility to prioritize asset replacement efficiently and proactively. Data is collected by NOW Inc.'s staff and third-party contractors to ensure a timely understanding of system conditions and priorities. The data is continually reviewed by staff and updated in the system. This process also enhances crew safety by identifying risk factors within the system. The system will continue to evolve, with increasing reliance on internal resources.

5.3.1.3 Process

A distributor should provide the processes used to identify, select, prioritize (including reprioritizing investments over the five-year term), optimize 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 demonstrate how it does grid optimization using an approach that considers the distributor's whole system. This should include, 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.

A distributor must also demonstrate that it has a planning process for future capacity needs of the distribution system, which must include, among others, increased adoption of electric vehicles. On November 2, 2022, the OEB posted the "Load Forecast Guideline for Ontario" provided by the Regional Planning Process Advisory Group (RPPAG), which provided guidance in the development of demand forecasts to increase consistency among distributors. Distributors should consider this guidance when developing their load forecasts. The guidance recommended a sensitivity analysis to capture uncertainty in the demand forecast and noted "one of the evolving components with respect to the demand for electricity is electrification which is expected to change the growth patterns such as they are not well represented by historical trends."

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.

Asset management systems used by NOW Inc. include inspection and maintenance databases, electronic records of inspection and maintenance activities (improvements currently underway), an asset register, and a GIS. When an asset is serviced or refurbished, a paper record is generated; when an asset is replaced, the information is uploaded onto a spreadsheet. NOW Inc. also uses its accounting/inventory system to track changes and has established a system of inspection and performance reporting procedures, which satisfy the OEB reporting requirements. NOW Inc. uses input data and information to enable it to determine its operating and capital expenditure plans.

Inputs:

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

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

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

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

Asset needs directly inform the development of System Renewal investment. A substantial portion of the System Renewal category will fund the replacement of assets that do not meet the criteria to remain in service across all major distribution asset categories.

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

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

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

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

System Planning: Consideration is given regarding NOW Inc.'s expected load growth within its service area which is driven by known projects coming from consultations with the municipality, developers, and customers, as well as looking at historical trends, planning reports from regional planning, OEB guidance and bulletins, and IESO's planning outlook.

These inputs assist in the understanding of the impacts that EVs or the electrification of other historically alternatively sourced fuels may have on the distribution system in the future and allows NOW Inc. to prepare and incorporate these impacts into their investment plans. Potential system constraints and/or areas where fortification or upgrades of the distribution system may be needed to accommodate this are then identified.

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

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

Project Identification:

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

For assets that can be refurbished or upgraded to extend their lifespan at a lower cost, this strategy may be considered for implementation. For example, sandblasting and repainting of padmount transformers where the shell is prematurely rusting but the electrical asset is still good.

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

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

Different investment categories are then budgeted for based on a combination of the above inputs. Figure 5.3-1 and Figure 5.3-2 below represents the overall planning process for projects within the four investment categories.

Demographics and condition data are used to plan capital expenditures in the system renewal category, as summarized in Figure 5.3-1. Assets are grouped by age and condition to manage them better and are replaced strategically in overhead and underground rebuild projects based on inspections and demographics. Underground cables only account for 1% of NOW Inc.'s distribution system, and no underground rebuilds have been planned over the forecast period. Age demographics are used to plan the number of poles for replacement, while line patrols identify the worst poles for replacement as part of the pole replacement programs. Substation maintenance records as well as the Transformer Oil Analysis Report are used to plan substation refurbishments.

Figure 5.3-1: Planning Process for System Renewal Projects

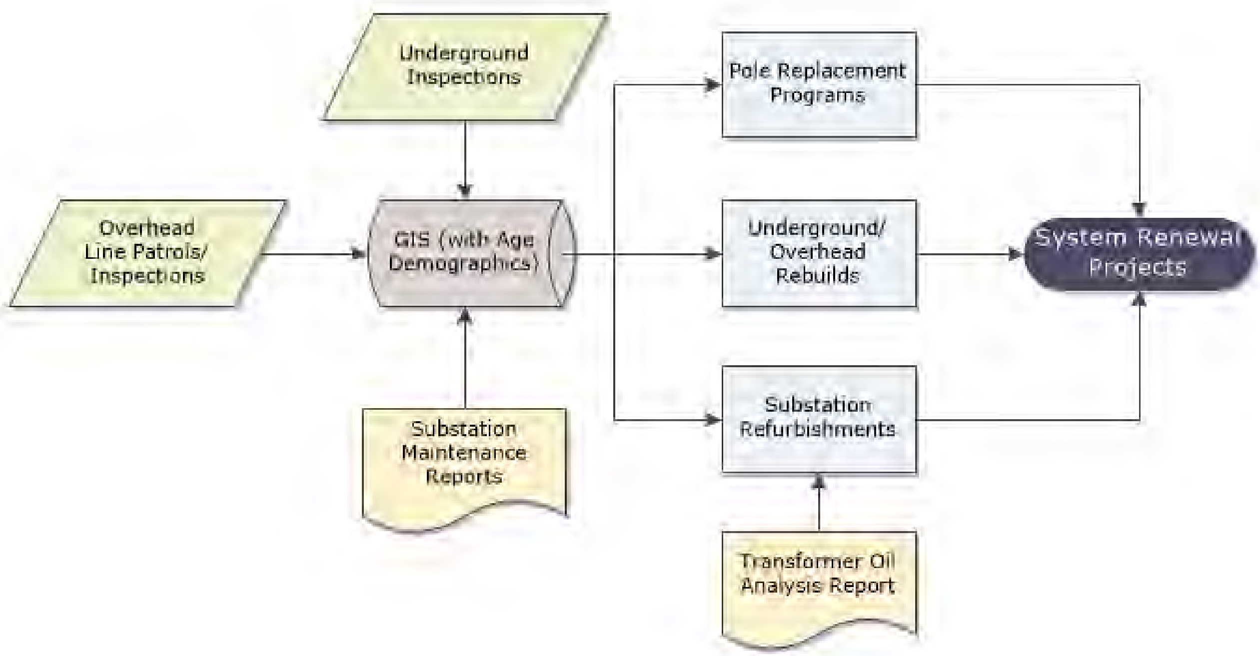


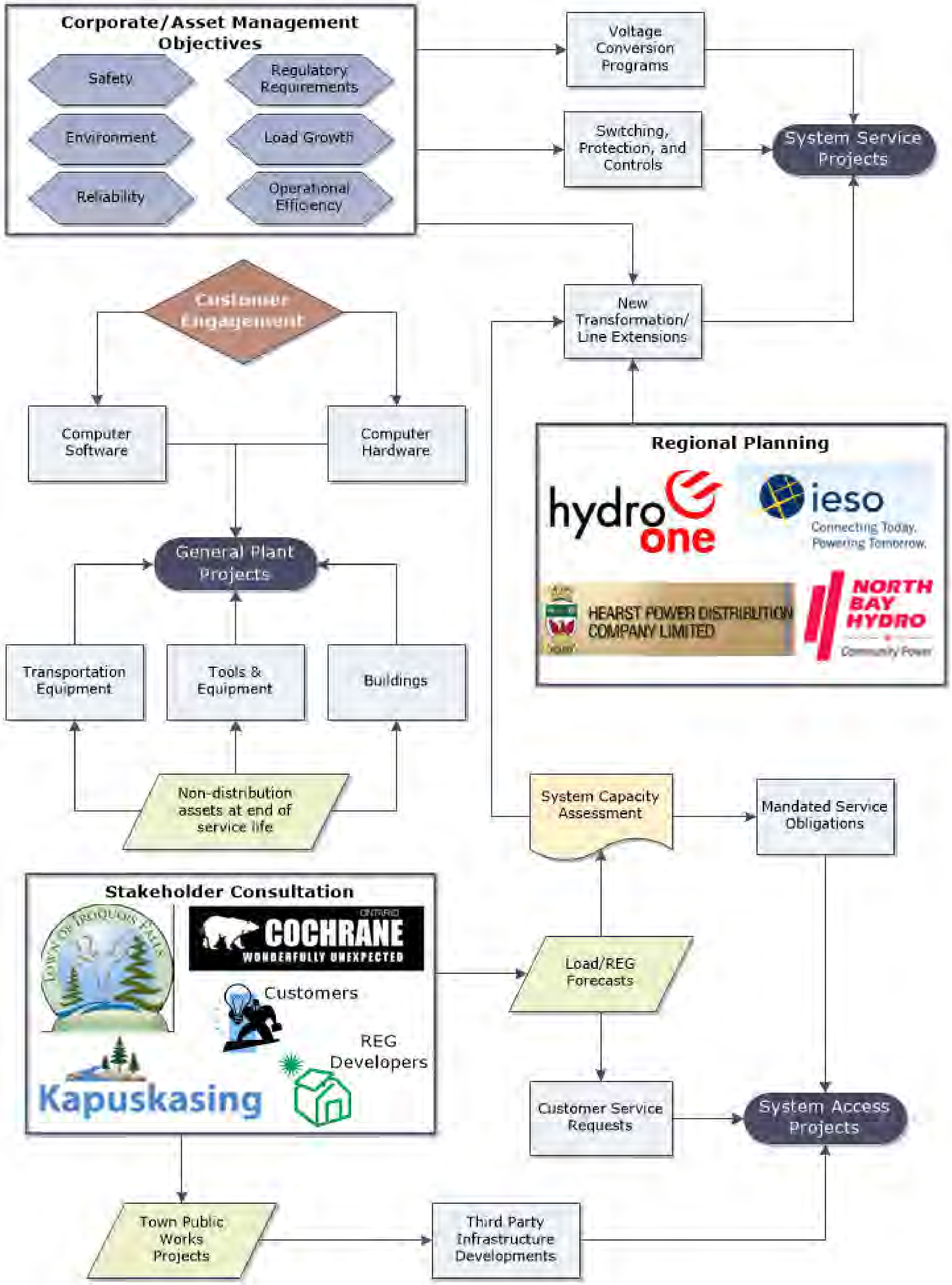
Figure 5.3-2 summarizes the planning process for the remaining three investment categories: system access, system service, and general plant. Stakeholder consultations with the three Towns, customers, and REG developers are important to identify Town public works projects and load and REG connection forecasts. These drive system access

projects due to third party infrastructure developments, customer service requests, and mandatory service obligations such as metering.

The system capacity assessment identifies system service projects in new transformation and line extensions, in conjunction with regional planning where long term load transfers or other solutions may exist. Load growth and system capacity are not drivers for NOW Inc. over the forecast period. NOW Inc.'s asset management objectives identify other system service projects, including voltage conversions driven by safety, operational efficiency, and reliability. NOW Inc. has not planned any projects in switching, protection, and controls over the forecast period.

NOW Inc.'s asset management objectives also identify general plant expenditures in computer hardware and software for improved operational efficiency, along with its customer engagement. Customers have asked for paperless billing and improved communication of outages. To accommodate these requests and improve its operational efficiency, NOW Inc. is planning to improve its GIS, OMS, and CIS. Other routine expenditures in computer hardware and software support NOW Inc.'s day-to-day business activities. Investments into transportation equipment, tools, and buildings are driven by fully depreciated non-distribution assets requiring repairs or replacements.

Figure 5.3-2: Planning process for System Access, System Service and General Plant projects



Project Prioritization:

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

System Access projects, which are non-discretionary in nature, are typically given top priority, as only work that addresses imminent health and safety issues is given a higher priority. These are identified through customer interactions, information from the municipality, and developers. The timing and cost of these projects are driven by the requesting party and are budgeted and resourced to meet these requirements. Projects driven by regulatory requirements (e.g., mandated by a governing body or regulator) are also given top priority as these are typically mandated to fulfill all regulatory obligations in NOW Inc.'s distribution license. Once all non-discretionary projects have been identified, the rest of the System Renewal, System Service and General Plant projects and programs are planned to improve NOW Inc.'s performance with respect to one or more of its objectives of safety, regulatory, environment, load growth, reliability, and efficiency. For the purpose of ranking and prioritizing projects/programs, these objectives are numerically weighted as shown in Table 5.3-1.

Table 5.3-1: Objective weights applied to project prioritization

Objective	Numeric Weight
Operating a safe electrical system for employees and the public	10
Meeting regulatory requirements	8
Engaging in environmental protection	7
Accommodating load growth and new customer connections	6
Delivering a reliable supply of electricity	5
Managing costs and improving efficiency	4

Figure 5.3-3: Summary of risk scores by asset class

NOW Inc. Risk Analysis

Asset Class / Risk Factor	Reliability	Safety	Environment	Efficiency	Load Growth
Substation Transformers	10	2	4	5	10
Substation Primary	10	2	0	4	
Substation Secondary	5	2	0	3	
Poles	4	4	0	2	
Pole-mounted Transformers	1	1	2	2	
Gang-operated Switches	2	1	0	2	
Overhead Conductors	2	1	0	2	
Pad-mounted Switchgear	3	4	0	4	
Pad-mounted Transformers	1	1	2	4	
Underground Cables	2	1	0	4	
Delta to wye conversion	0	10	0	0	
Voltage upgrade	0	0	0	6	
New Substation	10	5	5	10	10
Oil containment close to a waterway	0	0	10	0	
Improved clearances	0	6	0	0	

Each of the asset classes can be assigned a "risk score" between 0 and 10 – where 10 is the maximum – for each of the five risk factors of reliability, safety, environment, efficiency, and load growth. Figure 5.3-3 summarizes the risk factors for each asset class. These risk scores provide a risk comparison across asset classes used in the project prioritization process, where capital expenditures are selected and prioritized based on the risk analysis of the individual assets. The risks scores for the asset classes in the project scope are totalled and multiplied by the numeric weight of each risk factor (see Table 5.3-1). The asset risk scores are considered in conjunction with other project benefits that fall with these five risk factors along with regulatory.

The asset related impacts for each project/program are evaluated as per Figure 5.3-3 with the following scaling factors used for differentiation:

- Small conductors are more likely to fail than standard sizes; multiply impacts of small conductors by 2.
- Poles identified for replacement in the pole replacement programs are the very worst poles and are the most likely to fail; multiply impacts of pole replacement programs by 2.

In addition to the asset related impacts, additional impacts are scored for each project/program as summarized in Table 5.3-2.

Table 5.3-2: Impact scores for other project activities

Objective	Activity	Impact Score
Safety	Delta to wye conversion	10
Safety	Improved clearances	6
Environment	Oil containment close to a waterway	10
Efficiency	Substation decommissioning	10
Efficiency	Voltage upgrade	6

The end result is a single numerical score for each project/program that is used for ranking and prioritization. Table 5.3-3 presents the prioritized list of projects/programs over the forecast period.

Table 5.3-3: Prioritized list of projects/programs over the forecast period

Rank	Project/Program	Numeric Score
1	Iroquois Falls 2.4 kV to 12kV Upgrade - Destroyes Sub - Downtown & Millgate Sub	343
2	Cochrane New MTS	235
3	Kapuskasing 4.15kV to 25kV Conversion	215
4	Cochrane Feeder Fortification	200
5	Cochrane Line & Transformer	178
6	Pole Replacements – Iroquois Falls	136
7	Pole Replacements – Cochrane	136
8	Pole Replacements – Kapuskasing	136

Annual budget figures are drafted based on the analysis of the impact of planned capital expenditures on customer bills. Projects/programs are then selected in order of priority and scoped to fit within budget envelopes. In particular, annual scopes of multi-year projects are selected to align with budget envelopes and scaled back where necessary to ease rate impacts.

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

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

5.3.1.4 Data

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).

Main Data Sets

NOW Inc. uses a range of datasets to help inform its asset management inputs and process.
The following are some of the main data sets that NOW Inc. utilize:

- Asset registers, station single line diagrams and operating maps, indicating line lengths, conductor type and sizes, equipment ratings, and service age of assets.
- Asset Condition Analysis by asset class. This includes identification of assets that are in very poor and poor condition, which are more closely inspected to determine the level of current risk to NOW Inc.
- Station peak loading data, indicating equipment capacities and maximum load.
- Equipment inspection data sets, indicating operating condition of distribution system assets, and substation test result data sets.
- Outage information by cause code. This enables NOW Inc. to identify any specific assets/locations that are causing these outages, which in turn allows for more targeted investments.

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.

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

NOW Inc. serves three separate urban areas in northeastern Ontario, including the towns of Cochrane, Iroquois Falls, and Kapuskasing. These areas, like many in northeastern Ontario, are currently experiencing slow economic growth. NOW Inc.'s distribution system is predominantly overhead. The climate is typical of most towns in northern Ontario, with about 5500 to 8000 heating degree days per year and reaching temperature extremes of -40°C during winter. The presence of a number of different soil types, the

Canadian Shield, numerous clays, and muskeg make all excavation activities a challenge. The region is vulnerable to strong windstorms, which are a common occurrence.

5.3.2.1.2 Customers Served

In 2023, NOW Inc. served 5,961 electricity distribution customers across its service area. The table below presents NOW Inc.'s customer base over the historical period, divided into residential, general service less than 50 kW, and general service greater or equal to 50 kW. The table does not include USL, sentinel, and streetlight counts.

Table 5.3-1: Changing Trends in Customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2023	5,181	710	70	5,961
2022	5,159	715	67	5,941
2021	5,158	709	67	5,934
2020	5,150	706	73	5,929
2019	5,165	742	70	5,977
2018	5,127	724	68	5,919
2017	5,194	733	53	5,980

5.3.2.1.3 System Demand & Efficiency

The table below shows the annual peak demand (kW) for NOW Inc.'s distribution system.

Table 5.3-2: Peak System Demand Statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2023	22,129	20,464	19,874
2022	23,217	18,600	19,252
2021	22,199	20,235	19,341
2020	21,659	19,688	19,245
2019	23,352	18,301	19,047
2018	23,485	18,711	19,431
2017	23,708	21,210	19,318

The total NOW Inc. system has remained stable in size and has been consistently winter peaking. Peak data shown includes the net effect of embedded loads and generators. Variances in the seasonal peaks are attributable to weather temperature in both winter and summer and loading impacts associated with the number of degree days.

As illustrated in Table 5.3-3, NOW Inc.'s system losses have been fairly consistent in the last three years, with an average of 4.5%, increasing slightly when compared to the 2017-2021 period. NOW Inc.'s voltage conversion programs will help contribute to reducing system losses, ensuring they stay within acceptable ranges.

Table 5.3-3: Efficiency of kWh Purchased by NOW Inc.

Annual Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2023	113,302,381.8	118,537,962.0	4.4%
2022	115,031,517.0	120,436,452.0	4.5%
2021	114,189,855.0	119,387,030.0	4.4%
2020	115,003,539.0	119,627,905.0	3.9%
2019	117,455,380.0	121,853,180.0	3.6%
2018	117,028,006.0	121,885,758.0	4.0%
2017	115,940,780.0	120,844,247.0	4.1%

5.3.2.1.4 Summary of System Configuration

NOW Inc. uses four primary voltage levels to distribute power. There is one 2.4 kV delta overhead circuit, which serves a portion of the Town of Iroquois Falls. A 4.16/2.4 kV system is present all three Towns and is mostly overhead, with 1.18 km of underground cable. There are two 12.5/7.2 kV overhead circuits, which also serve the Town of Iroquois Falls. Finally, a 25/14.4 kV system operates in both the Town of Cochrane and the Town of Kapuskasing and is mostly overhead, with 2 km of underground cable. Table 5.3-4 summarizes the number of circuits and lengths of overhead conductors and underground cables for each voltage level.

Table 5.3-4: Overview of NOW Inc.'s circuit configuration

Voltage Level	Number of Circuits	Underground Cable Length (km)	Overhead Conductor Length (km)	Total Circuit Length (km)
2.4 kV Delta	1	0	10	10
4.16/2.4 kV	6	1.18	124.2	125.38
12.5/7.2 kV	2	0	72	72
25/14.4 kV	3	2	160.5	162.5
Total	**12**	**3.18**	**366.7**	**369.88**

NOW Inc. owns six DS: two in Cochrane (115-25/14.4 kV and 115-4.16/2.4 kV), three in Iroquois Falls (two 12.5/7.2-4.16/2.4 kV and one 12.5/7.2-2.4 kV delta), and one in Kapuskasing (25/14.4-4.16/2.4 kV). The Cochrane 115-25/14.4 kV DS is two transformers paralleled, while the Cochrane 115-4.16/2.4 kV DS is two transformer banks paralleled. Table 5.3-5 lists the vintage, voltage, nominal capacity, and number of feeders for each substation transformer.

Table 5.3-5: Overview of NOW Inc.'s Distribution Station Transformers

Name	Vintage	High Side Voltage (kV)	Low Side Voltage (kV)	Capacity (MVA)	Number of Feeders
Cochrane 25 kV – T1	1975	115	25/14.4	7.5	2
Cochrane 25 kV – T2	1975	115	25/14.4	7.5	
Cochrane 4.16 kV – T1A	1953	115	4.16/2.4	1	2
Cochrane 4.16 kV – T1B	1953	115	4.16/2.4	1	
Cochrane 4.16 kV – T1C	1953	115	4.16/2.4	1	
Cochrane 4.16 kV – T2A	1960	115	4.16/2.4	1	
Cochrane 4.16 kV – T2B	1959	115	4.16/2.4	1	
Cochrane 4.16 kV – T2C	1957	115	4.16/2.4	1	
Iroquois Falls – Cambridge	1975	12.5/7.2	4.16/2.4	2	1
Iroquois Falls – Mill Gate	1955	12.5/7.2	2.4 Delta	2	1
Iroquois Falls – Detroyes	1966	12.5/7.2	4.16/2.4	4	2
Kapuskasing	1963	25/14.4	4.16/2.4	5	1

5.3.2.1.5 Climate

The majority of NOW Inc.'s distribution network is above ground. The weather in these towns is typical for northern Ontario, experiencing 5,500 to 8,000 heating degree days annually, with winter temperatures plummeting to as low as -40°C. The area's diverse terrain, featuring the Canadian Shield, various clays, and muskeg, presents significant challenges for any digging work. Additionally, the region frequently encounters strong windstorms, making it susceptible to weather-related disturbances.

5.3.2.1.6 Economic Growth

NOW Inc. serves three separate urban areas in northeastern Ontario, including the towns of Cochrane, Iroquois Falls, and Kapuskasing. These areas, like many in northeastern Ontario, are currently experiencing slow economic growth, and are forecast to see slow economic growth.

5.3.2.2 Asset Information

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

5.3.2.2.1 Asset Capacity & Utilization

Table 5.3-6 below outlines the historical loading and forecasting load for each of NOW Inc.'s current substations.

Table 5.3-6: Load Forecast for NOW Inc.'s Substations

Transformer Station	Rated Capacity MVA	Additional Available Capacity (MVA)	Historical Peak Loading (MW)						Forecast Peak Loading (MW)			
			2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Cochrane MTS 115 - 25 kV	20	None	9.5	9.3	9.5	9.7	10.0	9.2	10.1	10.1	10.1	10.1
Cochrane West MTS (115 - 5 kV)	6	None	1.8	2.2	2	1.9	2.1	2	2	2	2	2
Iroquois Falls DS	8	None	1.8	1.8	1.6	2.4	2.4	2.5	2.5	2.5	2.5	2.5
Kapuskasing TS	5	None	7.8	7.7	6.7	6.8	7.4	7.4	7.4	7.4	7.4	7.4

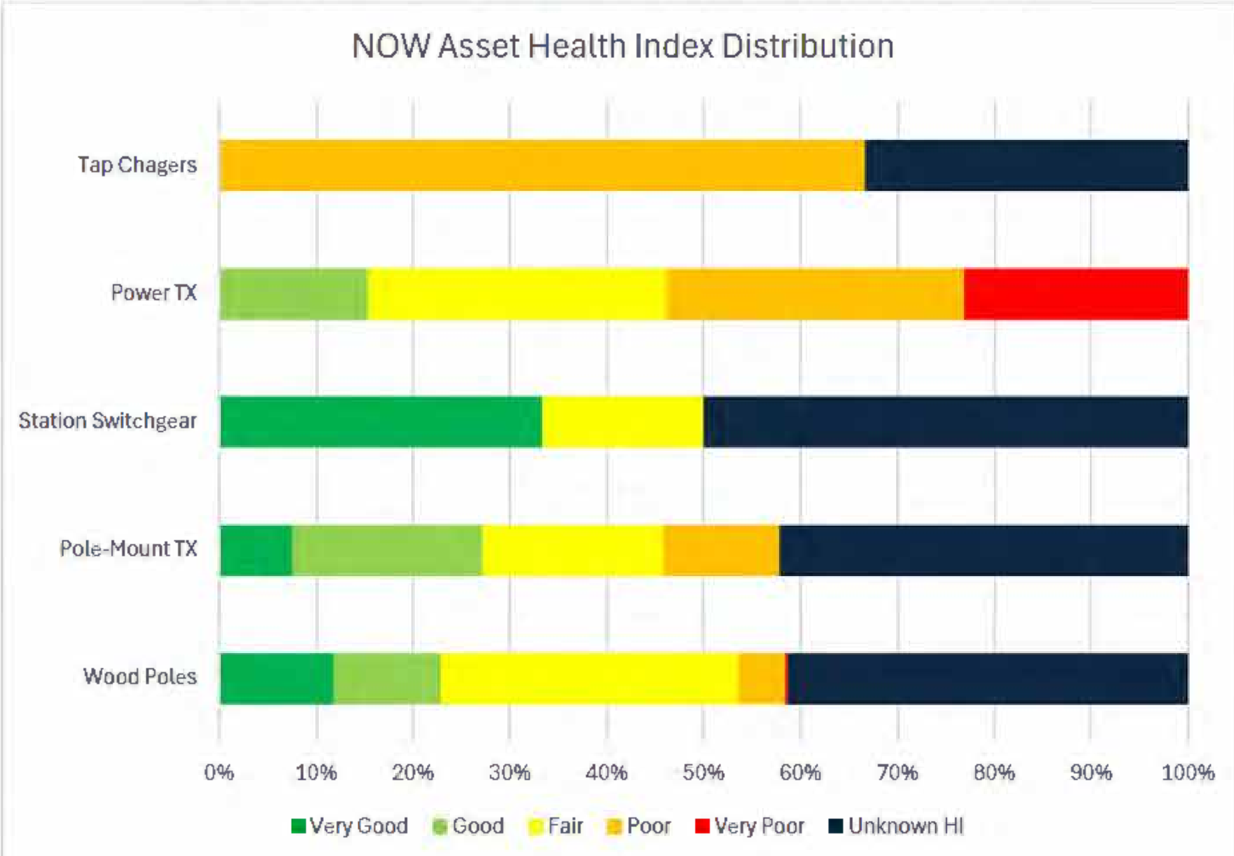
NOW Inc. provided its load forecast data to the IESO for system planning purposes stating the summer and winter demand for the Cochrane TS. This load forecast took a conservative approach indicating a 0% annual load growth over a 10-year period. Near term and projected summer peak demand was 10.2 MW and winter was 11.8 MW. Using a system power factor of 0.9, the estimated summer peak demand in MVA is 11.3 MVA and winter peak demand is 13.1 MVA.

Major contributions to increases to summer peak demand are the adoption of air conditioning as average and peak daily temperatures increase and the influence of decarbonizing transportation through adoption of EVs or the more practical application for northern climates plug in electric hybrids (PHEVs). Extreme temperatures are also critical factors contributing to peak events.

5.3.2.2.2 Asset Condition & Asset Demographics

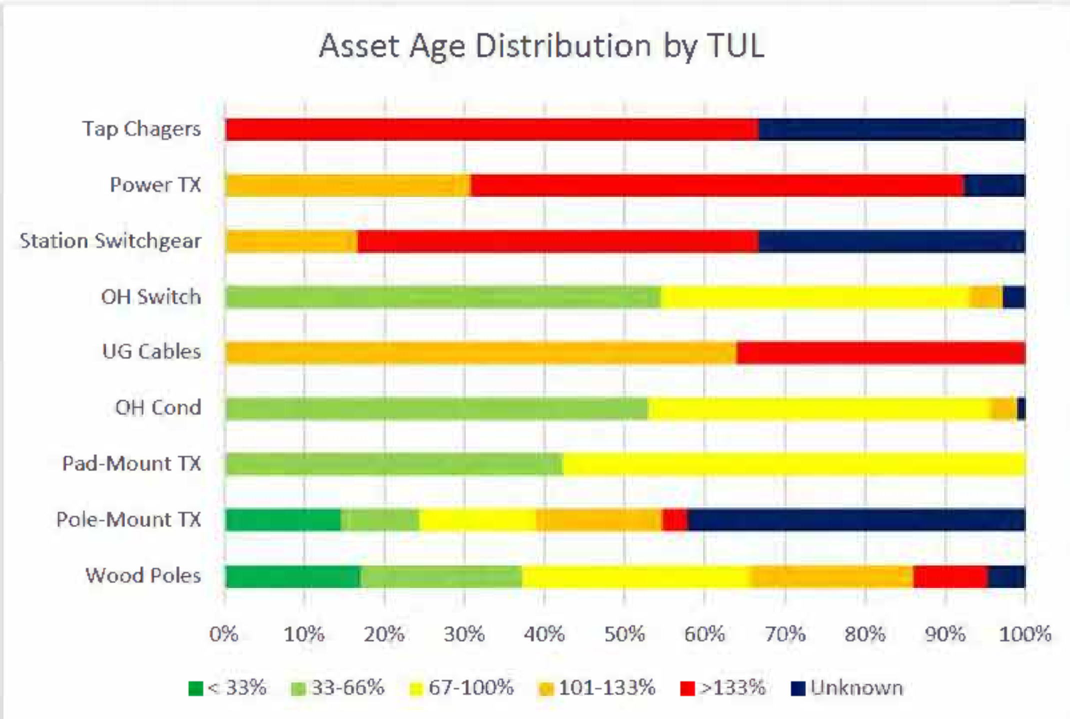
The ACA study was carried out by engaging BBA Inc. in 2024 for NOW Inc. to establish the health and condition of its distribution assets in-service. Figure 5.3-4 presents a summary of the asset health index results from the ACA while Figure 5.3-5 presents a summary of asset age distribution by their Typical Useful Life (TUL).

Figure 5.3-4: NOW Inc.'s Health Index Asset Distribution



As shown in the figure above, 41% or four out of the five sub-categories have invalid health indices due to insufficient data for a valid health index calculation. Specifically, 11% of the assets are in "very good" condition, 12% are in "good" condition, 29% are in "fair" condition, and 6% are in "poor" condition. No assets were classified as being in "very poor" condition.

Figure 5.3-5: NOW Inc.'s Asset Age Distribution by TUL



The above figure describes the age of each of the eight asset classes relative to their individual TUL. It is observed that about 70% of the assets are either below or about to cross their TUL while 22% of the assets are beyond their TUL. Due to insufficient information available, these results are unknown for 8% of the assets.

The 2024 ACA report is found in Appendix D and contains detailed results for each asset class including demographics. Subsequently, Appendices D-1 through D-8 provide substation maintenance reports, visual inspection reports, oil analysis data, and transformer fleet assessment reports.

5.3.2.2.3 Asset Risks

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

Asset risks are considered as part of NOW Inc.'s prioritization process and are ultimately used to determine the prioritized list of capital projects and programs over the forecast period. Additional information on this process can be found in section 5.3.1.3 and NOW Inc.'s list of prioritized projects for the test year is included in section 5.4.2.1.

5.3.2.3 Transmission or High Voltage Assets

There should also be a statement as to whether the distributor has had any transmission or high voltage assets (> 50kV) deemed previously by the OEB as distribution assets, and whether there are any such assets that the distributor is asking the OEB to deem as distribution assets in the present application.

NOW Inc. does not have any transmission or high voltage 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).

NOW Inc. is an embedded distributor.

5.3.3 Asset Lifecycle Optimization Policies and Practices

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. The information provided should be sufficient to show the trade-off between spending on new capital (i.e., replacement) and life-extending refurbishment.

The intent of NOW Inc.'s maintenance programs is to provide base knowledge to make informed decisions and identify any future upgrades. The data collected also provides valuable information upon which to base repair work, refurbishment activities, and asset replacement schedules. NOW Inc.'s asset replacement and refurbishment policies for each class of assets is summarized below.

Substations

Testing of substation transformer oil is a very good predictor of when a transformer is reaching the end of its life. NOW Inc. retains a third-party consultant to perform Dissolved Gas Analysis ("DGA") on its substation transformers, tap changers, and regulators. NOW Inc. accounts for the recommendations of the third-party consultant – whether to continue re-testing, schedule shut-downs for investigation, or plan for replacement – when making replacement or refurbishment decisions for substation transformers and tap changers. When weighing the consultant's recommendations, NOW Inc. considers the impact on its distribution weights.

Annual oil testing allows time to make decisions about replacement and capital investment is therefore based on a proactive approach. Maintaining substations over the long term adds system O&M costs, which would not be present if the stations were eliminated. In addition, as part of its substation regular maintenance the following testing carried out on a 3-year rotation:

Substation Transformers

- Overall PF & CAP
- Exciting Current
- Leakage Reactance H-X
- TTR H-X
- DC Winding Resistance H
- DC Winding Resistance X
- Insulation Resistance

Substation Switchgear

- Switchgear Bus Resistance Testing

Distribution Transformers

The majority of NOW Inc.'s distribution transformers are pole-mounted, with only a few pad-mounted transformers. All distribution transformers are inspected and monitored regularly and replaced on a reactive basis. Failed transformers are replaced in order to restore power. Small deficiencies are repaired during inspections or scheduled for a follow-up repair, but more severe deterioration necessitates replacement. Pole-mounted transformers with cracked bushing or evidence of oil leaks, for example, are considered for replacement. Pad-mount transformers may be replaced due to severe rusting on the tank or frame, cracked bushings, or evidence of oil leaks. Life extension techniques for distribution transformers are limited. NOW Inc. does not implement life extension programs for distribution transformers outside of its regular three-year inspection cycle. This helps keep system O&M costs low. System renewal budgets account for reactive replacements of transformers, as needed.

Poles

NOW Inc.'s overhead lines are all supported by wood poles. Poles are regularly inspected, and corrective action is taken as needed on flagged issues. Pole replacements are budgeted each year and the inspection process identifies individual poles for replacement. NOW Inc. does not see value in the testing or maintenance of poles.

Distribution Switches

The major switching assets on NOW Inc.'s distribution system are overhead gang-operated switches and pad-mounted switchgear. This is a small group of assets, with only five gang-operated switches and five pad-mounted switchgear in NOW Inc.'s service territory. Distribution switches are inspected, maintained, and monitored regularly. Regular maintenance adds to system O&M costs, but extends the life of the switches to reduce system renewal spending. Switches which have deteriorated beyond maintenance capabilities are replaced.

Cables / Conductors

Underground cables make up less than 1% of NOW Inc.'s distribution system, yet underground cables require particular attention during inspection and maintenance as they are prone to insulation failure. NOW Inc. has a mixture of direct-buried and duct-embedded cables. NOW Inc.'s inspection program covers terminations of cable only, which are exposed in pad-mounted equipment and riser poles. Underground cables are monitored for failure and replaced when a failure occurs. Direct-buried cables are replaced with duct structures, which will decrease the cost of future replacements. NOW Inc. has not seen the need for proactive maintenance of cables or cable injection.

The remaining 99% of NOW Inc.'s distribution system is comprised of overhead conductors. Overhead conductors typically outlive the poles that carry them and are replaced when the pole line is rebuilt; however, NOW Inc. has some older #6 copper conductors in its system, which is more prone to breaking. Overhead conductors are inspected on a three-year cycle to manage this risk. During line patrols, conductors are assessed for signs of corrosion, broken strands, abrasions, annealing, and elongation. There are no maintenance programs for overhead conductors.

5.3.3.2 Description of Maintenance and Inspection Practices

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

NOW Inc.'s maintenance and inspection programs have been carefully selected and are carried out such that present service levels will continue to be maintained to balance customer needs, price/reliability trade-offs, and industry best practices. It is assumed that service levels will not be changed significantly due to the introduction of new regulatory requirements. Assumptions regarding TUL are based on Kinectrics' Asset Depreciation Study for the Ontario Energy Board. NOW Inc. adopts the following maintenance planning criteria and assumptions:

- The TUL of substation transformer is 45 years.
- The 4.16/2.4 kV distribution plant in Kapuskasing and the 2.4 kV delta system in Iroquois Falls are of a similar age or older than the substation transformers also have a TUL of 45 years.
- A pole failure can be a significant risk as the result could injure the public and/or cause a lengthy interruption.
- As distribution plant is replaced, it is built to 12.5/7.2 kV in Iroquois Falls and 25/14.4 kV in Kapuskasing, which replaces older poles.
- Eliminating stations does not generally require line extensions as the existing path or pole line is already in place.
- The TUL of pole-mounted and pad-mounted transformers is 40 years, and their outage impact is limited to a small number of customers for a short duration.
- The TUL of gang-operated overhead switches is 60 years and their risk of failure is low.

- The TUL of pad-mounted switchgear is 35 years and the impact of a switchgear failure is a significant risk; wherein a customer outage would likely occur and the safety of the public and staff would be impacted.
- The TUL of XLPE cable is 25 to 35 years and the impact of cable failure is low risk and public safety is not likely to be impacted as cables are buried and not exposed.

The inspection and maintenance of distribution assets involves substation inspections, line patrol records, and underground inspections. Maintenance standards are built upon manufacturer's recommendations, industry and regulatory requirements, and industry best practices. NOW Inc.'s
inspection and maintenance programs are continually being improved.

NOW Inc.'s inspection and maintenance programs for each asset are summarized in Table 5.3-4. Inspection cycles are based on the Minimum Inspection Requirements.

Table 5.3-4: Summary of Inspection and Maintenance Programs for each asset

Asset	Inspection Programs	Maintenance Program
Substations	• Monthly substation inspection • Annual oil analysis for substation transformers, tap changers, and regulators • Thermal Imaging	• Regular maintenance (vegetation control, switch-gear maintenance, battery bank maintenance, snow removal)
Pole-mounted transformers	• Inspected every three years • Thermal Imaging	• None
Pad-mounted transformers	• Inspected every three years • Thermal Imaging	• Some maintenance as required (vegetation control, connection cleaning and tightening)
Poles	• Inspected every three years • Thermal Imaging	• None
Gang-operated switches	• Inspected every three years • Thermal Imaging	• Regular maintenance (adjustments as required)
Pad-mounted switchgear	• Inspected every three years • Thermal Imaging	• Regular maintenance (cleaning and adjusting)
Underground cables	• Terminations inspected every three years (at pad-mounted equipment and riser poles)	• None
Overhead conductors	• Inspected every three years • Thermal Imaging	• None

Substations are inspected once per month to check the visual condition of the substation equipment, as well as the building, fence, locks, and signs. Transformer and regulator oil temperature, liquid temperature, and pressure gauges are read. The insulators on transformers and regulators are inspected for contamination or cracks; oil tanks are inspected for leaks. The arrestors and tap totalizers on the transformers are also checked.

Phase currents are read, and fuses are checked on both sides of the transformers; secondary voltages are read from the metering equipment. Lights, housekeeping, batteries, personal protective equipment, and fire extinguishers are all checked in switch rooms. In addition to the monthly inspections, annual oil testing for substation transformers, tap changers, and regulators is employed for condition assessment purposes.

Line patrols are performed on a three-year cycle. Pole-mounted transformers are inspected for signs of corrosion or oil leaks; transformer bushings are checked for cracks or contamination. Wood poles are checked for insect infestation or woodpecker damage; crossarms, pole tops, and pole shells are assessed for deterioration; leaning poles are noted. Insulators on the poles are checked for chips, cracks, and contamination. Gang-operated switches are inspected for corrosion or mechanical deterioration and are maintained regularly. Finally, overhead lines are checked for signs of corrosion, broken strands, abrasions, annealing, and elongation. Line patrol inspection results are not formally documented. Instead, line staff note any deficiencies during line patrols or trouble calls for immediate or scheduled replacement depending on the severity of the damage or deterioration.

NOW Inc.'s underground inspection program covers pad-mounted equipment and underground cable terminations. Pad-mounted transformers require very little maintenance and are inspected for signs of corrosion or oil leaks; transformer bushings are checked for cracks or contamination. Pad-mounted switchgear are inspected for corrosion or mechanical deterioration and are maintained regularly. Underground cable terminations, which are exposed in pad-mounted equipment and riser poles, are inspected for signs of moisture ingress.

Beginning in 2024, NOW Inc. began collecting infrared data as part of its efforts to enhance asset management. This data collection marks a significant step in improving the monitoring and maintenance of assets. The infrared information is now being systematically documented and integrated into the asset management system. This formal documentation process ensures that the infrared data is effectively utilized for asset evaluation, facilitating better decision-making and proactive maintenance strategies. The integration of this data into the asset management system will provide a comprehensive overview of asset conditions, improve the accuracy of performance assessments, and support more informed planning and management.

Tree trimming is performed to reduce the frequency of distribution system outages and momentary interruptions. Currently, NOW Inc. has struggled to maintain its tree trimming schedule and is transitioning to utilizing third-party services to manage the vegetation program. The third-party provider will systematically cover NOW Inc.'s territory each year to trim trees that are, or could potentially be, in conflict with the distribution system. Other indications that a tree may need to be trimmed are:

a. reports of electrical outages caused by trees;
b. areas where trees have been damaged by storms;
c. periodic inspections by NOW Inc. personnel; and
d. reports from customers indicating potential tree problems.

NOW Inc. has an established reporting mechanism for tree trimming for the general public.

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.

The inputs and processes for forecasting, prioritizing, and optimizing System Renewal spending are summarized in the following sub-sections. Additional information can be found in sections 5.3.1.2 and 5.3.1.3 of this DSP.

5.3.3.3.1 Forecasting

System Renewal projects are typically discretionary. The only exception in NOW Inc.'s case are the meter projects with mandated service obligations through Measurement Canada. 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 BBA Inc. to establish the health and condition of distribution and substation assets in service. By considering all relevant information related to the assets' operating condition, the condition of all infrastructure assets was assessed and expressed on a normalized index in the form of a HI. The HI was related to the probability of failure values for each project, using a weighted average approach, as described in detail in Appendix D, 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 NOW Inc.'s assets over the forecast period. For metering projects, a combination of age, meter inspection and testing are used to forecast the meter replacements.

5.3.3.3.2 Prioritization & Optimization

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.

NOW Inc.'s optimization and prioritization process is described in section 5.3.1.3.

5.3.3.3.3 Strategies for Operating within Budget Envelopes

The forecasted System Renewal projects were selected to uphold system dependability, timing their rollout according to available asset renewal funding and the manpower needed for the predominantly required work. Priority for renewal or rehabilitation within the next five years is given to assets that, if failed, would have the most severe consequences.

NOW Inc. regularly refines its planning process with the latest data, undertaking annual investment planning to guide any needed budget adjustments for the subsequent year. Aware that situations evolve, NOW Inc. remains flexible, ready to adjust budgets based on the shifting needs of customers and the system. For instance, System Access projects, due to their essential nature, will be prioritized over System Renewal projects in case of conflicting requirements. This annual investment planning ensures that NOW Inc. can effectively allocate resources to the most critical projects and programs throughout the forecast period, all while adhering to the set budget limits. Additionally, NOW Inc. keeps a close watch on project implementation relative to budgets, making necessary adjustments to remain within the overall financial plan.

5.3.3.3.4 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

Risk assessment is integral to selecting and ranking capital investments during the prioritization stage, ultimately shaping the list of capital projects and programs for the forecast period. It is at this juncture that NOW Inc. evaluates the risks of both proceeding and not proceeding with a particular capital investment, deciding if it is necessary within the forecast period or if postponement is feasible.

Assets that exhibit intolerably high-risk levels are subjected to meticulous monitoring, with plans developed within the project scope for maintenance, refurbishment, or replacement to mitigate the risk to a manageable level. It is important to recognize that certain assets are inherently riskier than others. The most critical projects within each category are pinpointed during the prioritization phase and undergo additional examination and expert assessment to rectify data inconsistencies and define the proper scope 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.

NOW Inc. has continued to follow its previous maintenance and inspection programs, with some enhancements incorporated. Mainly, the substation regular maintenance would now include 3-year rotation in testing below and all inspections would include thermal imaging within their inspection's cycles.

Substation Transformers

- Overall PF & CAP
- Exciting Current
- Leakage Reactance H-X
- TTR H-X
- DC Winding Resistance H
- DC Winding Resistance X
- Insulation Resistance

Substation Switchgear

- Switchgear Bus Resistance Testing

5.3.4 System Capability Assessment for REG & DERs

<<Note: If the distributor has no forecast costs to accommodate and connect REG facilities, state this and delete subsections 5.3.4(a) – 5.3.4 (e)>>

A distributor should provide a list of restricted feeders by name, the feeder designation, the reason for the restriction, and number of connected customers, and explain if there are plans to improve their distribution system's ability to connect distributed energy resources.

If a distributor has incurred or expects to incur costs to accommodate and connect renewable generation facilities (e.g., connection assets, expansions and/or renewable enabling improvements, etc.) 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 provide the following:

NOW Inc. does not have any forecast cost to accommodate and connect REG facilities during the forecast period.

5.3.5 CDM Activities to Address System Needs

The OEB's 2021 Conservation and Demand Management Guidelines for Electricity Distributors (the CDM Guidelines) provide updated OEB guidance on the role of conservation and demand management (CDM) for rate-regulated electricity distributors, taking into account the provincial 2021-2024 CDM Framework and previous provincial CDM frameworks and addressing the treatment of CDM activities in distribution rates. The CDM Guidelines require distributors to make reasonable efforts to incorporate 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. CDM activities potentially eligible for distribution rate funding are not limited to energy efficiency programs and include activities that reduce instantaneous electricity demand, including demand response and energy storage.

A distributor's DSP should describe how it has taken CDM into consideration in its planning process. The degree of consideration of CDM in meeting system needs should be proportional to the expected benefits, and will likely vary across distributors, taking into account the size and resources of a distributor. CDM will not be a viable alternative for all types of traditional infrastructure investments. Distributors are encouraged to take account of learnings from CDM activities that have been undertaken by other electricity distributors, in Ontario or elsewhere.

Distributors may apply to the OEB for funding through distribution rates for CDM activities as specified in the CDM Guidelines. Any application for CDM funding to address system needs must include a consideration of the projected effects on 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, including providing details on the system need that is being addressed, any infrastructure investments that are being avoided or deferred as a result of the CDM activity (could include investments upstream of a distributor), and the prioritization of the proposed CDM activity relative to other system investments in the DSP.

Distributors should describe their approach to assessing the benefits and costs of CDM activity. However, the CDM Guidelines recognized that the Framework for Energy Innovation's (FEI) near-term activities include defining an approach to assessing the benefits and costs of distributed energy resources and may apply approaches from the FEI in the future.

2021 CDM Guidelines:
A distributor should explain the proposed CDM activity in the context of the DSP, including providing details on the system need that is being addressed, any infrastructure investments that are being avoided or deferred as a result of the CDM activity, and the prioritization of the proposed CDM activity relative to other system investments in the DSP.

A distributor should also provide evidence as to why the proposed CDM activity is the preferred approach (alone or in combination with an infrastructure solution) to meeting a system need, including an assessment of the projected benefits to customers relative to cost impacts.

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

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

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

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

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

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.

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- Capital Projects Table and 2-AB – Capital Expenditure Summary Table along with the following information about a distributor's capital expenditures:

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

Category	Historical											
	2017			2018			2019			2020		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Bgt.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access												
Gross Capital Spend	15	2	-88%	15	13	-14%	20	2	-91%	20	31	53%
Capital Contributions												
Net Capital Expenditures	15	2	-88%	15	13	-14%	20	2	-91%	20	31	53%
System Renewal												
Gross Capital Spend	330	263	-20%	395	242	-39%	370	235	-37%	350	217	-38%
Capital Contributions		8										
Net Capital Expenditures	330	254	-23%	395	242	-39%	370	235	-37%	350	217	-38%
System Service												
Gross Capital Spend	290	427	47%	355	487	37%	370	361	-3%	385	395	3%
Capital Contributions												
Net Capital Expenditures	290	427	47%	355	487	37%	370	361	-3%	385	395	3%
General Plant												
Gross Capital Spend	143	153	8%	33	140	331%	33	77	137%	33	193	495%
Capital Contributions												
Net Capital Expenditures	143	153	8%	33	140	331%	33	77	137%	33	193	495%
Total Expenditure, Gross	**778**	**845**	**9%**	**798**	**881**	**10%**	**793**	**674**	**-15%**	**788**	**837**	**6%**
Total Capital Contribution		**8**										
Total Expenditure, Net	**778**	**836**	**8%**	**798**	**881**	**10%**	**793**	**674**	**-15%**	**788**	**837**	**6%**
System O&M	1,383	1,230	-11%	1,404	1,379	-2%	1,402	1,416	1%	1,392	1,492	7%

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

Category	Historical									Bridge Year		
	2021			2022			2023			2024		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Bgt.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access												
Gross Capital Spend	20	44	120%	-	6	-	-	35	-			
Capital Contributions												
Net Capital Expenditures	20	44	120%	-	6	-	-	35	-			
System Renewal												
Gross Capital Spend	380	434	14%	500	285	-43%	360	349	-3%	90		
Capital Contributions	-	-	-	-	-	-	-	-	-	-		
Net Capital Expenditures	380	434	14%	500	285	-43%	360	349	-3%	90		
System Service												
Gross Capital Spend	400	341	-15%	400	282	-29%	380	61	-84%	456		
Capital Contributions	-	-	-	-	-	-	-	-	-	-		
Net Capital Expenditures	400	341	-15%	400	282	-29%	380	61	-84%	456		
General Plant												
Gross Capital Spend	33	39	20%	120	373	211%	302	282	-7%	1,327		
Capital Contributions	-	-	-	-	-	-	-	-	-	-		
Net Capital Expenditures	33	39	20%	120	373	211%	302	282	-7%	1,327		
Total Expenditure, Gross	**833**	**859**	**3%**	**1,020**	**947**	**-7%**	**1,042**	**727**	**-30%**	**1,873**	**0**	**-100%**
Total Capital Contribution												
Total Expenditure, Net	**833**	**859**	**3%**	**1,020**	**947**	**-7%**	**1,042**	**727**	**-30%**	**1,873**	**0**	**-100%**
System O&M	1,416	1,466	4%	1,449	1,662	15%	1,566	1,769	13%	1,981		

Table 5.4-2: Forecast Capital Expenditures (including New Cochrane MS) and System O&M

Category	Forecast				
	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access					
Gross Capital Spend	15	15	15	15	15
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	15	15	15	15	15
System Renewal					
Gross Capital Spend	50	50	671	50	50
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	50	50	671	50	50
System Service					
Gross Capital Spend	6,785	4,233	5,007	3,861	1,090
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	6,785	4,233	5,007	3,861	1,090
General Plant					
Gross Capital Spend	64	706	64	64	646
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	64	706	64	64	646
Total Expenditure, Gross	**6,914**	**5,004**	**5,757**	**3,990**	**1,801**
Total Capital Contribution	**-**	**-**	**-**	**-**	**-**
Total Expenditure, Net	**6,914**	**5,004**	**5,757**	**3,990**	**1,801**
System O&M	2,578	2,668	2,748	2,830	2,915

Table 5.4-3: Forecast Capital Expenditures (excluding New Cochrane MS) and System O&M

Category	Forecast				
	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access					
Gross Capital Spend	15	15	15	15	15
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	15	15	15	15	15
System Renewal					
Gross Capital Spend	50	50	671	50	50
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	50	50	671	50	50
System Service					
Gross Capital Spend	1,698	1,000	1,227	1,575	1,090
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	1,698	1,000	1,227	1,575	1,090
General Plant					
Gross Capital Spend	64	706	64	64	646
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	64	706	64	64	646
Total Expenditure, Gross	**1,827**	**1,771**	**1,977**	**1,704**	**1,801**
Total Capital Contribution	**-**	**-**	**-**	**-**	**-**
Total Expenditure, Net	**1,827**	**1,771**	**1,977**	**1,704**	**1,801**
System O&M	2,578	2,668	2,748	2,830	2,915

5.4.1.1 Plan vs Actual Variances for the Historical Period

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 that $50,000, 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.

Table 5.4-4: Variance Explanations - 2017 Planned Versus Actuals

Category	2017			Variance Explanations
	Plan.	Act.	Var.	
	$ '000			
System Access, Net	15	2	-13	Below Materiality Threshold
System Renewal, Net	330	263	-67	Due to the need to increase spending on the planned voltage conversion, NOW Inc. reduced its pole changes spend to prioritize the voltage conversion as it is a higher priority project.
System Service, Net	290	427	137	Voltage conversion projects were prioritized over system renewal pole changes. The cost increases due to material costs.
General Plant, Net	143	153	11	Below Materiality Threshold
Total Expenditure, Net	778	836	58	Please see explanations above.
Capital Contributions		8	8	Below Materiality Threshold
Total Expenditure, Gross	778	845	67	Please see explanations above.

Table 5.4-5: Variance Explanations - 2018 Planned Versus Actuals

Category	2018			Variance Explanations
	Plan.	Act.	Var.	
	$ '000			
System Access, Net	15	13	-2	Below Materiality Threshold
System Renewal, Net	395	242	-153	Due to the need to increase spending on the planned voltage conversion, NOW Inc. reduced its pole changes spend to prioritize the voltage conversion as it is a higher priority project.
System Service, Net	355	487	132	Voltage conversion projects were prioritized over system renewal pole changes. The cost increases due to material costs
General Plant, Net	33	140	107	NOW Inc. had not originally budgeted for spare parts in inventory change. In addition, due to the need to replace some major vehicle components, NOW Inc. increased its vehicle expenditure.
Total Expenditure, Net	798	881	83	Please see explanations above.
Capital Contributions	-	-	-	N/A
Total Expenditure, Gross	798	881	83	Please see explanations above.

Table 5.4-6: Variance Explanations - 2019 Planned Versus Actuals

Category	2019 Plan. ($ '000)	2019 Act. ($ '000)	2019 Var. ($ '000)	Variance Explanations
System Access, Net	20	2	-18	Below Materiality Threshold
System Renewal, Net	370	235	-135	NOW Inc. identified less poles that required to be replaced than originally forecast, so reduced its actual spending accordingly.
System Service, Net	370	361	-9	Below Materiality Threshold
General Plant, Net	33	77	44	Below Materiality Threshold
Total Expenditure, Net	793	674	-119	Please see explanations above.
Capital Contributions	-	-	-	N/A
Total Expenditure, Gross	793	674	-119	Please see explanations above.

Table 5.4-7: Variance Explanations - 2020 Planned Versus Actuals

Category	2020 Plan. ($ '000)	2020 Act. ($ '000)	2020 Var. ($ '000)	Variance Explanations
System Access, Net	20	31	11	Below Materiality Threshold
System Renewal, Net	350	217	-133	The planned Station DS replacement did not go ahead as planned.
System Service, Net	385	395	10	Below Materiality Threshold
General Plant, Net	33	193	160	NOW Inc. had not originally budgeted for spare parts in inventory change. In addition, due to the need to replace some major vehicle components, NOW Inc. increased its vehicle expenditure.
Total Expenditure, Net	788	837	49	Below Materiality Threshold
Capital Contributions	-	-	-	N/A
Total Expenditure, Gross	788	837	49	Below Materiality Threshold

Table 5.4-8: Variance Explanations - 2021 Planned Versus Budget

Category	2021 Plan. ($ '000)	2021 Act. ($ '000)	2021 Var. ($ '000)	Variance Explanations
System Access, Net	20	44	24	Below Materiality Threshold
System Renewal, Net	380	434	54	A slight increase in material costs due to the impacts of COVID-19 accounted for an overall increase in the System Renewal spending.
System Service, Net	400	341	-59	NOW Inc. experienced some resource staffing issues which resulted in less capital expenditure being carried out.
General Plant, Net	33	39	6	Below Materiality Threshold
Total Expenditure, Net	833	859	26	Below Materiality Threshold
Capital Contributions	-	-	-	N/A

Category	2021 Plan.	Act.	Var.	Variance Explanations
	$ '000			
Total Expenditure, Gross	833	859	26	Below Materiality Threshold

Table 5.4-9: Variance Explanations - 2022 Planned Versus Budget

Category	2022 Plan.	Act.	Var.	Variance Explanations
	$ '000			
System Access, Net	-	6	6	Below Materiality Threshold
System Renewal, Net	500	285	-215	System Renewal spending was reduced to accommodate the increases in General Plant spend
System Service, Net	400	282	-118	NOW Inc. experienced some resource staffing issues which resulted in less capital expenditure being carried out.
General Plant, Net	120	373	253	NOW Inc. had not originally budgeted for spare parts in inventory change. In addition, work was identified to be carried out on service centres as well as the purchase of a new folding machine.
Total Expenditure, Net	1,020	947	-73	Please see explanations above.
Capital Contributions	-	-	-	N/A
Total Expenditure, Gross	1,020	947	-73	Please see explanations above.

Table 5.4-10: Variance Explanations - 2023 Planned Versus Budget

Category	2023 Plan.	Act.	Var.	Variance Explanations
	$ '000			
System Access, Net	-	35	35	Below Materiality Threshold
System Renewal, Net	360	349	-11	Below Materiality Threshold
System Service, Net	380	61	-319	NOW Inc. experienced some resource staffing issues which resulted in less capital expenditure being carried out.
General Plant, Net	302	282	-20	Below Materiality Threshold
Total Expenditure, Net	1,042	727	-316	Please see explanations above.
Capital Contributions	-	-	-	N/A
Total Expenditure, Gross	1,042	727	-316	Please see explanations above.

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

5.4.1.2 Forecast Expenditures

An analysis of a distributor's capital expenditures for the DSP's forecast period.

5.4.1.2.1 System Access

Customer service requests and third-party infrastructure development projects are both driven by parties external to NOW Inc. Since there is no growth in NOW Inc.'s service territory and since the respective Towns have not planned any road widening projects over the forecast period, NOW Inc. has not budgeted any capital expenditures due to customer service requests and third-party infrastructure development. NOW Inc.'s system access budget only includes metering, based on the expected rate of failure of the existing smart meters and the resource constraint of dispersing the meter replacement over the five years of the forecast period.

Table 5.4-11: Forecast Net System Access Expenditures

Category	Forecast					Total	Percent of Total
	2025	2026	2027	2028	2029		
	$ '000						
Metering	15	15	15	15	15	75	100%
Total Expenditure, Net	**15**	**15**	**15**	**15**	**15**	**75**	**100%**

5.4.1.2.2 System Renewal

Expenditures within the System Renewal category is largely driven by the condition of distribution system assets and are driven by the overall reliability, safety, and sustainment of the distribution system. As outlined in Section 5.3.1, a key input into determining its system renewal projects is the inspection and ACA results. These results are a starting point for NOW Inc. to use to determine which investments are required over the DSP period.

Table 5.4-12: Forecast Net System Renewal Expenditures

Category	Forecast					Total	Percent of Total
	2025	2026	2027	2028	2029		
	$ '000						
Pole Changes - Cochrane	20	20	20	20	20	100	11%
Pole Changes - Kapuskasing	20	20	20	20	20	100	11%
Pole Changes - Iroquois Falls	10	10	10	10	10	50	6%
Cochrane Line & Transformers	-	-	621	-	-	621	71%
Total Expenditure, Net	**50**	**50**	**671**	**50**	**50**	**871**	**100%**

The system renewal programs are summarized below:

Cochrane Line & Transformers (71%)

This investment category includes the replacement of transformers that are or past their end of life and have been deemed in need of replacement due to being in poor or very poor condition and having a high risk of failure as identified through the ACA. This project will support feeder fortification and the new Cochrane TS project.

Pole Changes – Cochrane (11%); Pole Changes – Kapuskasing (11%); and Pole Changes – Iroquois Falls (6%)

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

5.4.1.2.3 System Service

System Service investments are modifications to NOW Inc.'s distribution system to ensure the distribution system continues to meet NOW Inc.'s operational objectives (system efficiency, DER integration, grid flexibility, etc.) while addressing anticipated future customer electricity service requirements. Investments in system service are captured in the following table. Tables below showcase system service expenditures including and excluding the new Cochrane MTS.

Table 5.4-13a: Forecast Net System Service Expenditures (including New Cochrane MS)

Category	Forecast					Total	Percent of Total
	2025	2026	2027	2028	2029		
	$ '000						
Kapuskasing - 5Kv to 25Kv Conv. Upgrade	627	1,000	-	-	-	1,627	8%
Iroquois Falls - 4 to 12 Kv Upgrade - Destroyes Sub - Downtown	-	-	1,227	1,090	1,090	3,407	16%
Iroquois Falls - 2.4 to 12 Kv Upgrade - Millgate Sub	1,071	-	-	-	-	1,071	5%
Cochrane Feeder Fortification	-	-	-	485	-	485	2%
Cochrane New MS	5,088	3,233	3,780	2,286	-	14,387	69%
Total Expenditure, Net	**6,785**	**4,233**	**5,007**	**3,861**	**1,090**	**20,977**	**100%**

Cochrane New MTS (69%)

This investment category is a major driver of increased spending in the System Service category which involves the construction of a new Cochrane Municipal Station to address the current capacity constraints and future load growth. The construction of a new Cochrane Municipal Station will deliver enhanced capacity to meet both current and future load demands. It will improve reliability and system flexibility, resulting in reduced maintenance costs. Additionally, it will support future electrification needs, such as increased demand for EVs. Building a new station also allows for the normal operation of the Cochrane distribution system until commissioning, minimizing required outage time. For more detail on this project, please refer to the material narrative in Appendix A. Furthermore, Appendices A-1 and A-2 provide consequences of inaction regarding 115 to 25kV and 115 kV to 4.16kV Systems; and the Feasibility Study of the New MTS.

Iroquois Falls - 4 to 12 kV Upgrade - Destroyes Sub – Downtown (16%)

This investment category is the second driver of spending within the System Service category, which involves converting the existing 4/2.4kV system to a 12.5/7.2kV wye system in the town of Iroquois Falls. This upgrade will remove the Destroyes distribution station from service and replace aging infrastructure. This system has no reference to ground and will not trip in case of a ground fault. The project aims to upgrade the line to current standards and replace deteriorated poles which helps address future outages. The completion of this project will bring improved safety and system efficiency.

Kapuskasing - 5Kv to 25 kV Conv. Upgrade (8%)

This investment category is the third driver of spending within the System Service category, which involves a voltage conversion from 4.16/2.4kV to 25/14.4kV in the town of Kapuskasing. The 4KV station has reached, or is very close to end of useful life, with assets identified as being in poor condition as per the ACA. This necessitated a strategic investment plan to ensure the continued delivery of safe and reliable power to customers. This project aligns with the company's commitment to providing safe, reliable, and cost-effective electricity, and is typical industry practice, with many utilities moving away from 4kV systems when the option arises.

Iroquois Falls - 2.4 to 12 kV Upgrade - Millgate Sub (5%)

This investment category is the third driver of spending within the System Service category, which involves converting the existing 2.4kV delta system to a 12.5/7.2kV wye system in the town of Iroquois Falls. This upgrade will remove the Mill Gate distribution station from service and replace aging infrastructure. The delta system has no reference to ground and will not trip in case of a ground fault. The project aims to upgrade the line to current standards and replace deteriorated poles which helps address future outages. The completion of this project will bring improved safety and system efficiency.

Cochrane Feeder Fortification (2%)

This investment category within System Service includes the replacement and re-stringing of conductors in the Cochrane region that are or past their end of life, conductor size is creating constraints on feeders and have been deemed in need of replacement due to being at end of life and in poor or very poor condition and having a high risk of failure as identified through the ACA.

The following table 5.4-12b also shows the spend on this category without the one off new MTS project. This is to demonstrate NOW Inc.'s typical spend when not carrying out identified one-off needed projects.

Table 5.4-14b: Forecast Net System Service Expenditures (excluding New Cochrane MS)

Category	Forecast 2025	2026	2027	2028	2029	Total	Percent of Total
	$ '000						
Kapuskasing - 5Kv to 25Kv Conv. Upgrade	627	1,000	-	-	-	1,627	25%
Iroquois Falls - 4 to 12 Kv Upgrade - Destroyes Sub - Downtown	-	-	1,227	1,090	1,090	3,407	52%
Iroquois Falls - 2.4 to 12 Kv Upgrade - Millgate Sub	1,071	-	-	-	-	1,071	16%
Cochrane Feeder Fortification	-	-	-	485	-	485	7%
Total Expenditure, Net	**1,698**	**1,000**	**1,227**	**1,575**	**1,090**	**6,590**	**100%**

5.4.1.2.4 General Plant

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

Table 5.4-15: Forecast Net General Plant Expenditures

Category	Forecast 2025	2026	2027	2028	2029	Total	Percent of Total
	$ '000						
Transportation Equipment	-	642	-	-	582	1,224	79%
Tools & Equipment	9	9	9	9	9	45	3%
Computer Hardware	5	5	5	5	5	25	2%

Category	Forecast 2025	2026	2027	2028	2029	Total	Percent of Total
	$ '000						
Computer Software	20	20	20	20	20	100	6%
Buildings	30	30	30	30	30	150	10%
Total Expenditure, Net	**64**	**706**	**64**	**64**	**646**	**1,544**	**100%**

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

Transportation Equipment (79%)

Investments in this category include purchasing of a bucket truck and a derrick digger.

Buildings (10%)

This category comprises of general investments and improvements to building and equipment at NOW Inc.'s service centers. Subsequent inspections and reports are performed to ensure building assets are replaced at the appropriate time. This program includes the replacement of overhead doors, storage facilities, building electrical works and miscellaneous.

Computer Software (6%)

Investments in this category include regular updates of billing system, software upgrades, changes to be implemented as required by regulation, replacement of end-of-life software assets, other business process efficiencies and adding modules to existing software solutions.

Tools & Equipment (3%)

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

Computer Hardware (2%)

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

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.

The only investment with a project life cycle that is greater than one year is the new Cochrane MTS and the costs will be in work in progress (WIP) until 2028 when the Station will be 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 NOW Inc.'s capital expenditures in the DSP's forecast period as compared to the historical period is provided in the following subsections.

5.4.1.3.1 Overall Capital Expenditures

The overall net capital expenditure trends over the 2017 to 2029 period are shown in Figure 5.4-1. The average overall capital expenditures forecast is approximately 392% higher than the historical plus bridge-year average. This is largely a result of the upcoming construction of the new Cochrane MTS, increased spend related to transportation equipment replacements, and increased System Renewal and System Service investments to maintain the overall condition and reliability of NOW Inc.'s system.

NOW Inc. has filed an Advanced capital Module (ACM) for the New Cochrane MTS. The ACM can be found at E2/T2/S5.

Comparing from 2017 to 2023, NOW Inc.'s average overall capital expenditures forecast is relatively constant with minor fluctuations in 2019 and 2023 and these have been explained in Section 5.4.1.1.

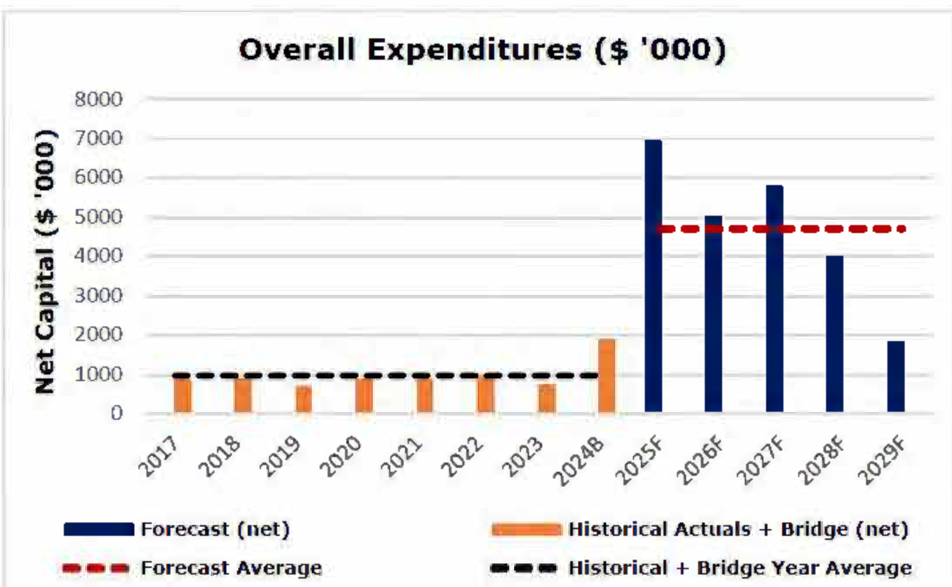


Figure 5.4-1: Overall Expenditures Comparison [Including the New MS]

The overall net capital expenditure trends over the 2017 to 2029 period excluding the new Cochrane MS project are shown in Figure 5.4-2 and it is observed the average overall capital expenditures forecast is approximately 90% higher than the historical plus bridge-year average. This is predominantly due to the identified needs under System Service investments as well as the much-needed vehicle replacements.

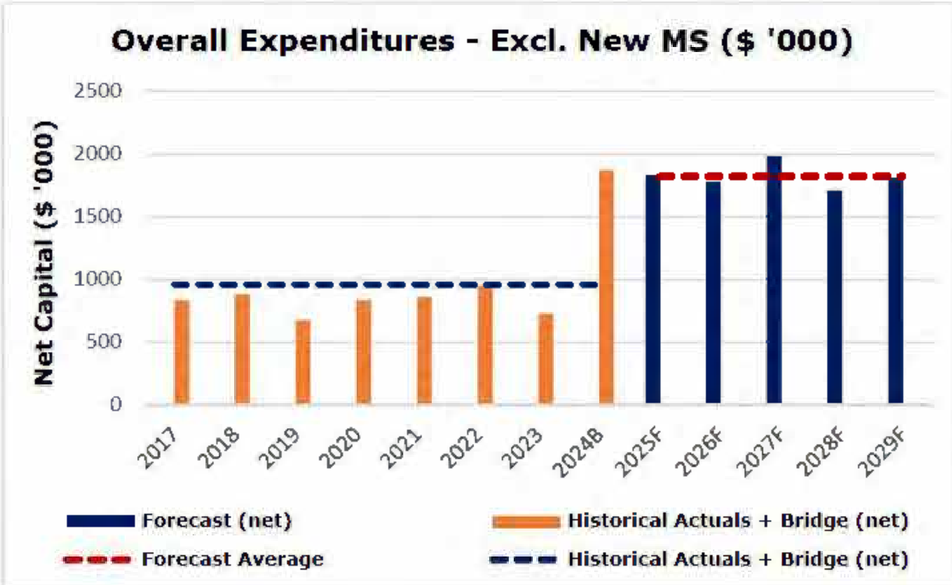


Figure 5.4-2: Overall Expenditures Comparison [Excluding the New MS]

As detailed in subsequent sections, excluding the new Cochrane MS project costs, the overall increase is driven by three main factors:

- The increase in System Service spending to modernize the distribution system, as well as begin the process of converting NOW Inc.'s three 4kV substations.
- The need for increased investment in System Renewal to maintain and upgrade equipment to ensure a safe and reliable electricity supply, as well as the significant increase in per unit replacement costs.
- Comparable spending (with respect to historical spending) in the General Plant category to maintain and upgrade NOW Inc.'s fleet, IT, buildings, tools, and equipment.

5.4.1.3.2 System Access

As shown in Figure 5.4-3, NOW Inc.'s System Access forecast average is 21% lower than the historical plus bridge year average. Since there is no growth in NOW Inc.'s service territory and since the respective Towns have not planned any road widening projects over the forecast period, NOW Inc. has not budgeted any capital expenditures due to customer service requests and third-party infrastructure development. NOW Inc.'s system access budget only includes metering, based on the expected rate of failure of the existing smart meters and the resource constraint of dispersing the meter replacement over the five years of the forecast period. The forecast System Access spending is expected to be relatively stable.

The historical System Access trend is variable year over year due to the unpredictability of customer connection service requests, externally initiated subdivision and relocation projects, metering upgrades, as well as third-party delays, deferrals, cancellations, and/or the introduction of new or additional works. The timing of the meter test results affected the schedule, leading to a lower meter replacement cycle achievement in 2021.

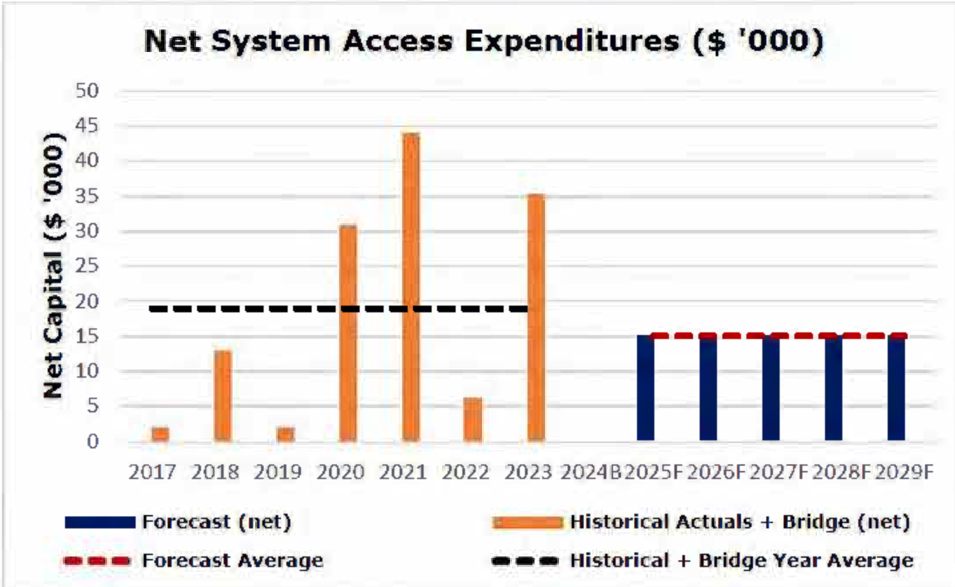


Figure 5.4-3: Net System Access Expenditures Comparison

5.4.1.3.3 System Renewal

System Renewal expenditures are impacted by planned capital investments and the objective to address any condition-based maintenance activities within the asset system to meet customer's expected performance and reliability. As shown in Figure 5.4-4, the forecast average for System Renewal is 34% lesser than the historical plus bridge year average.

The limited increase in forecast System Renewal spending is due to pole replacements in all three service territories of NOW Inc. Should any of these projects or needs change during the forecast period, NOW Inc. will reassess investment in other categories including System Renewal and reallocate expenditure to the next highest priority projects. 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 the customer's top priorities of maintaining affordable cost of electricity and maintaining and upgrading equipment to ensure a safe and reliable electricity supply.

The variation observed over the historical period are minimal except for a minor jump in 2021. This is due to a small increase in material costs due to COVID-19 impacts thereby accounted for an overall increase in the System Renewal spending.

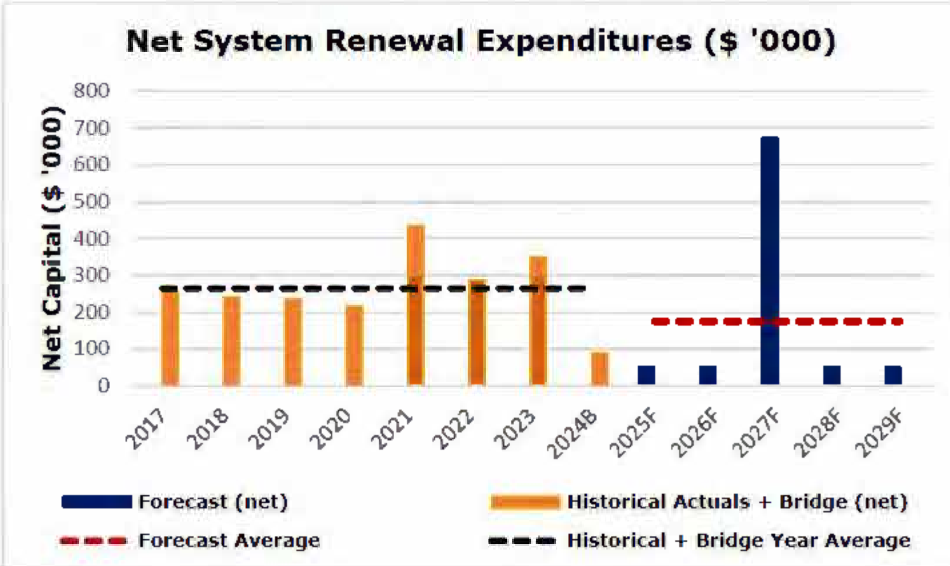


Figure 5.4-4: Net System Renewal Expenditures Comparison

The forecast System Renewal spending is relatively stable except for a big jump in 2027 which is due to the planned replacement of end-of-life transformers in the Cochrane region that have a high risk of failure as identified through the ACA. These investments will support the Cochrane feeder fortification and the new Cochrane TS project.

5.4.1.3.4 System Service

When including the New Cochrane MS project costs, the forecast average for System Service is 1095% greater than the historical plus bridge year average, as shown in Figure 5.4-5.

This significant increase is primarily due to the construction of a new Cochrane Municipal Station to address the current capacity constraints and future load growth. The spending for this new station is spread over the forecast period but is not constant. Continued development and construction of the new station is expected to continue over the forecast period.

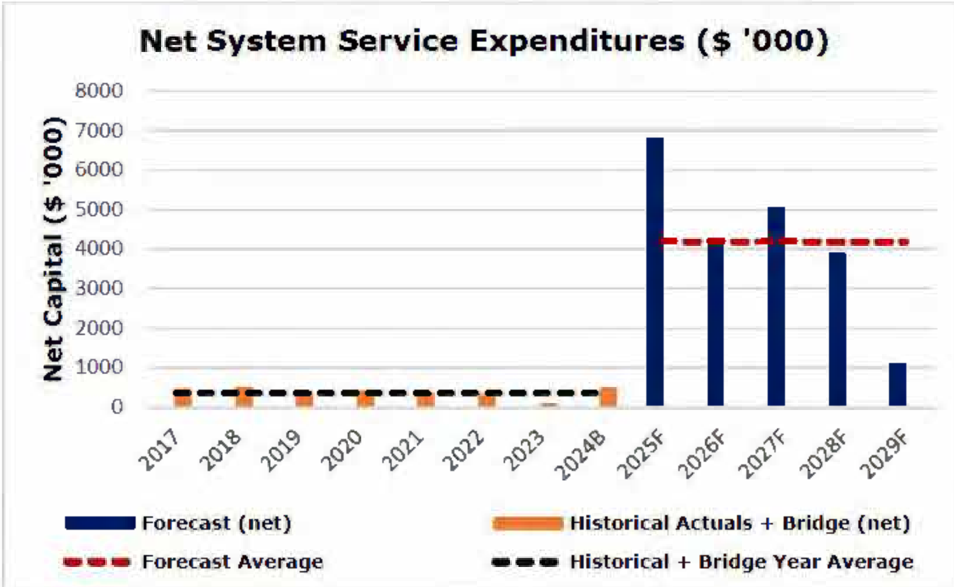


Figure 5.4-5: Net System Service Expenditures Comparison [Including the New MS]

When excluding these project costs associated with the New Cochrane MS project, the forecast average for System Service is 275% greater than the historical plus bridge year average, as shown in Figure 5.4-6.

The forecasted spending for the System Service, excluding costs related to the new Cochrane MTS project, exhibits significant fluctuations. There is a sharp increase in 2025, followed by a decline in 2026, a gradual rise until 2028, and a subsequent drop in 2029. The notable surge in 2025 is attributed to two voltage conversion programs in Kapuskasing and Iroquois Falls – Destroyes Sub (Downtown) and long lead times for purchases for the Cochrane MTS

The Kapuskasing voltage conversion program will continue into 2026 however the other voltage conversion program, in this region, will have been completed. This accounts for a slight reduction in the 2026 spending.

Additionally, the Iroquois Falls voltage conversion program, scheduled from 2027 to 2029, contributes to the increased expenditure, with further spending in 2028 associated with the Cochrane feeder fortification.

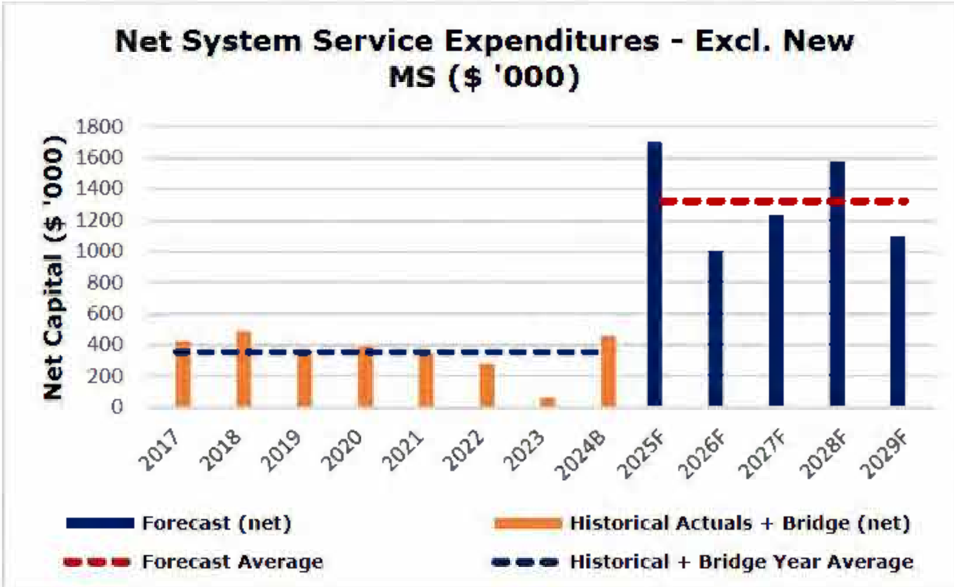


Figure 5.4-6: Net System Service Expenditures Comparison [Excluding the New MS]

The variation observed over the historical period are minimal except for a big dip in 2023. This is because, in 2023, NOW Inc. experienced some resource staffing issues which resulted in less capital expenditure being carried out.

5.4.1.3.5 General Plant

NOW Inc. continues to use its framework to address critical issues needed within the General Plant program, including existing facilities, fleet, and IT assets. As shown in Figure 5.4-7, the forecast average is 4% lower than the historical plus bridge year average. The limited increase in forecast General Plant spending is due to reduced but constant investments throughout the forecast period in NOW Inc.'s computer hardware and software, tools and equipment, and buildings. The forecast spending includes the cost to maintain NOW Inc.'s current fleet matrix that are past their useful life. The jump in 2026 and 2029 is explained by an increase in NOW Inc.'s transportation equipment which includes a bucket truck and a derrick digger.

Over the historical period, a relatively constant spending trend is observed except for a minor jump in 2022 and 2023. This is because NOW Inc. had not originally budgeted for spare parts in inventory change. In addition, work was identified to be carried out on service centres along with the purchase of a new folding machine.

The increase in spending for the bridge year is due to the procurement of a new bucket truck, a plot of land, power-operated tools (including a Hydro Vac and a new trencher), computer hardware and software for asset condition monitoring and enhancements.

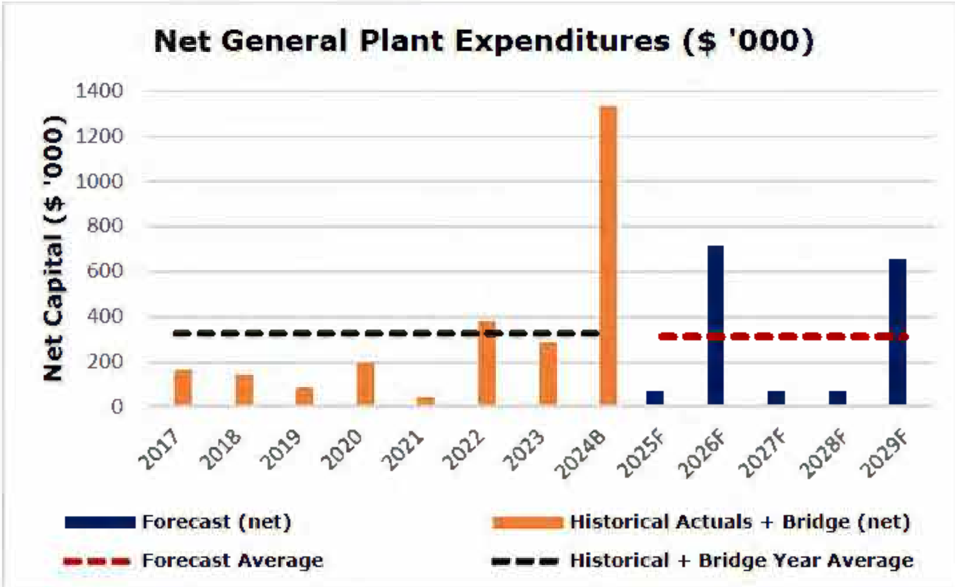


Figure 5.4-7: Net General Plant Expenditures Comparison

5.4.1.4 Important Modifications to Capital Programs Since Last DSP

A summary of any important modifications to typical capital programs since the last DSP (e.g., changes to individual asset strategies).

NOW Inc. has no major modifications to its typical capital programs since its last DSP.

5.4.1.5 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.

NOW Inc. forecast system O&M costs are expected to increase over the forecast period. This is a combination of a need to increase resources to deliver customers' expectations, including the capital plan, maintenance activities and respond in a timely manner to its customers. Additionally, NOW Inc. are looking to further enhance its maintenance practice, enhancing its vegetation management activities to help it improve its reliability.

Table 5.4-16: Forecast System O&M Expenditures

Category	Forecast ($ '000)				
	2025	2026	2027	2028	2029
System O&M	2,578	2,668	2,748	2,830	2,915

5.4.1.6 Non-Distribution Activities

A statement should be provided that there are no expenditures for non-distribution activities in the applicant's budget.

There is no expenditure included for non-distribution activities.

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.

NOW Inc.'s overall capital plan consists of many converging inputs that drive and influence the direction of the capital expenditures. NOW Inc.'s objective with regards to capital expenditures is to meet all regulated requirements while managing the assets in a manner that ensures the costs charged to its customers are prioritized and spent effectively.

The AM process is the foundation for the DSP and the capital expenditure plan which helps align each to NOW Inc.'s overall corporate objectives. By following a strategic approach to the capital expenditure planning process NOW Inc. achieves efficiencies in work practices and productivity along with creating and maintaining a distribution system capable of meeting the needs of existing and future customers. During the development of the capital expenditure plan, a number of objectives and planning processes are observed which ensures the plan aligns with the AM objectives and therefore with the overall strategic goals of the corporation (see section 5.3.1). NOW Inc.'s planning inputs that have shaped the DSP and capital expenditure plan include the following:

1. Provide the proper allocation of investments to meet Health and Safety obligations, ensuring the manner in which work is executed positively impacts the general public, customers and NOW Inc. staff.

2. Ensure proper allocation of investments to meet regulatory and customer obligation of system access projects (e.g., system relocations, residential and general services connections).

3. Ensure an adequate supply of power for existing and future demand needs.

4. Ensure adequate level of investment in the renewal of distribution system assets to maintain a safe and reliable system as determined through the continued ACAs.

5. Actively seek improvements in productivity and efficiencies that positively affect reliability and constraints on the system.

6. Review overall expenditures and determine impacts to financials and adjust spending as required.

The assumptions made during the planning process stem from input from various sources such as:

- Growth forecasts.
- Inspection and maintenance.
- Co-ordination with customers and third parties.
- Impact of regulatory initiatives.
- Historic system reliability.

- Asset condition forecasts, and
- Impact of CDM, REG, DER, and EV connections.

The degree to which each of these assumptions affects the overall capital plan varies along with the timing required to execute them. NOW Inc. strives for continuous improvement and as a result regularly reviews and revises the above planning assumptions to ensure they accurately reflect reality. As part of the capital expenditure planning process, NOW Inc. has determined several assumptions need to be made to support the development of the capital expenditure plan. Key assumptions include:

- The use of historical trends in categories related to System Access to forecast capital expenditures.
- The validity of information from developers, municipalities and other third parties with respect to future requirements of the distributions system to service new projects.
- The use of historical growth, CDM, DER and EV adoption rates as well as information from government and IESO reports for potential future growth or adoption of electrification to assist in the forecasting future contributions to the demand of the distribution system, and
- Third-party condition assessment reports that have helped inform System Renewal and General Plant investments.

NOW Inc.'s asset management goal is to identify and prioritize assets for replacement in an optimal manner through the guiding principles of the AM objectives, in such a way as to both; minimize risks to NOW Inc.'s vision and core values and maximize long term investment benefits. Each of the AM objectives described in section 5.3.1.1 are considered by utilizing them as weighted criteria to assist in the selection and prioritization of projects in the capital expenditure planning process.

<u>Customer Value</u>

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.

Delivering value to customers and other stakeholders is of critical importance to NOW Inc., as highlighted in NOW Inc.'s goal and values:

"Going forward NOW intends on being profitable while ensuring continued customer focus and strong customer service. NOW Inc. will utilize customer engagement results to continue to shape utility operations and explore alternative methods that customers are interested in. Maintaining high quality service in all three service territories is a focus of NOW Inc. which is increasingly important due to the challenges in Northern Ontario due to weather and the reliance customers have on maintaining a supply of quality power. Northern Ontario Wires Inc. will continue to pursue operational efficiencies through internal initiatives and through collaboration with other LDC's."

Meeting customers' needs and expectations is one of NOW Inc.'s AM objectives. These key inputs and objectives drive NOW Inc.'s planning and AM processes, and customer feedback is a key input considered when developing capital plans.

By prioritizing System Access projects, including new customer connections, service requests, new subdivisions, municipality driven projects, and joint use projects, as mandatory, NOW Inc. ensures that customer needs and requests are being met.

NOW Inc.'s System Renewal investments will address reliability, reduce system losses, and replace assets that are at end of life and deteriorating, by continuing its voltage conversion projects in both Kapuskasing and Iroquois Falls service areas. This is also in alignment with the results of the customer survey where approximately 67% of commercial customers and 43% of residential customers believed this amount of spend was appropriate to maintain the conditions of the distribution system.

The proposed System Service investments deliver value to customers by accommodating future load growth. Thereby, NOW Inc. plans to build a new station to facilitate additional load from customers and account for increased load due to electrification, which is consistent with their customer's desire for a reliable electricity supply and to invest money in new technologies, even if it means there is an additional cost.

NOW Inc.'s General Plant investments are also selected and prioritized such that they can continue to operate safely, efficiently and support other work. NOW Inc. is planning on continuing to invest in its computer hardware and software, buildings, and tools and equipment to enable the continued operation of its network.

In order to align NOW Inc.'s overall capital budget envelope with customer expectations, NOW Inc. has prioritized and optimized its proposed capital investments such that the most critical projects and programs have been budgeted over the forecast, while a number of lower priorities, less critical scoped projects and programs have been either deferred, reduced, or eliminated from the budget envelope.

Technological Changes and Innovation

A distributor should also keep pace with technological changes and integrate cost-effective innovative investments.

Facilitating innovation within an organization is essential to keep costs down and adapt to a rapidly changing business landscape. Innovation is also required to meet customer needs. NOW Inc. and McMillan Distribution Engineering have developed a plan for Kapuskasing fuse coordination, including the implementation of new technology called TripSaver reclosers. This technology will advance the lateral protection strategy by managing 80% of temporary overhead faults. It prevents these faults from becoming sustained outages and avoids momentary interruptions on feeders by blinking only the affected lateral, thereby mitigating a significant number of outages. This will improve outage statistics and will help reduce outage frequency and duration.in Kapuskasing, enhance reliability for our customers, reduce unnecessary truck rolls and O&M expenses, and improve customer satisfaction by minimizing the frustrating and costly consequences of outages. Additionally, it provides environmental benefits by reducing field trips and contributing to more sustainable operations.

System Modernization

NOW Inc. has identified the need to modernize aging infrastructure. The capital projects presented in this application will ensure it is ready for the evolving LDC landscape. The new

Cochrane MTS will feature modern SCADA and control system capabilities to support DER development. NOW Inc. is currently in talks with a third-party power generation company and exploring new distributed energy resources (DERs), distribution system operation, microgrid, and smart grid technologies as part of our goal towards a more modernized grid and sustainable future.

Consideration of Traditional Planning Needs

A distributor should also integrate traditional planning needs such as load growth, asset condition and reliability.

At a system level, load growth is not anticipated to drive investment during the forecast period as there are no constraints that would prevent the connection of anticipated load or generation customers.

As previously explained in Section 5.3.1, traditional planning needs, including load growth, asset condition, and reliability are key inputs considered as part of NOW Inc.'s AM processes.

Asset condition, inspection information and reliability data are key inputs considered by AM when identifying, selecting, and prioritizing System Renewal expenditures. It is through the ACA and inspection information that NOW Inc. can identify the portion of the system that has reached (or soon will) a point that requires renewal, and where in the system those assets pose the greatest risk to reliability and/or public safety. Asset quantities that are flagged for action directly influence the level of investment proposed over the forecast period and NOW Inc. has put forth investments that will yield sustained investment levels on a go forward basis as opposed to variable investment levels (i.e., to manage large demographics of assets in poor condition).

Overall Capital Expenditures

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.

The capital investments proposed in this distribution plan include investments into each of the four OEB categories: (1) system access; (2) system renewal; (3) system service and (4) general plant. The scope and timing of the investments in each category has been determined by considering all information available at the time of preparation of the distribution plan.

NOW Inc.'s Distribution System Plan is designed to support the achievement of the four key OEB established performance outcomes:

- Customer focus
- Operational effectiveness
- Public policy responsiveness
- Financial performance

Over the forecast period NOW Inc.'s capital expenditures are designed to continue to meet NOW Inc.'s corporate goals including safe, reliable, and affordable power. The proposed level of spending is also aimed at maintaining or slightly improving asset related performance in order to achieve the four performance outcomes established by the OEB, while also adhering to NOW Inc.'s established AM Objectives set out in Section 5.3.1.1.

As detailed in Section 5.4.1.3, the overall increase relative to historical is due to the following:

- Increased supply chain costs, i.e., higher inflationary costs being seen in labour, contractors, and material;
- Increase in end-of-life assets;
- The need to complete voltage conversion programs;
- The need to build a new station to facilitate additional load from customers; and
- To account for increased load due to electrification.

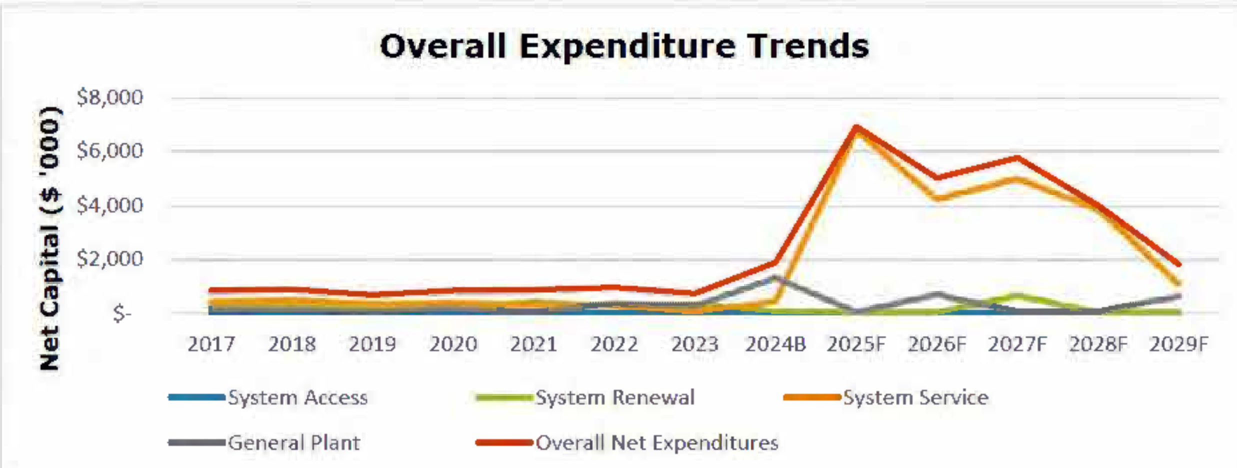


Figure 5.4-8: Overall Expenditure Trends [Including the New MS]

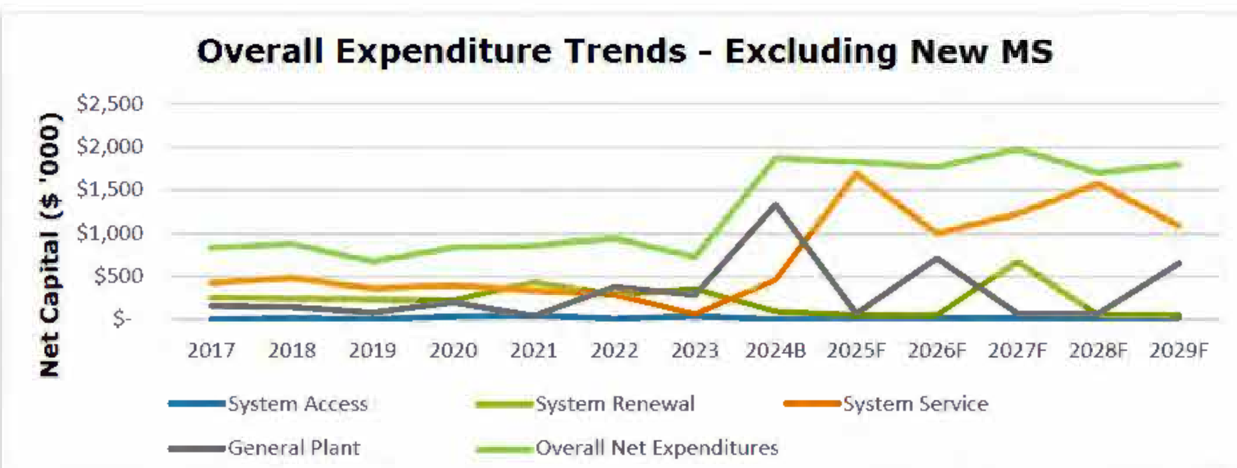


Figure 5.4-9: Overall Expenditure Trends [Excluding the New MS]

5.4.2.1 Material Investments

The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2A 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, NOW Inc.'s materiality threshold is $50,000. Using the prioritization process previously detailed in Section 5.3.1, NOW Inc. has ranked and prioritized its material investments planned in the Test Year (2025). Table 5.4-15 presents the prioritized list of material projects and programs that have been budgeted in 2025 with their associated prioritization scores.

For each of these projects/programs that exceed the materiality threshold, a detailed write-up, highlighting the drivers, justification, and analysis, is provided in Appendix A – Material Narratives.

Table 5.4-171: Proposed Capital Investments during Test Year - Projects over Materiality

Category	Project Description	Priority Rank	2025 Planned Expenditure ($ '000)
System Service	Iroquois Falls 2.4 kV to 12kV Upgrade - Destroyes Sub - Downtown & Millgate Sub	**1**	**1,071**
	Cochrane New MS	**2**	**5,088**
	Kapuskasing 4.15kV to 25kV Conversion	**3**	**627**
Total Expenditure on Material Projects During Test Year			**6,785**
Total Expenditure on Capital During Test Year (All Investment Categories)			**6,914**

Appendix A

Material Narratives

A ON THE PROJECT / PROGRAM

A distributor needs 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 benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. OVERVIEW

Overview of project/program need & scope.

NOW Inc. has planned a new Cochrane Municipal Transformer Station (MTS) to be constructed at an estimated budget cost of $5,088k in 2025 (the "test year"), followed by $9,299k between 2026 to 2028, with the station commissioned and in-service in 2028. This new station is required due to the aging infrastructure of the existing station, its inability to handle the expected load growth, and significant safety and environmental concerns.

The load in the Cochrane area is expected to increase substantially due to several factors. Two industrial customers have projected significant increases in their energy consumption, which will place additional strain on the aging system. Additionally, the rising adoption of electric vehicles (EVs) and the expected increase in air conditioning use due to warmer summer days will contribute to the overall load growth in the area. There is also a planned transfer of the existing 4.16kV load to the 25kV system, further intensifying the load on the current infrastructure.

The Cochrane MTS was built in the 1950s and has long been a critical component of the area's power infrastructure. However, after more than six decades of service, the station's age has become a significant concern. The two 10 MVA, 115/25kV transformers (T3 and T4), now 49 years old, along with the six single-phase 115/2.4kV transformers that feed the 4.16kV feeders, which range in age from 64 to 71 years old, are all outdated and have either reached or exceeded their typical useful life. The ACA of the transformers at the Cochrane MTS indicated a number of assets in poor condition, showing signs of degradation. As a result, the existing infrastructure is no longer adequate to meet the current and future demands of the area.

Beyond capacity concerns, the existing Cochrane MTS poses several safety and environmental risks. The station was constructed according to outdated standards, leading to significant safety issues. The low placement of busbars within the substation requires a full station outage whenever maintenance is needed, severely compromising operational reliability. The station's close proximity to the town's water supply presents an environmental risk, particularly the potential for transformer oil leaks that could contaminate the water source. There are also operational challenges due to the inability to use pesticides in the area surrounding the station, making it difficult to manage vegetation and other environmental factors effectively.

NOW Inc. evaluated several alternatives to address the capacity constraints and reliability concerns of the Cochrane MTS. One approach considered was to build a new Cochrane Municipal Station with two 18 MVA transformers. This solution was ultimately selected as the preferred option because it provides coverage of both current and anticipated future load demands, offers enhanced system flexibility and reliability, and reduces long-term maintenance and operational costs. Additionally, this option ensures that the new station is located away from the water supply, mitigating the environmental risks associated with the existing station.

Another approach proposed building a new station with a scaled-down scope, utilizing one 18 MVA transformer and retaining the existing two 10 MVA transformers as backup. While this approach offered initial cost savings, it was dismissed due to the inherent reliability risks associated with relying on 50+ year old transformers.

Maintaining the status quo was also considered but was deemed unsuitable. Without any upgrades or new construction, the existing infrastructure would continue to face risks of overloads and failures, with no capacity to support future load growth. Additionally, rebuilding the existing Cochrane MTS was reviewed. While this approach would address immediate reliability concerns, it involves significant challenges, including high long-term costs, potential operational disruptions during the rebuild process, and ongoing environmental concerns due to the station's proximity to the water supply.

Other options explored included the addition of Distributed Energy Resources (DER) to address capacity, obtaining emergency backup capacity through Hydro One's distribution system, and relying on participation in province-wide Conservation and Demand Management (CDM) programs. However, each of these alternatives presented limitations in terms of reliability, cost-effectiveness, and the ability to address the underlying issues with the aging infrastructure.

The new station will be built on the west side of Cochrane, chosen for its proximity to the Hydro One 115kV transmission supply and the availability of vacant land owned by the Town of Cochrane. A map highlighting the location of the site is provided below.

The strategic location of the new station not only ensures reliable access to the transmission supply but also optimizes land use, minimizing environmental impact and providing a sustainable solution for the Town of Cochrane's growing energy needs.

NOW Inc. determined that building a new Cochrane Municipal Station with two 18 MVA transformers is the most effective and sustainable solution. This option addresses the aging infrastructure, capacity constraints, and significant safety and environmental concerns associated with the existing station. To support its analysis and options assessments, NOW Inc. retained expert engineering consultants. By selecting a strategic location on the west side of Cochrane, close to the Hydro One 115kV transmission supply and on vacant land owned by the Town of Cochrane, the new station will ensure reliable access to the power grid. This investment is essential for securing the long-term reliability of Cochrane's power infrastructure, enabling the community to meet both current and future energy demands while maintaining a commitment to safety, environmental stewardship, and sustainable growth.

2. Timing

i. Start Date: 2025
ii. In-Service Date: 2028
iii. Key factors that may affect timing:

- Long lead times for materials.
- Design approvals.
- Land/Permitry approvals.
- Skilled experienced labour force availability.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)							Bridge Year	Future Costs ($ '000)				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital	0	0	0	0	0	0	0	0	5,088	3,233	3,780	2,286	0
Contributions	0	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	0	0	0	5,088	3,233	3,780	2,286	0

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

Not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

NOW Inc. has not undertaken a specific project of this scale and complexity in the recent past. However, the scope of work required for the construction of the new Cochrane MTS is closely aligned with other infrastructure upgrade projects that the contracting design and construction staff have completed. To support the cost development, quotes have been obtained from vendors.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

Using NOW Inc.'s prioritization process, this project is ranked 2 out of 8. The increased industrial demand and anticipated load growth, driven by rising temperatures and the adoption of electrification technologies such as EV chargers, underline the need for expanded capacity. The current system is unable to support the projected demand, and failure to address this would result in system overloads and potential service interruptions. Prioritizing this project ensures that NOW Inc. can meet both current and future load requirements, making it a critical investment.

The aging and poor condition infrastructure at the existing Cochrane Municipal Transformer Station, including transformers well beyond their useful life, presents significant risks to system reliability. The likelihood of equipment failure, combined with the inability to safely supply power to the Town of Cochrane during peak loads or unexpected failures, necessitates immediate action.

The current infrastructure also presents significant safety hazards to workers and environmental risks to the community, especially due to the proximity of aging transformers to the town's water supply. The installation of a new station is critical to allow for the decommissioning and removal of the outdated 4kV building and transformers, thereby eliminating these risks.

This project involves transferring the 4kV load to the 25kV system using 25/4kV transformers at the new station. While it does not directly transition the downstream 4kV infrastructure, it sets the stage for the future transition of these customers to the 25kV system. By enabling this critical step, the project aligns with current industry standards and ensures the long-term viability of the network. This foundational work is essential for reducing future maintenance costs, enhancing system reliability, and supporting future growth.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

The alternatives considered include building a new Cochrane Municipal Station, maintaining the status quo, and rebuilding the existing station. The preferred option is to construct a new station, which addresses current capacity constraints and future load growth while enhancing reliability, reducing maintenance costs, and supporting future electrification needs. Refer to detailed alternatives in Section 3 of Part ii in this document.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

Not applicable.

9. 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).

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.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	*Provide information on the effect of the investment on Efficiency (if applicable)* Project will improve overall distribution system capacity providing redundancy requirements. NOW Inc. has the land identified, which will ensure any permitting and impacts to customers will be minimized.
Customer Value	*Provide information on the effect of the investment on Customer Value (if applicable)* This project will support the future growth needs of key industrial customers, facilitate near-term electrification of the grid, and enable the supply of the 4kV system from the 25kV system. This will lay the groundwork for the future transition of the 4kV infrastructure, ensuring the network is equipped to handle anticipated demand and evolving energy requirements.
Reliability	*Provide information on the effect of the investment on Reliability (if applicable)* The new Cochrane Municipal Station will enhance system reliability by addressing the risk of transformer overloads at the existing station. With the anticipated increase in industrial load and the transition of 4.16kV loads to the 25kV system, the current transformers face potential overloads that could compromise power supply safety. The new station will improve load management and system resiliency, ensuring

	continuous and reliable power delivery even during peak loads or unexpected failures.
Safety	*Provide information on the effect of the investment on Safety (if applicable)* The new Cochrane Municipal Station will improve safety by addressing critical issues with the existing infrastructure. Outdated transformers pose a risk of oil leaks near the town's water supply, and the low-mounted buswork in the 4kV building creates safety hazards for workers. The new station will eliminate these risks, ensuring a safer environment for both the public and NOW Inc.'s workforce.

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*: Identify the main 'driver' ('trigger') of the project/program.*

Capacity Constraints - The main driver for the new Cochrane Municipal Station is the need to address capacity constraints in the current distribution system. Increased industrial demand and anticipated load growth necessitate expanding capacity to prevent overloads and ensure reliable power supply.

ii. Secondary Drivers*: Where applicable, identify any second drivers of the project/program.*

Failure Risk – The existing infrastructure, including outdated station equipment, poses a high risk of failure that could compromise system reliability and lead to service interruptions.

Reliability – The new station will enhance system reliability by improving load management and ensuring the ability to handle peak demands and unexpected failures without service interruptions.

Environmental/Safety – Replacing outdated equipment will eliminate safety hazards and environmental risks, such as transformer oil leaks near the town's water supply and safety concerns from low-mounted buswork.

iii. Information Used to Justify the Investment*: Identity by reference to the distributor's asset management process, the source and nature of the information used to justify the investment.*

Utilizing system metering data for the 4kV and 25kV systems, a historical coincidental peak demand and a 10-year forecast, based on projected demand increases and various load growth scenarios, have been completed. The analysis indicates that the peak load for the Town of Cochrane will surpass the redundant capacity of the 115/25kV distribution transformers. The Cochrane MTS transformers have significantly exceeded their useful life, showing signs of degradation and in poor condition. Consequently, the risk of failure is high, and a failure of either transformer during peak periods would result in an overload on the remaining transformer. This overload could compromise system stability, potentially leading to service interruptions and impacting all customers connected to the system. Such disruptions would affect the reliability of power supply and could result in significant inconvenience and economic losses for residents and businesses in the Town of Cochrane. For more detailed information, refer to Appendix A-1 – Consequences of Inaction Regarding 115kV and 25kV and 115 kV to 4.16kV Systems and Appendix A-2 - Northern Ontario Wires Feasibility Study New Transformer Station – Town of Cochrane Service Area for more details.

Combined 4 kV and 25 kV Distribution System Peak Load Forecast - Town of Cochrane

		Historical Data (kVA)					Near Term Forecast (kVA)					Medium Term Forecast (kVA)				
Season	Annual Growth %	2018*	2019	2020*	2021	2022	2023**	2024***	2025	2026	2027	2028	2029	2030	2031	2032
Summer	0%	11482	10466	11629	11411	10959	12129	12629	12629	12629	12629	12629	12629	12629	12629	12629
Summer	0.5%	11482	10521	11629	11411	10959	12190	12753	12817	12881	12945	13010	13075	13141	13206	13272
Summer	1.0%	11482	10521	11629	11411	10959	12250	12878	13007	13137	13268	13401	13535	13670	13807	13945
Winter	0%	13583	13107	12387	12493	12962	14083	14583	14934	14934	14934	14934	14934	14934	14934	14934
Winter	0.5%	13583	13107	12387	12493	12962	14153	14727	14800	14874	14949	15023	15099	15174	15250	15328
Winter	1%	13583	13107	12387	12493	12962	14224	14871	15020	15170	15322	15475	15630	15786	15944	16103

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, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: *Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change).*

The design of the new Cochrane Municipal Station exemplifies good utility practice by effectively addressing several critical aspects. Firstly, it accommodates the increasing load demands from customers by expanding capacity and enhancing system flexibility. This ensures that the distribution network can handle both current and anticipated future growth, avoiding potential overloads and maintaining a reliable power supply.

The project tackles the failure risk associated with the existing outdated infrastructure. The current equipment, including aging transformers, poses a significant risk of failure that could lead to service interruptions and system overloads. By upgrading to modern, reliable equipment, the new station reduces these risks, thereby enhancing the overall reliability of the power system.

Additionally, the new station supports the future transition of the downstream 4kV infrastructure to the 25kV system. This strategic move aligns with industry standards and prepares the network for future technological advancements and increased load requirements. It contributes to grid modernization efforts and ensures that the distribution system remains resilient in the face of evolving challenges, such as climate change and rising demand.

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.*

As part of the planning process NOW Inc. considered alternative projects to address the increased load requirements within the Town of Cochrane.

	Do Nothing	Build New Cochrane MTS			Existing Site		Additional Generation and DERS Options			Interconnection with Hydro One	CDM
Options:	**1:** Status Quo – Do Nothing	**2A:** Build New Cochrane MTS with 2 X 18 MVA Transformers **(Preferred Option)**	**2B:** Build New Cochrane MTS with 1 x 18 MVA transformer and relocate 2 x 10 MVA transformers from existing station to the new Cochrane MTS station for backup	**2C:** Build New Cochrane MTS with 1 x 18 MVA transformer and utilize 2 x 10 MVA located at existing Cochrane MTS as a back-up.	**3A:** Rebuild Existing Cochrane MS	**3B:** Rebuild Existing Cochrane MTS over longer time span	**4A:** Do nothing and add DERS to address capacity via IESO Commercial Market option.	**4B:** Do nothing and add DERS to address capacity as a customer resource.	**4C:** Do nothing and rely on Customer emergency standby generation to load shed to meet capacity requirements.	**5:** Interconnection with Hydro One Obtain emergency backup capacity through Hydro One Distribution System.	**6:** CDM - Obtain emergency backup capacity through Hydro One Distribution System.
Option Scope:	Maintain the current Cochrane Municipal Station as is, with no upgrades or new construction.	Construct new Cochrane Municipal Station.	Construct a new Cochrane Municipal Transformer Station scaled down scope and move the existing 2 - 10 MVA transformers from Cochrane MTS to the new site. The Cochrane MTS 4 kV substation would be replaced by installing 2 - 2 MVA 25 kV - 4 kV pad mounted step-down transformers at a more optimal location than Cochrane MTS.	Construct a new Cochrane MTS scaled down to 1 - 18 MVA transformer with provision for a future transformer. Redundancy would be temporarily available from Cochrane MTS existing 2 - 10 MVA transformer based on available useful life. Oil containment for the existing 2 - 10 MVA transformers would be constructed. The 4 kV substation would be supplied from the 25 kV system on site by 2 - 2 MVA step down transformers	Rebuild the existing Cochrane Municipal Station with modernized equipment and infrastructure at the existing location.	Rebuild the existing Cochrane Municipal Station with modernized equipment and infrastructure at the existing location over multiple Cost of Service rate periods.	Use DER (PV/BESS) to mitigate summer peak load.	Currently the option to interrupt large industrial customer load to address emergency operating conditions for overloading the 25 kV system may align to Industrial Customer interest in additional measures for reliability to support operations and enhance participation in the IESO ICI program.	Capabilities of customer emergency standby generation would be called upon to reduce system loading during times of single transformer contingency scenarios	Do nothing and rely on Hydro One for additional capacity relief.	Do nothing and rely on participation in province wide CDM programs or custom programs proposed by NOW Inc.
Annual Benefits:	No immediate benefits.	Ensures reliable power supply, meets current and future load demands, reduces maintenance costs, and enhances system reliability. Address safety any environmental concerns of existing station.	Reduces budget by $2.5M but relies on aging transformers, which presents ongoing risks. This option addresses load growth, safety, and reliability of the 4 kV substation and retains remaining useful life of the existing 25 kV transformers as a backup. Allows for the removal of equipment and remediation of the Cochrane MTS site.	Slight budget reduction, but aging infrastructure continues to pose risks. May save some costs in the short term. This option solves the capacity issue and the reliability and safety concerns related to the 4 kV substation.	Fixes existing load constraints but involves significant costs and operational disruptions.	Stretches the rebuild cost over time, reducing immediate financial burden but prolonging operational disruptions. Minimizes overall rate impact to customers.	Potential financial benefits from IESO participation but does not address underlying infrastructure issues. The new MTS also allows for conversion of 4 kV load to the 25 kV distribution system and remediation of the 4 kV substation.	Similar financial benefits from DERS participation but depends heavily on customer cooperation and may not be reliable.	No long-term benefits. Only a temporary solution during peak periods with risks of inadequate capacity.	Provides additional capacity during emergencies but does not address underlying infrastructure issues.	Provides some load reduction during peak periods but may not be sufficient for long-term needs.
Economics:	No initial cost, but higher long-term costs due to increasing maintenance and failure risks.	Higher upfront cost, but long-term savings from reduced maintenance and operational efficiencies.	Lower initial cost but ongoing risks and potential future expenses due to aging infrastructure.	Initial savings, but higher long-term costs due to reliance on aging infrastructure and necessary upgrades.	Significant upfront cost, with high long-term operational savings due to modernized infrastructure.	Spread-out costs, but higher total costs due to prolonged construction and operational inefficiencies.	Financial incentives from IESO participation, but long-term costs remain due to unresolved infrastructure issues.	Lower initial costs, but potential long-term financial risks due to reliance on customer resources.	Minimal upfront costs, but potentially high long-term costs if capacity is inadequate during peak demand.	Lower initial costs, but higher long-term costs if Hydro One cannot meet capacity demands.	Limited financial savings, with potential high long-term costs due to insufficient load reduction.
Other Constraining Factors:	Ongoing infrastructure continues to pose safety and reliability risks.	Requires significant land and resources but provides long-term security.	Relies on 50-year-old transformers, which continue to pose risks.	Oil containment and feeder egress issues persist, affecting reliability.	Proximity to the water supply continues to be a significant environmental concern.	Extends environmental and operational risks due to prolonged construction.	Technology challenges and market participation may not align with local needs.	Customer participation may be insufficient to meet capacity needs.	High risk of inadequate standby generation capacity, leading to potential outages.	May require voltage transformation and alignment with Hydro One's capacity.	CDM programs may not provide enough load reduction, leading to potential capacity shortfalls.
Customer Feedback:	Through its DSP survey conducted in August 2024, the majority of customers expressed support for NOW Inc.'s proposed investment in the new station. Many customers agreed that this investment is crucial to meet the growing demand in the area and to replace the station assets that have reached the end of their useful life. NOW Inc. has identified a clear load demand need to fulfill its legislative requirements of delivering reliable electricity to its residents. Given the circumstances, NOW Inc. sees no option other than to proceed with this investment.										
Total Gross CapEx	$0	Equipment: $10161k Design: $328k Construction: $405k Valard Equipment/Construction /Design: $3251k Commissioning: $142k Site Preparation: $100k **Total Cost: $14,486k**	Equipment: $7867k Design: $328k Construction: $405k Valard Equipment/Construction /Design: $3251k Commissioning: $142k Site Preparation: $100k Move Existing Transformers: $170k **Total Cost: $12,263k**	Equipment: $6798k Design: $328k Construction: $233k Valard Equipment/Construction /Design: $2167k Commissioning: $74k Site Preparation: $100k Existing Site Remediation: $320k **Total Cost: $10,020k**	Rebuilding at the existing Cochrane MTS site is not cost-effective, as all equipment must be replaced. The station would need to be rebuilt due to obsolete standards, resulting in higher costs compared to constructing a new station at a different site. Therefore, building at a new site offers significant financial and operational advantages.	Rebuilding at the existing Cochrane MTS site is not cost-effective, as all equipment must be replaced. The station would need to be rebuilt due to obsolete standards, resulting in higher costs compared to constructing a new station at a different site. Therefore, building at a new site offers significant financial and operational advantages.	Not a feasible solution as it fails to address the aging infrastructure. While DERs may provide temporary capacity relief, they do not resolve the ongoing risks posed by outdated equipment, leading to potential reliability and safety issues.	Not a feasible solution as it relies on customer participation without addressing the aging infrastructure. This approach does not mitigate the long-term risks associated with outdated equipment and could lead to unreliable power supply.	Not a feasible solution as it does not address the aging infrastructure. Relying on emergency standby generation introduces a high risk of insufficient capacity during peak demand, leaving the system vulnerable to failures.	Not a feasible solution as it does not solve the problem of aging infrastructure. While interconnection might provide additional capacity, it does not mitigate the risks associated with outdated equipment, leading to potential reliability and safety concerns.	Not a feasible solution as it does not address the aging infrastructure issue. CDM programs may reduce load temporarily, but they do not eliminate the long-term risks posed by obsolete equipment, which could compromise system reliability.

iii. Historical Investments & Outcomes Observed: *Show past costs for similar investments and the outcomes the distributor observed to support the requested capital investments.*

NOW Inc. has completed several projects over the past 10 years that have contributed to the system reliability for customers as measured through improved SAIDI and SAIFI statistics. These projects have increased NOW Inc.'s ability to balance load, more effectively switch load under normal and outage related situation.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

i. Project Deferrals: *The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred*
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*
iii. Use of Advanced Technology: *A description of how advanced technology has been incorporated into the project (if applicable)*

Not applicable – NOW Inc. identified no clear CDM option that would be able to meet the drivers and needs of this project.

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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies*

The Cochrane station project embraces innovation by integrating advanced SCADA and SEL networks for real-time monitoring and control, load-shedding capabilities for effective demand management, and futureproofing for smart grid expansion and Distributed Energy Resources (DER) integration. These innovations enhance reliability, optimize grid efficiency, and provide greater customer choice while supporting conservation efforts.

A. General Information on the Project / Program

A distributor needs 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 benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

This project involves converting the existing 2.4kV delta system to a 12.5/7.2kV wye system in the town of Iroquois Falls. The upgrade is necessary to remove the Mill Gate distribution station from service and replace aging infrastructure. The delta system has no reference to ground and will not trip in case of a ground fault. The existing poles are starting to show signs of deterioration. The replacement of #6 copper conductors with 3/0 ACSR will reduce the probability of conductors breaking in the event of a storm or maintenance work. The line will be upgraded to current standards and the replacement of deteriorated poles is expected to avoid future outages. The completion of this project will bring improved safety and system efficiency.

The project will replace approximately 2,570 meters of three-phase line, including 86 poles and 21 single-phase transformers. The existing infrastructure has an average age of 47 years, exceeding the typical useful life (TUL) of overhead transformers (40 years), pad-mounted transformers (40 years), and wood poles (45 years).

The main driver for this project is that most of the station critical assets, are in fair or worse condition and past, or very near, the end of their typical useful life. This project is urgently needed because the conversion of the entire community is scheduled to be completed by 2025, and reports and analysis indicate that investment at the stations must occur within this timeframe. The current pacing is designed to remove the station from service before it experiences a failure or requires significant capital investment.

This project is necessary to decommission the Mill Gate DS from service and to replace aging infrastructure. The existing poles are the oldest and visual checks confirmed their condition. The poles will be monitored going forward using line patrols. The completion of this project will bring improved safety and system efficiency and reduce operating costs.

The forecasted budget for this project is $1,070k in 2025 (the "test year"), at which point the delta to wye voltage conversion for Mill Gate DS will be complete.

2. Timing

i. Start Date: March 1, 2025
ii. In-Service Date: November 30, 2025
iii. Key factors that may affect timing:
- Unplanned or higher priority work arises, resulting in resource constraints.
- Delays in design/approval process.
- Material procurement delays.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)							Bridge Year	Future Costs ($ '000)				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital	204	122	93	69	5	17	54	170	1,071	0	0	0	0
Contributions	0	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	204	122	93	69	5	17	54	170	1,071	0	0	0	0

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

Not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

Historical voltage conversion costs have been utilized to inform the forecasted costs, with adjustments made to account for increases in labor, inflation, and material costs.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

Using NOW Inc.'s prioritization process, this project is ranked 1 out of 8. The benefit of removing the need to invest significantly in the Mill Gate distribution station replacement are main factors that influence the project ranking. Not completing this project will result in NOW Inc. incurring a significant capital investment when the 2.4kV delta system assets require upgrades. It is important that NOW Inc. completes the conversion project to simplify, standardize and improve the overall performance and efficiency of the distribution system and continue providing power in a cost-effective manner.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

The options for this project include:

Option 1 (Preferred Option) - Upgrade 2.4 Delta to 12.5/7.2kV Wye system: Upgrading from the existing 2.4 Delta to 12.5/7.2 kV Wye is the proposed solution. This mitigates the safety hazards due to delta system, reliability issues due to aged infrastructure, potential line losses, and system O&M costs. This brings NOW Inc. closer to the decommissioning of a delta station, which is the optimal approach.

Option 2 - Do Nothing: The "do nothing" option will fail to realize any of the project benefits. The delta system will continue to be a safety hazard in case of a ground fault. A delta station decommission plan in the near future will not be achieved, and NOW Inc. will continue spending on maintenance of the station. Since the existing poles and transformers have reached or exceeded TUL, they are expected to cause customer outages. Energy losses will be higher on the 2.4kV delta system, especially due to the #6 copper conductors and the 40-year-old transformers. Finally, the #6 copper conductors have a higher chance of abrasion during high winds or line maintenance, which will also cause customer outages and increase the number of trouble calls.

Option 3 - Replace 2.4kV Delta Feeder with Underground Feeder: Replacing the 2.4kV overhead feeder with an underground feeder is an option, but it is significantly more expensive. Due to its higher cost, this alternative is not recommended.

Option 4 - Rebuild 2.4kV Delta Feeder with 4.16/2.4kV Wye Feeder: Although this approach mitigates the safety issues of the delta system, other long-term benefits such as reduced line losses and the ability to decommission a station will not be achieved, as an additional 4.16/2.4 kV station would be required. Even with this approach, replacement of all the assets is required since they have already reached TUL and are in poor condition.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

Although not a main driver, this project will enable future technological functionality and address future operational requirements to meeting the changing needs of customers, industry, and regulators.

9. 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).

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.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	*Provide information on the effect of the investment on Efficiency (if applicable)* Upgrading the 2.4kV delta system to a 12.5/7.2kV wye system will result in greater operating efficiency, reduced power losses, and standardized equipment, allowing for purchasing efficiencies. The replacement of #6 copper conductors with 3/0 ACSR will further reduce power

	losses and improve the overall efficiency of the distribution system.
Customer Value	*Provide information on the effect of the investment on Customer Value (if applicable)* With the conversion of Iroquois Falls to 12.5/7.2kV, NOW Inc. anticipates the following benefits to customers: • Eliminate older, end-of-life 2.4kV delta distribution assets. • Provide the most effective long-term solution by reducing the probability of outages due to aged infrastructure. • Reduce system losses through the elimination of the delta station. • Allow for the connection of larger loads and generators. • Conform to the standard voltage across the province, making it easier to source material and expertise. • Eliminate the use of outdated, difficult-to-operate, and maintain equipment. • Eliminate the need for the Mill Gate distribution station and simplify the operation of the distribution system. • Avert potentially adverse effects on reliability and safety. • Avoid increased maintenance costs to continue operating and maintaining these assets.
Reliability	*Provide information on the effect of the investment on Reliability (if applicable)* The completion of this project is expected to address reliability over time by: • Reducing the risk of prolonged outages associated with aged infrastructure, including poles, conductors, and transformers. • Upgrading distribution system assets, built to today's standards, to withstand more adverse weather conditions. • Replacing deteriorated poles and conductors to improve the overall reliability of the distribution system.
Safety	*Provide information on the effect of the investment on Safety (if applicable)* The project will improve safety by: • Replacing aging poles, significantly reducing the risk of pole failures due to deterioration. • Converting to a wye system with a solid ground reference, ensuring the system will trip in the

	event of a ground fault, reducing the risk of accidents and injuries.

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*: Identify the main 'driver' ('trigger') of the project/program.*
Improved Safety – The primary driver of this project is improved safety. The new wye system provides ground reference and will trip in case of a ground fault, significantly enhancing the safety of the distribution system.

ii. Secondary Drivers*: Where applicable, identify any second drivers of the project/program.*
Customers - At its core, NOW Inc. exists to provide safe, reliable electricity supply to its customers in a cost-effective manner. This project represents the most cost-effective way for NOW Inc. to service the long term needs of this community, by removing the need to heavily invest in station rebuilds.

Reliability – This project also addresses reliability concerns. Replacing deteriorated poles reduces the likelihood of pole failure during high winds. Moreover, increasing the conductor size from #6 copper to 3/0 ACSR decreases the chance of conductor breakage during adverse weather or line maintenance.

Efficiency – The project is expected to improve overall system efficiency. The 12.5/7.2 kV system can deliver the same power at a lower current compared to the 2.4 kV delta system, thereby reducing line losses. Increasing the conductor size and replacing 69-year-old transformers will further contribute to reducing line losses, enhancing operational efficiency and cost-effectiveness.

iii. Information Used to Justify the Investment*: Identity by reference to the distributor's asset management process, the source and nature of the information used to justify the investment.*

NOW Inc's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of the 2.4kV delta to 12kV wye conversion program. The majority of the assets that will be replaced as part of the program are in poor condition or worse as identified by the ACA, and the station that will be removed from service upon completion of this project will eliminate the need for NOW Inc. to allocate significant capital into upgrading the station in the future as they have either already surpassed or are approaching their expected service life, with critical assets in poor condition. This solution provides the most economical alternative to station rebuilds in this community. In addition to this, by replacing assets in poor condition, this investment prevents the power supply reliability from degrading below NOW Inc's targets. The planned replacement and conversion projects are essential in maintaining a reliable distribution system for 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, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: *Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change).*

NOW Inc. utilizes Utility Standards Forum design standards. The use of newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability.

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.*

NOW Inc. NOW Inc. has assessed the Delta to Wye voltage conversion project for the area served by the Mill Gate Distribution Station as a critical investment. Rebuilding the station is not feasible due obsolete equipment, making this conversion project the most viable solution. Additionally, the conductor, pole, and transformer replacements in this community is essential, as many of the assets being replaced are already in poor or very poor condition and require urgent attention. This investment also reduces future operating and maintenance costs that would arise from continuing the operation of the Mill Gate Distribution Station.

iii. Historical Investments & Outcomes Observed: *Show past costs for similar investments and the outcomes the distributor observed to support the requested capital investments.*

NOW Inc. has successfully completed several voltage conversion projects, including transitions from delta to wye configurations, and has observed numerous positive outcomes. These benefits include improved system efficiency, reduced losses, and increased standardization, which leads to reduced inventory requirements. Replacing end-of-life and poor-condition assets as part of these conversions also contributes to maintaining or enhancing system reliability.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through *distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.*

i. Project Deferrals: *The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred*
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*
iii. Use of Advanced Technology: *A description of how advanced technology has been incorporated into the project (if applicable)*

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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies*

Not Applicable.

Material Investment Narrative
Investment Category: System Service - Kapuskasing - 5Kv to 25Kv Conv. Upgrade

A. General Information on the Project / Program

A distributor needs 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 benefit of the recommended alternative. As well, a description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Overview of project/program need & scope.

This project is a voltage conversion from 4.16/2.4kV to 25/14.4kV in the town of Kapuskasing. The 4KV station has reached, or is very close to end of useful life, with assets identified as being in poor condition as per the ACA. This necessitated a strategic investment plan to ensure the continued delivery of safe and reliable power to customers. Recognizing the financial implications of replacing the entire station, the decision to create a voltage conversion project from 4.16/2.4kV to 25/14.4kV was selected as the most effective solution. This also aligned with the company's commitment to providing safe, reliable, and cost-effective electricity, and is typical industry practice, with many utilities moving away from 4kV systems when the option arises.

This project will replace approximately 7,970m of three-phase line, which comprises of 108 poles and 19 single-phase transformers. The average age of the existing infrastructure is 47 years, which is past the TUL of overhead transformers (40 years) and wood poles (45 years).

The main driver for this project is that most of the station critical assets, are in fair or worse condition and past, or very near, the end of their TUL. This specific project is needed now as the conversion of the entire community at the proposed pace will take until 2026 year and reports and analysis indicate investment would need to occur at the station within this timeline. This pacing is planned to allow the station to be removed from service prior to experiencing a failure or requiring significant capital investment to complete.

This project is necessary to remove a 4.16/2.4kV station from service and to replace aging infrastructure. The existing poles are the oldest and visual checks confirmed their condition. The pole will be monitored going forward using line patrols. The completion of this project will bring improved safety and system efficiency and reduce operating costs.

The projected budget for this project is $627k in 2025 (the "test year"), followed by $1,000k in 2026, at which point the voltage conversion in Kapuskasing will be completed.

2. Timing

i. Start Date: March 1, 2025
ii. In-Service Date: November 30, 2025
iii. Key factors that may affect timing:
- Unplanned or higher priority work arises, resulting in resource constraints.
- Delays in design/approval process.
- Material procurement delays.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)							Bridge Year	Future Costs ($ '000)				
	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital	222	365	267	326	336	265	7	286	627	1,000	0	0	0
Contributions	0	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	222	365	267	326	336	265	7	286	627	1,000	0	0	0

4. Economic Evaluation (Expansion Projects)

Please provide an economic evaluation as per section 3.2 of the distribution system code if applicable.

Not applicable.

5. Comparative Historical Expenditure

Where available, comparative information on expenditures for equivalent projects/programs over the historical period (e.g. cost per km of line, cost per pole).

For similar voltage and delta-to-wye conversion projects of this scale, NOW Inc. has historically experienced an average cost of $215k per 1,000 meters of conversion. This aligns with the forecasted budget for the current project.

6. Investment Priority

Indicate the priority of the investment relative to others, giving reasons for assigning this priority that clearly reflect the distributor's approach to identifying, selecting, prioritizing, and pacing projects in each investment category.

Using NOW Inc.'s prioritization process, this project is ranked 3 out of 8. The benefit of removing the need to invest significantly in 4kV station replacement are main factors that influence the project ranking. Not completing this project will result in NOW Inc. incurring a significant capital investment when the 4kV station requires upgrades. It is important that NOW Inc. completes the conversion project to simplify, standardize and improve the overall performance and efficiency of the distribution system and continue providing power in a cost-effective manner.

7. Alternatives Analysis

Explain the alternative investments that were considered and the cost-benefit of the recommended alternative.

The projects identified in this category are based on a voltage conversion plan which considers the condition of the distribution station transformers, the loads it feeds and the age/condition of the infrastructure. To decide on the best course of action, NOW Inc. considered the following alternatives:

Option 1 (Preferred Option) - Upgrade 4.16/2.4kV to 25/14.4kV: Upgrading from 4.16/2.4kV to 25/14.4kV is the proposed solution. This upgrade addresses reliability issues caused by the aging infrastructure, reduces potential line losses, and decreases system operation and maintenance costs. It also brings NOW Inc. closer to achieving the decommissioning of the outdated 4.16kV station, aligning with the optimal long-term strategy.

Option 2 - Do Nothing: The "do nothing" option will fail to realize any of the project benefits. It will prevent the decommissioning of the 4.16kV station, forcing NOW Inc. to continue incurring maintenance costs for the station, and any future capital costs. With the existing poles and transformers having reached or exceeded their TUL, this approach is likely to lead to increased customer outages and trouble calls, along with higher energy losses due to the lower voltage system and aging infrastructure.

Option 3 - Replace 4.16/2.4kV Feeder with Underground Feeder: Replacing the 4.16/2.4kV overhead feeder with an underground feeder is an option, but it is significantly more expensive. Due to its higher cost, this alternative is not recommended.

Option 4 - Rebuild 4.16/2.4kV Feeder: Rebuilding the 4.16/2.4kV feeder could replace the aging infrastructure, but it does not advance NOW Inc.'s goal of decommissioning the 4.16kV station. Power in Kapuskasing is received from the HONI-owned Kapuskasing DS feeder M2 at 25/14.4kV, and rebuilding would not contribute to reducing maintenance costs for the 4.16kV station.

8. Innovative Nature of the Project

If investment is innovative and distinct from others, explain the nature of the project and elucidate what makes it innovative (if applicable).

Although not a main driver behind the project, it will enable future technological functionality and address future operational requirements to meeting the change needs of customers, industry, and regulators.

9. 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).

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.

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	*Provide information on the effect of the investment on Efficiency (if applicable)*

	Upgrading the 4.16/2.4kV equipment to 25/14.4kV equipment will result in greater operating efficiency, reduced power losses, and standardized equipment allowing for purchasing efficiencies.
Customer Value	*Provide information on the effect of the investment on Customer Value (if applicable)* With the conversion of Kapuskasing to 25/14.4kV NOW Inc. anticipates the following benefits to customers: • Eliminate older, end of life 4kV distribution assets. • Provide most-effective long-term solution. • Reduce system losses through the elimination of the 4kV station. • Allow for the connection of larger loads and generators. • Conform to the standard voltage across the province making it easier to source material and expertise. • Eliminate the use of outdated, difficult to operate and maintain equipment. • Eliminate the need for 4kV station and simplify the operation of the distribution system, as well as eliminating the need to invest in refurbishing and maintaining the station. • Aversion of potentially adverse effects on reliability and safety; and • Avoidance of an increase in maintenance costs to continue to operate and maintain these assets.
Reliability	*Provide information on the effect of the investment on Reliability (if applicable)* The completion of this project is expected to address reliability over time for the following reasons: • Reduced risk of prolonged outages associated with aged station equipment needing replacement. • Distribution system assets, built in today's standards can withstand more adverse weather conditions and, in overhead construction have increased clearances around the conductors to assist in reducing the frequency and duration of outages.
Safety	*Provide information on the effect of the investment on Safety (if applicable)* The project will improve safety by replacing aging poles, significantly reducing the risk of pole failures due to deterioration.

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*: Identify the main 'driver' ('trigger') of the project/program.*
Reliability – The main driver for this project is aimed at addressing failure risk. Most of the remaining distribution infrastructure operating at 4.16kV within Kapuskasing is at the end of its service life and in poor condition, making it some of the highest risk assets for failure. The 4.16kV station has also surpassed or approaching the end of life creating increased safety and reliability risks. Decommissioning the substation is not feasible without the complete system conversion. With rebuilt distribution assets, the system is expected to be more dependable, providing customers with access to reliable electricity.

ii. Secondary Drivers*: Where applicable, identify any second drivers of the project/program.*
Customer Needs - This project represents the most cost-effective way for NOW Inc. to service the long term needs of this community, by removing the need to heavily invest in station rebuilds.

Productivity/Efficiency - The effect of these investments is an improvement in operational efficiency and cost-effectiveness by reducing line losses, increasing capacity for connections of new loads, as well as removing the capital and operating expenses that would otherwise be required with the substation that will be removed from service as part of this project.

iii. Information Used to Justify the Investment*: Identity by reference to the distributor's asset management process, the source and nature of the information used to justify the investment.*

NOW Inc's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP) inform the execution of the 4kV conversion program. The majority of the assets that will be replaced as part of the program are in poor condition or worse as identified by the ACA, and the station that will be removed from service upon completion of this project will eliminate the need for NOW Inc. to allocate significant capital into upgrading the station in the future as they have either already surpassed or are approaching their expected service life, with critical assets in poor condition. This solution provides the most economical alternative to station rebuilds in this community. In addition to this, by replacing assets in poor condition, this investment prevents the power supply reliability from degrading below NOW Inc.'s targets. The planned replacement and conversion projects are essential in maintaining a reliable distribution system for 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, benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. Demonstrating Accepted Utility Practice: *Demonstrate good utility practice in reliability planning through designing a resilient distribution system that addresses existing reliability performance concerns and is capable of adapting to future challenges (e.g. grid modernization and climate change).*

NOW Inc. utilizes Utility Standards Forum design standards. The use of newer construction standards and materials provide for more weather resilient assets to help maintain safety and reliability.

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.*

NOW Inc. has evaluated the voltage conversion project in the Kapuskasing service area, recognizing that the project presents significant benefits. By performing this voltage conversion, NOW Inc. avoids the substantial costs associated with rebuilding the station. Additionally, cable replacement would eventually be necessary in this community, as many of the assets being replaced have been identified as being in poor or very poor condition, requiring imminent replacement. This investment also eliminates future operating and maintenance costs that would arise from continuing the operation of the 4.16kV station.

iii. Historical Investments & Outcomes Observed: *Show past costs for similar investments and the outcomes the distributor observed to support the requested capital investments.*

NOW Inc. has completed several voltage conversion projects 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: *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, benefits for customers (short/long term), and impact on distributor costs (short/long term).*

Not applicable.

4. Conservation and Demand Management

A distributor should consider opportunities to defer or avoid future infrastructure through CDM, as described in the CDM Guidelines. To propose a CDM initiative funded through distribution rates, a distributor should provide the number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred, a cost-to-benefit analysis, and if advance technology has been incorporated.

i. Project Deferrals: *The number of years the proposed CDM program would be in place and the number of years that the required infrastructure would be deferred*
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*
iii. Use of Advanced Technology: *A description of how advanced technology has been incorporated into the project (if applicable)*

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. 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.

i. Assessment of Benefit for Customers: *This can include as improved reliability, enhanced customer services, conservation and demand management, efficient use of electricity, load management, greater efficiency through grid optimization, lower rates (long-term or short-term), enhanced customer choice, or any other benefit consistent with the OEB's mandate and policies*

Not Applicable.

Appendix A-1

3i0 - Consequences of Inaction Regarding 115kV to 25kV and 115kV to 4.16kV Systems

Northern Ontario Wires Inc.

Consequences of Inaction Regarding 115 kV to 25 kV and

115 kV to 4.16 kV Systems

June 28, 2023

Report by: Jason Fortier, P. Eng.

Introduction

In June of 2023, Northern Ontario Wires reached out to 3i0 Inc. for assistance in determining the risks associated with the aged equipment within their distribution station, located in Cochrane, Ontario. This distribution station includes two (2) 10 MVA, 115/25 kV transformers (T3 and T4), which feed both East and West 25 kV distribution systems within the Town of Cochrane. There are also six (6) single phase 115/2.4 kV transformers which are used to feed both East and West 4.16 kV feeders within the Town of Cochrene. This report is prompted by a feasibility study performed by McMillan Distribution Engineering Consulting and Brian Smith; in this feasibility study, they outline that the increase in industrial load on the 25 kV system in addition to the loads on the 4.16 kV systems, which are planned to be brought to the 25 kV systems, will result in an overloaded condition where T3 or T4 will not be able to safely supply power to the Town of Cochrene. This report outlines the consequences of inaction and outlines various paths forward which aims to eliminate the risk to the Town of Cochrane's distribution system.

Background Information

Transformers T3 and T4 were installed in 1975. All 4.16 kV systam transformers on site were installed prior to T3 and T4; their nameplates outline fabrication dates ranging from 1953 to 1960. There is an existing plan to eliminate the 115 kV to 4.16 kV transformers within the Cochrane distribution station; this load is to be transferred to the 25 kV system via 25 kV to 4.16 kV transformers. Please see below for a table of the load forecast information obtained from the feasibility study prepared by McMillan Distribution Engineering Consulting and Brian Smith which was shared with 3i0 by Northern Ontario Wires. This table clearly outlines that the peak load of the entire Town of Cochrane will exceed the redundant capacity of the 115/25 kV distribution trensformers, meaning that a failure on either of the 115 kV to 25 kV during a peak period will cause an overload on the remaining transformer.

		Historical Data (kVA)					Near Term Forecast (kVA)					Medium Term Forecast (kVA)				
Season	Annual Growth %	2018*	2019	2020*	2021	2022	2023**	2024***	2025	2026	2027	2028	2029	2030	2031	2032
Summer	0%	11482	10466	11629	11411	10959	12129	12629	12629	12629	12629	12629	12629	12629	12629	12629
Summer	0.5%	11482	10521	11629	11411	10959	12190	12753	12817	12881	12945	13010	13075	13141	13206	13272
Summer	1.0%	11482	10521	11629	11411	10959	12250	12878	13007	13137	13268	13401	13535	13670	13807	13945
Winter	0%	13583	13107	12387	12493	12962	14083	14583	14934	14934	14934	14934	14934	14934	14934	14934
Winter	0.5%	13583	13107	12387	12493	12962	14153	14727	14800	14874	14949	15023	15099	15174	15250	15326
Winter	1%	13583	13107	12387	12493	12962	14224	14871	15020	15170	15322	15475	15630	15786	15944	16103

Table 1: Town of Cochrane Load Forecast

"Thermal Overload Protection of Power Transformers - Operating Theory and Practical Experience" by Rich Hunt, M.S., P.E. and Michael L. Giordano B.S., P.E. outline that operating above the rated temperature for short periods of time has a significant impact on the loss of life of an oil filled transformer. Below is a table outlining the various transformer loading states and the respective rasulting life based on these temperatures. Datermining exactly where within this teble a transformer may operate depends on many variables such as ambient temperature, cooling methods, the thermal characteristics of the transformer and the amount of overload the transformer is exposed to. However, what is known is that peak loading conditions during the summer months correlate with extreme warm weather, which causes increased temperature of the transformer; as such, a single transformer failure during a peak summer event will result in accelerated aging of the remaining unit. As can be seen, the remaining life is reduced dramatically when operating outside of normal conditions. When the age of the T3 and T4 are considered, it becomes clear that a reduction of the remaining life is a risk to the Cochrane distribution system.

	Normal life expectancy loading	Planned loading beyond nameplate rating	Long-term emergency loading	Short-term emergency loading
Top-oil temperature	105° C	110° C	110° C	110° C
Hot-spot temperature	110° C	130° C	140° C	180° C
Loss-of-life factor	1.0000	6.9842	17.1994	424.9218
Resulting life	65,000 hours	9,307 hours	3,779 hours	153 hours

Table 2: Transformer Life Expectancy vs. Over-Temperature Operation

Safety Concerns

Entry to the 4.16 kV building within the Cochrane DS should be limited to when the system is de-energized due to the buswork mounted low within the building. This building is not a safe environment and provisions must be made to remove it from service.

Environmental Concerns

Being that the existing distribution system is located in close proximity to the Town's water supply, 3i0 Inc. believes that a relocation of the distribution station is necessary to prevent possible contamination from transformer oil.

Recommendations

Being that the 4.16 kV loads (outlined to be 2 MVA during summer peaks) are intended to be brought into the 25 kV system [redacted] it is clear that there will be no redundancy where T3 or T4 will be able to supply power to the Town of Cochrane and its residents. For this reason, we believe it necessary to leave the 4.16 kV system as is until such a time that the 25 kV system can be fed by a transformer capable of supplying the entire load within the distribution system. The oil within T3 and T4 should be tested to get an understanding of the oil and insulation condition within the transformers. We recommend the construction of a new distribution station with new equipment to ensure reliable operation of the Cochrane distribution station. In the short term, we believe two new 115/25 kV transformers capable of individually providing power to the Town of Cochrane should be ordered for the new distribution station with an added benefit of having a spare transformer in the event of a catastrophic failure of T3 or T4 prior to the completion of the new station construction. Please see below a summary of our recommendations to work towards removing the aged equipment from service while limiting the risk to the Cochrane distribution system.

<u>New Distribution Station</u>

1. Find suitable land to build a new distribution station in proximity to the 115 kV A4H line; the corner of 5th Street and Western Avenue may be a suitable location. Planning a new distribution station has the following advantages:
    a. Reduces likelihood of contaminated bodies of water from transformer oil spills, where a failure of a transformer could lead to significant contamination.
    b. Entirely greenfield installation allows for normal operation of the Cochrane distribution system up until a point that everything is commissioned and ready for service, minimizing the required outage time.
2. Work with HONI/IESO for the logistical aspects of a new distribution station which will connect to the A4H or A5H 115 kV line. This includes:
    a. Filling out a Confirmation of Verification Evidence Report (COVER) form for Hydro One and;
    b. Completing System and/or Customer Impact Assessments (SIA/CIA) as required by the IESO regarding the new connection
3. Design, build and commission a new distribution station which will house new 115/25 kV transformers, new HV/MV switchgear and protection buildings.
    a. Transformers are to be rated to ensure reliable, safe operation during peak conditions with a single transformer out of service
    b. Switchgear to be configured such that a loss of a single transformer does not interrupt service to 25 kV customers
    c. Transformer, bus and feeder protections to be designed and implemented to isolate and protect the equipment from fault conditions.
    d. Connect new 25 kV feeders to the existing east/west 25 kV feeders; cost will vary depending on the final location for the new distribution station
4. Isolate the existing T3 and T4 transformers from the grid and transfer the load to the new 25 kV switchgear feeders
5. Work to incorporate the 4.16 kV feeders into the 25 kV system through the use of new 25/4.16 kV transformers.
    a. Once the new transformers are in service, all 4.16 kV system loads can be removed from the existing 115/4.16 kV transformers and transferred to the 25 kV system.

Conclusion

The anticipated load increase within the Town of Cochrane and the planned removal of the 4.16 kV transformers within the Cochrane MTS will lead to increased risk of overload to T3 and T4, which compromises the Cochrane distribution system.The close proximity of the Cochrane MTS to the town's water supply and the fact that the 4.16 kV building has exposed buswork mounted at low levels is a significant concern which does not meet modern installation practices. If a single transformer (T3 or T4) failure occurs, damaging currents will flow into the faulted transformer, where its high side fuses are expected to open rapidly. The remaining transformer is likely to feed the fault via the low side connection for a duration which is dependent on the location of the fault, fuse curve and the available fault current magnitude from the grid. If the magnitude of fault current is significant and the duration of the condition is sustained, damage to the second transformer is possible. This type of failure is likely to contaminate the town's water supply and can cause injury or death to anyone near the equipment at the time of the failure. Internal phase faults can cause significant oil spills surrounding the transformer which can contaminate the Town's water supply. Assuming the remaining transformer is in a condition suitable for operation, the remaining transformer high side fuses can be replaced and it can be brought back online to supply the 25 kV system within the Town of Cochrane. If this failure occurs during warm summer months, there is a significant chance of overload, which limits the remaining life of the transformer. A second failure would render the 25 kV system without power until replacement transformers can be installed.

References

- "Thermal Overload Protection of Power Transformers - Operating Theory and Practical Experience" by Rich Hunt, M.S., P.E. & Michael L. Giordano B.S., P.E.
- "Northern Ontario Wires Feasibility Study - New Transformer Station - Town of Cochrane Service Area" by Brian Smith and McMillan Distribution Engineering Consulting
- Northern Ontario Wires Cochrane MST 25 kV Supply to 4 kV Distribution SystemFeasibility Study Addendum by Brian Smith and Brian McMillan of McMillan Distribution Engineering Consulting

Northern Ontario WIRES Inc.

Appendix A-2

McMillan - Feasibility Study

New Transformer Station

Northern Ontario Wires

Feasibility Study

New Transformer Station – Town of Cochrane Service Area

Date: July 17, 2023

Prepared by:

McMillan Distribution Engineering Consulting and

Brian Smith - Consultant

Background:

Northern Ontario Wires currently has a 115 kV – 25 kV Municipal Transformer station with 2 – 10 MVA transformers with the ability to supply up to 20 MVA during summer peak with the aid of air cooling fans. [redacted] have provided notice that [redacted]. The 4 kV substation within the Cochrane MTS is at end of life with operating 115 kV – 4.16 kV power transformers over 65 years old. The combined load of the 25 kV and 4 kV systems including expected increased loading [redacted] could push overall demand to a new peak of 12.6 – 12.8 MVA. Conversion of loading from the 4 kV system from the 115 kV supply to the 25 kV system would not be practical if one of its 10 MVA transformers were to fail during seasonal peak loading periods. Supply of all the loading (existing 25 kV and 4 kV customers) in Cochrane from the 25 kV distribution system would force Northern Ontario Wires to interrupt customers on the 25 kV system should a failure of the supply to one of its two 25 kV feeders occur during summer peak demand periods.

The purpose of this feasibility study is to:

1.) Provide supporting evidence of the necessity of a new 25 kV Transformer Station, examination of three potential sites and impact to the distribution system through system modelling; and
2.) Cursory examination of alternatives such as modifying the existing Cochrane MTS or non-wires alternatives.

Load Forecast

Northern Ontario Wires provided its load forecast data to the IESO for system planning purposes stating the summer and winter MW demand for the Cochrane TS. This load forecast took a conservative approach indicating a 0% annual load growth over a 10 year period. Near term and 10 year projected Summer peak demand was 10.2 MW and winter was 11.8 MW. Using a system power factor of .9 the estimated summer peak demand in MVA is 11.3 MVA and winter peak 13.1 MVA.

Due to the fact the 115 kV – 4 kV substation is a fully depreciated critical infrastructure well beyond its life expectancy the load forecast combines loading of both the 25 kV and 4 kV loading in order to evaluate future capacity needs based on a 25 kV supply scenario. Using system metering data for the 4 kV and 25 kV systems a historical coincidential peak demand and 10 year load forecast using projected demand increase information and various load growth scenarios was completed and found in Table 1 below.

Table 1 – Town of Cochrane Load Forecast

Combined 4 kV and 25 kV Distribution System Peak Load Forecast - Town of Cochrane

		Historical Data (kVA)					Near Term Forecast (kVA)					Medium Term Forecast (kVA)				
Season	Annual Growth %	2018*	2019	2020*	2021	2022	2023**	2024***	2025	2026	2027	2028	2029	2030	2031	2032
Summer	0%	11482	10466	11629	11411	10959	12129	12629	12629	12629	12629	12629	12629	12629	12629	12629
Summer	0.5%	11482	10521	11629	11411	10959	12190	12753	12817	12881	12945	13010	13075	13141	13206	13272
Summer	1.0%	11482	10521	11629	11411	10959	12250	12878	13007	13137	13268	13401	13535	13670	13807	13945
Winter	0%	13583	13107	12387	12493	12962	14083	14583	14934	14934	14934	14934	14934	14934	14934	14934
Winter	0.5%	13583	13107	12387	12493	12962	14153	14727	14800	14874	14949	15023	15099	15174	15250	15326
Winter	1%	13583	13107	12387	12493	12962	14224	14871	15020	15170	15322	15475	15630	15786	15944	16103

Notes: * 2020 Historical Summer Peak and 2018 Winter Peak is used as the base for the Near Term Forecast.

** Additional expected demand from [redacted]

*** Additional expected demand from [redacted]

Influences to Increases to Load Forecast:

Major contributions to increases to summer peak demand are the adoption of air conditioning as average and peak daily temperatures increase and the influence of decarbonizing transportation through adoption of electric vehicles (EV's) or the more practical application for northern climates plug in electric hybrids (PHEVs).

The federal government announced an initiative Dec 21, 2022 regarding the sale and availability of zero emissions vehicles as follows:

> "The regulations will require that at least 20 percent of new vehicles sold in Canada will be zero emission by 2026, at least 60 percent by 2030, and 100 percent by 2035. These targets will help increase supply so that more Canadians who want a ZEV can buy one."

[1]"Projected demand in Ontario from the electrification of cars, buses, trucks and trains is forecasted to grow an average of 20 per cent a year over the next two decades. The impact of electric vehicles on the grid is expected to be felt particularly strongly from 2030 onward as the effects of federal electrification policies kick in."

The 1.0% per year increase scenario for summer and winter peak demand aligns to the projected 20% increase in demand over 20 years published in the IESO "Future of Electricity Demand in Ontario" article published Dec 7, 2021.

Impact of Conservation and Demand Management

The Town of Cochrane summer electrical peak demand of 10.4 MW represents 0.004% of the estimated 2023 provincial summer peak demand (24,900 MW). Figure 1 below shows the estimated contributions of the 2021 – 2024 CDM Programs to peak demand. For example in 2023 the CDM Framework is to deliver approximately 200 MW of demand reduction which when converted to local impact is only 104 kVA using an estimated power factor of 0.9.

[1] The Future of Electricity Demand in Ontario – IESO Article, December 7, 2021

***Figure 1 – 2021 – 2024 CDM Framework Programs Forecasted Provincial Demand Savings*[2]**

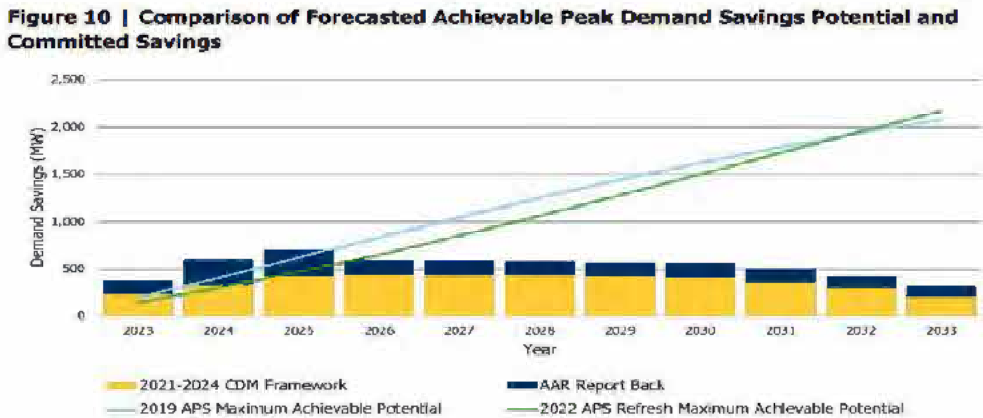


Table 2 illustrates an estimate of annual demand savings attributed to 2021 – 2024 CDM Programs which are not impactful enough to allow supply from a single 10 MVA transformer during summer peak periods.

Table 2 Estimated Impact of provincial CDM Programs

Load Forecast Net of Estimated CDM Program Savings

		Near Term Forecast (kVA)					Medium Term Forecast (kVA)				
Season	Annual Growth %	2023**	2024***	2025	2026	2027	2028	2029	2030	2031	2032
CDM		104	130	208	208	208	208	208	208	156	104
Summer	0%	12025	11999	11921	11921	11921	11921	11921	11921	11973	12025
Summer	0.5%	12086	12060	11982	11982	11982	11982	11982	11982	12034	12086
Summer	1.0%	12147	12121	12043	12043	12043	12043	12043	12043	12095	12147
Winter	0%	14330	14304	14226	14226	14226	14226	14226	14226	14278	14330
Winter	0.5%	14402	14376	14298	14298	14298	14298	14298	14298	14350	14402
Winter	1%	14474	14448	14371	14371	14371	14371	14371	14371	14422	14474

Notes: 2020 Historical Peak was used as the base for the Near Term Forecast.
** Additional expected demand from [redacted]
*** Additional expected demand from [redacted]

Currently [redacted] are participants in the IESO Industrial Conservation Initiative (ICI). By lowering their peak demand during Ontario peak events they can lower their annual electricity costs through a peak demand factor which is used to adjust monthly global adjustment charges to ICI participants. What this means for Northern Ontario Wires is that for a 1 hour period these 2 large customers are attempting to shut down as much load as possible for at least 5 times a year or more when these 5 Ontario peak demand periods are predicted. The 5 Ontario system peaks have typically occurred in Summer months. For every 1 MW of peak shaved it could result in a

[2] 2021 – 2024 Conservation and Demand Management Framework Mid Term Report – December 2022

savings of $500,000 for participants in the ICI. Tables 3 and 4 are the peak shaving results impacting Cochrane MTS through participation in the 2022 ICI program during the 5 Ontario Peaks.

Table 3 [redacted] Load Shed for 2022 ICI Program

[redacted] Load Shed 2022 ICI Program							
Date of Peak Event	Day of Week	Hour of Peak	Peak Load Hour Prior	Peak Load During	Peak Load Hour After	Amount Shed	Comment
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 4 [redacted] Load Shed for 2022 ICI Program

[redacted] - 2022 ICI Participation Results						
Date of Peak Event	Hour of Peak	Peak Load Hour Prior	Peak Load During	Peak Load Hour After	Amount Shed	Comment
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

It can be concluded that through price or cost of power signals these customers attempt to shed load in order to reduce their annual electricity costs. The most coincidental load shed in 2022 was [redacted] on June 22nd. This load shed of [redacted] does not completely eliminate all load at the facilities but is an indicator of what could be accomplished by working with these customers to reduce load during emergency conditions such as a single transformer or feeder supply contingency short term. This would not be a technical solution for a long duration outage. The current supply configuration to [redacted] separates their load between the F4 and F5 circuits. In order to back up the F4 circuit to the F5 [redacted].

Industrial Load Impacts:

Electrical peak demand from [redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

Impact of Extreme Temperatures on Load Forecast

When examining the coincidence of summer and winter peak demand events to temperature extremes it can be concluded that extreme temperatures are a factor contributing to peak events.

Extreme temperatures would be defined as temperatures that exceed the seasonal average levels refer to Appendix B as it relates to a peak demand event. For the purposes of this report and analyzing the data in Table 3 we define the parameters for extreme temperatures as follows:

Summer extreme threshold is >24 Deg C.
Winter the threshold is <-23 Deg C.

Table 5 below indicates the coincidence of extreme temperatures to Cochrane MTS peaks. Extreme hot summer weather averaging over 30 Deg C will reduce the permissible transformer loading to less than 100% of the nameplate rating. From 2018, 2020 and 2021 the temperature at peak summer load was 29 Deg C and with trends of increased extreme weather events overloading a single 10 MVA transformer would reduce the life expectancy. At an average temperature of 25 Deg C the permissible load of a 10 MVA transformer is 105% or 10.5 MVA. The historical hourly weather data for the summer peak day of July 4, 2018 indicated the temperature exceeded 25 Deg C threshold. All historical summer peak events would have exceeded the 105% permissible transformer rating of a single 10 MVA transformer if the average daily temperature would have climbed to >25 Deg. C.

Table 5 – Historical Peak Load Event Summary

Historical Coincidental Peak Loads Summary

Year	Season	Date	Time	kW	KVAR	Calculated KVA	Temperature	Extreme Temp Y/N	System Peak Power Factor
2018	Summer	04/07/2018	12:00	9454	6771	11629	29	Y	0.81
	Winter	18/01/2018	1230	11967	6771	13750	-9	N	0.87
2019	Summer	18/07/2019	1200	9431	4663	10521	23	N	0.90
	Winter	31/01/2019	1045	12001	5825	13339	-25	Y	0.90
2020	Summer	30/06/2020	1145	10464	5071	11629	29	Y	0.90
	Winter	15/12/2020	1015	11519	7839	13934	-24	Y	0.83
2021	Summer	18/08/2021	1600	10254	5008	11411	29	Y	0.90
	Winter	22/12/2021	1700	11639	5008	12671	-18	N	0.92
2022	Summer	17/08/2022	1315	9510	5445	10959	27	Y	0.87
	Winter	26/01/2022	1730	12053	5611	13295	-13	N	0.91

Forecasted summer peak load net of CDM for 2023 is estimated at 12 MVA well above the permissible loading of a 10 MVA transformer during summer months. Table 6 below illustrates permissible loads at various daily average temperatures along with required load mitigation options during the summer peak for a single 10 MVA transformer contingency option.

Table 6 – 2023 Forecast Summer Peak Permissible Loading and Load Shed Requirements

Season	Calculated Peak Demand kVA	24 Hour Average Air Temp. Deg. C	Permissible Load in % of Rated kVA	Permissible Transformer Loading 10 MVA (kVA)	Potential Load Shed Required kVA	Estimated 4 kV Substation Summer Peak Load	Reserve Capacity
2023 Summer net of CDM	12025	20	105	10500	1525	1763	238
2023 Summer no CDM	12129	20	105	10500	1629	1763	134
2024 Summer no CDM	12629	20	105	10500	2129	1763	-366

By Summer of 2024 when all the additional industrial load is added there will not be enough reserve capacity to supply the existing 4 kV onto the 25 kV system in a single 10 MVA transformer contingency scenario. Other options to meet demand would be to dispatching customers to shed load or operate standby emergency generators.

As average summer daily temperatures increase and peak daily temperatures stay >25 Deg C a forecasted growth in summer peak demand due to customers installing air conditioning is a reasonable assumption. Table 1 uses a growth rate of both .5% and 1% in the summer and winter load forecast for comparison purposes to the single 10 MVA transformer contingency strategy.

System Power Factor & Peak Load Events

Further to the data in Table 3 the industrial loads have a major contribution to the peak demand events as indicated by the power factor of the system load being very low. Power factor correction for the large industrial customers would reduce the kVA demand and improve the efficiency of the distribution system. [redacted].

Alternative Transformer Station Site Selection:

Given that the majority of industrial load that drives peak demand is in the east area of the town two east end sites were selected by NOW to examine based on the availability of town owned property. However availability of privately owned transmission circuits in the proximity of the two east sites selected another west site near the HydroOne A4N transmission circuit was selected.

NOW advised us that future plans prefer the existing Cochrane MTS site be decommissioned and all oil filled equipment removed from the site which is located next to the Town of Cochrane water supply.

Below is a map of the three proposed transformer station locations recommended by Northern Ontario Wires at the time of this study.

Figure 2 – Proposed Transformer Station Sites

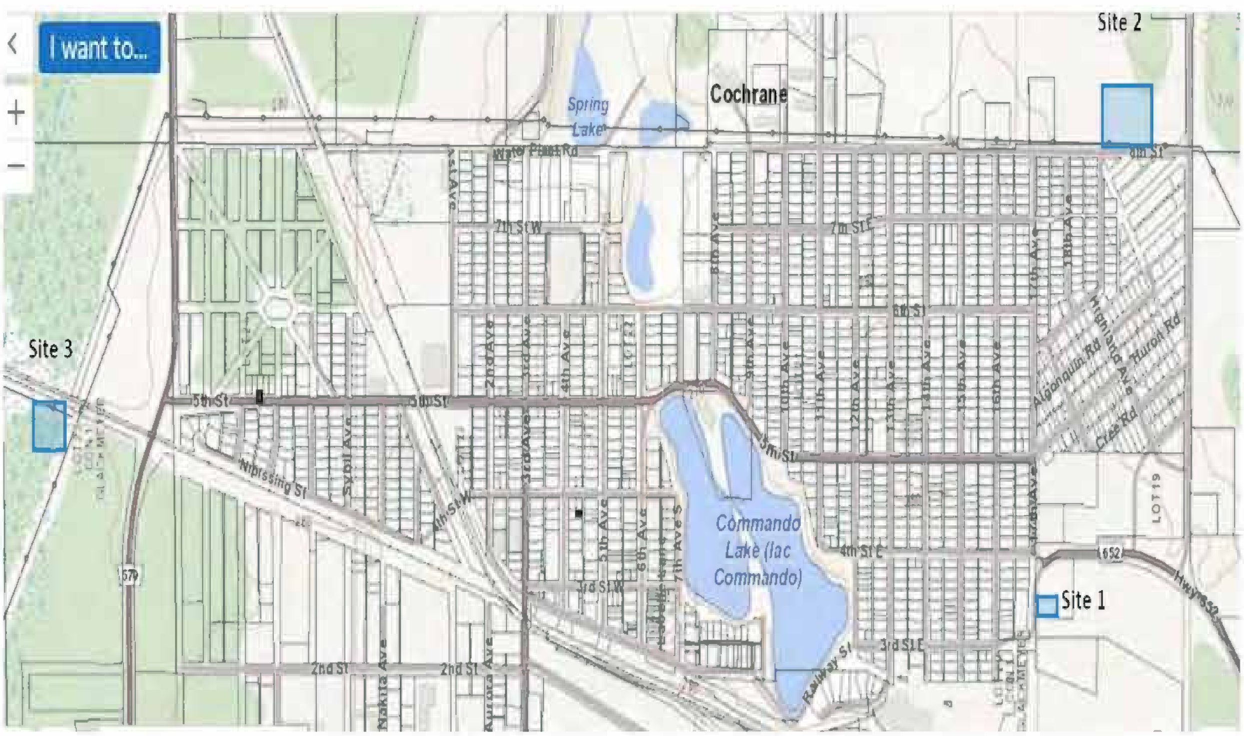


Figure 3 Transformer Station Site 1`

Pros:

- Very close proximity to 115 kV HydroMega transmission supply.
- Proximity to create an east and west 25 kV feeder tie point.
- Distribution costs would be $200k less than Site 2 option.
- Site property is already owned by the town of Cochrane and preliminary discussions indicate it would be a feasible location if approved by the town.
- Closest proximity to the 2 largest industrial customers.

Cons:

- 115 kV transmission supply is currently owned by HydroMega requiring permission to connect, connection contributions or a HydroMega transmission license application.
- Building a 25 kV distribution tie line through the Industrial customer property would require easements and possibly underground construction.

Class 4 Estimate:

- Distribution Line Extension Costs ~ $75,000
- Station Design and Construction Costs: ~ $5.0 - $8.0 M pending final design
- Property Costs or land agreements TBD
- Connection costs to HydroMega transmission line TBD

Figure 4 – Proposed Transformer Station Site 2

Pros:

- Close proximity to H2O owned 115 kV transmission supply.
- Proximity to existing station.
- Site property is vacant would have to be obtained if it isn't already owned by the town of Cochrane.

Cons:

- 115 kV transmission supply is currently owned by H2O requiring OEB permission to connect, connection contributions or a transmission license application.
- Further distance to create an east and west 25 kV feeder tie point increased distribution connection costs by ~ $200k
- Building a 25 kV distribution tie line through the Industrial customer property would require easements and possibly underground construction.

Class 4 Estimate:

- Distribution Costs - $310k
- Station Design and Construction Costs: ~ $5.0 - $8.0 M pending final design
- Connection costs to H2O owned transmission circuit – TBD
- Property Cost TBD

Figure 5 – Proposed Transformer Station Site 3

Pros:
- Connection to the Hydro One transmission system is the most practical compared to the Hydro Mega and H2O owned transmission systems.
- Close proximity to Hydro One owned 115 kV transmission supply.
- Site property is vacant and owned by the Town of Cochrane.
- Site is adjacent to an existing right of way should Northern Ontario Wires wish to construct a dedicated express feeder to supply only the wood mill customers.
- Potential for connection of HydroMega embedded generation in the east end could support the distribution system load.
- Balancing of load is easily accomplished between two feeders from Site 3 once Cochrane MTS is retired.

Cons:
- Balancing load between the existing Cochrane MTS and the proposed Transformer Station Site 3 is not ideal when compared to Sites 1 or 2. Refer to Distribution System Optimization Figure 11
- [redacted]
- [redacted]

Class 4 Estimate:
- Distribution Costs - $50 - $100k
- Station Design and Construction Costs: ~ $5.0 - $8.0 M pending final design
- Property Cost TBD
- Hydro One Costs to extend the 115 kV connection to the A4N circuit. TBD

Timing Considerations:
- Station property acquisition or easement agreements – 1 year or more lead time.
- Hydro One Transmission Build 1 – 3 Year lead time

- New Station needs an IESO System Impact assessment – 1 Year Application Process
- New Station costs would be part of the Distribution System Plan submitted with the 2025 Cost of Service Rate Application.
- Power transformer delivery lead time 18 plus months.
- Design build request for proposal process 3 - 6 months
- Transmission License application lead time 1 year or more.

Urgency Factors:

- [redacted]
- Proposed 25 kV - 4 kV transformation installation is under review and would potentially transfer up to 2.0 MVA of summer peak load being transferred to the 25 kV system.
- A single 10 MVA transformer could not manage total summer peak demand (11.6 MVA currently and 12.6 MVA by 2024) should one of the 48-year-old transformers or feeder cables fail.

New Station Design Requirements:

Further to feasibility of a new Transformer Station there will be modern design requirements that involve increased construction and ongoing operating costs:

New stations must meet the applicable Market Rules for monitoring and operating a Transformer Station. The type of operating requirements would include at a minimum 24/7 monitoring and the provision to share analog and status data with the IESO and rapid interruption capability within 10 minutes. To facilitate this a Supervisory Control and Data Acquisition System is required which can be purchased and monitoring services provisioned through a third-party service contract with another LDC.

Notes on Connecting a New Transformer Station and Distribution System Modelling and Configuration:

For the purposes of modelling a proposed new Transformer Station the following assumptions were used:

- Single 16 - 20 MVA OA/FA transformer 115 kV - 25 kV with an impedance of 8 %
- Two new 25 kV feeder exits from each proposed Site will have open points to the existing F4 East and F5 West 25 kV feeders.
- Each Feeder to have an electronic recloser and 350 MCM Cu feeder exit for single contingency and future load growth.
- All references to loading in Amps is for the highest phase current reading of the identified feeder.
- Simulations of the proposed Sites without Cochrane MTS were conducted as well.
- All load flows were based on winter peak conditions using -25 Deg C. and timing of 17:00 hours.

Load flow analysis and system optimization simulations were conducted for each of the 3 proposed Site locations.

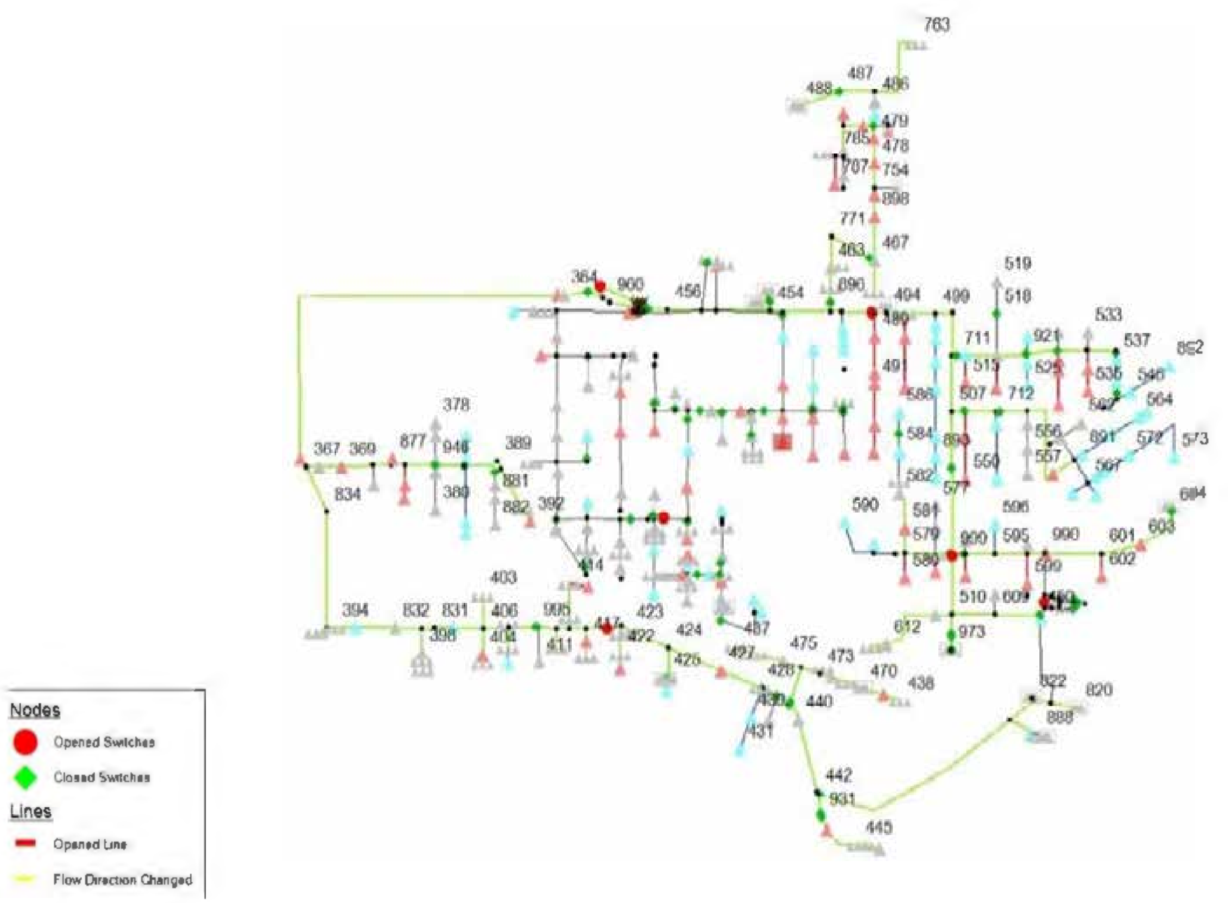
The purpose of the simulations with the DESS model is as follows:

1. Determine if balancing of the load between a new proposed station Site location and the existing Cochrane MTS could be accomplished.

2. Determine if any potential voltage problems are created if the Cochrane MTS was to be decommissioned.
3. Model minor system adjustments like additional switches or line segments as part of the optimization of load balancing.

The following are comments related to the Figures 6 to 12 which are snap shots derived from the modelling results for the 3 proposed Transformer Station sites.

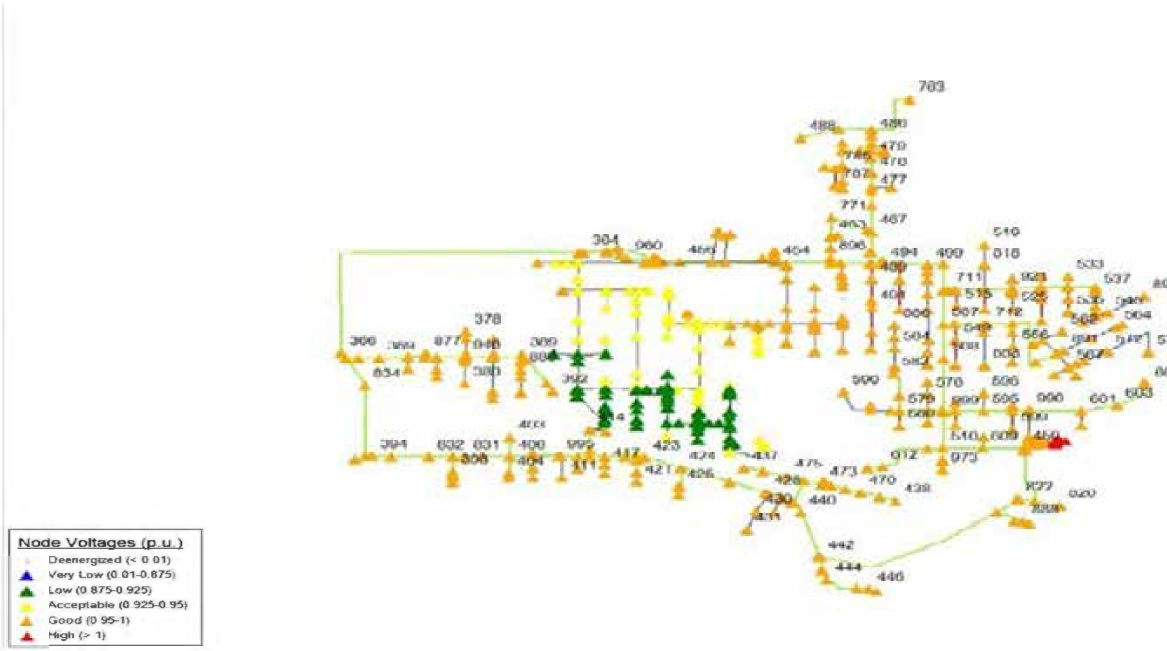
Figure 6 – Site 1 Distribution System Optimization – Existing Cochrane MTS and Proposed Site 1 Transformer Station



Note that new locations for 3 phase gang operated or line opener switches would be required to establish new optimal open points for operating the existing Cochrane MTS and new Site 1 TS sources. Approval to connect to the HydroMega 115 kV Transmission circuit along with an OEB approved Transmitters License for HydroMega is required prior to any connection. As per Figure 6 above this simulated configuration, 3 feeders have 80 amps or less while the fourth feeder supplying the wood mills would have 130 Amps typical being very close to achieving balance on the 4 feeders under peak load conditions.

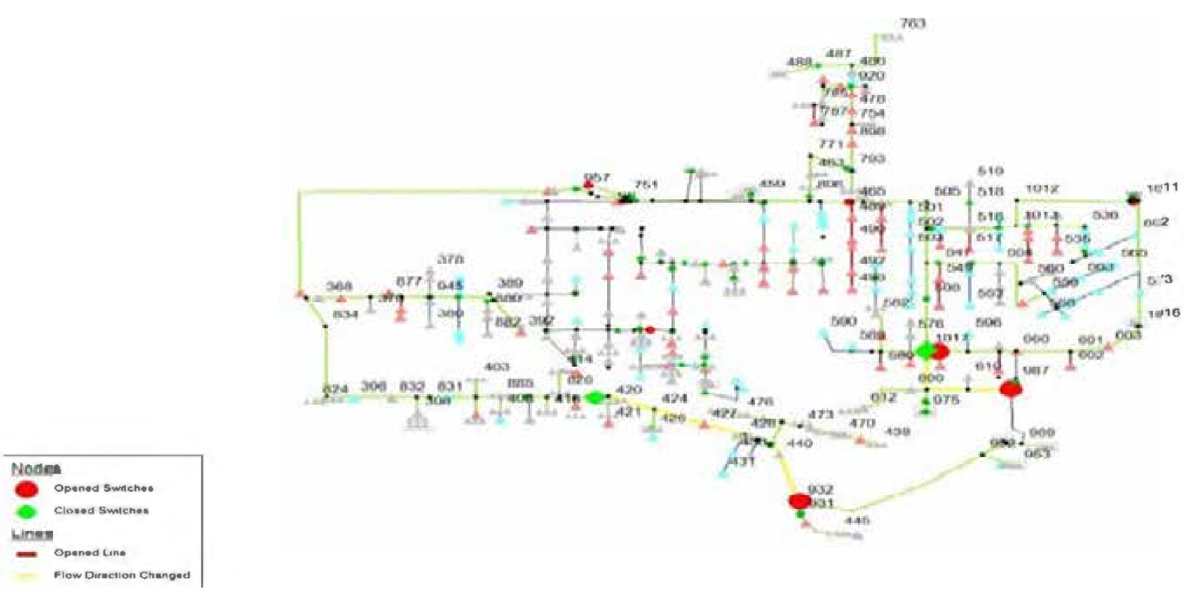
Site 1 option in conjunction with the existing Cochrane MTS would allow a good balance of the supply to the town using 4 interconnected feeders with open points.

Figure 7 – Site 1 Load Flow for New TS Without Cochrane MTS



As per the load flow simulation in Figure 7 using the New TS Site 1 there are not any abnormal voltage conditions when the existing Cochrane MTS was removed even with the 4 kV feeders supplied from the 25 kV system.

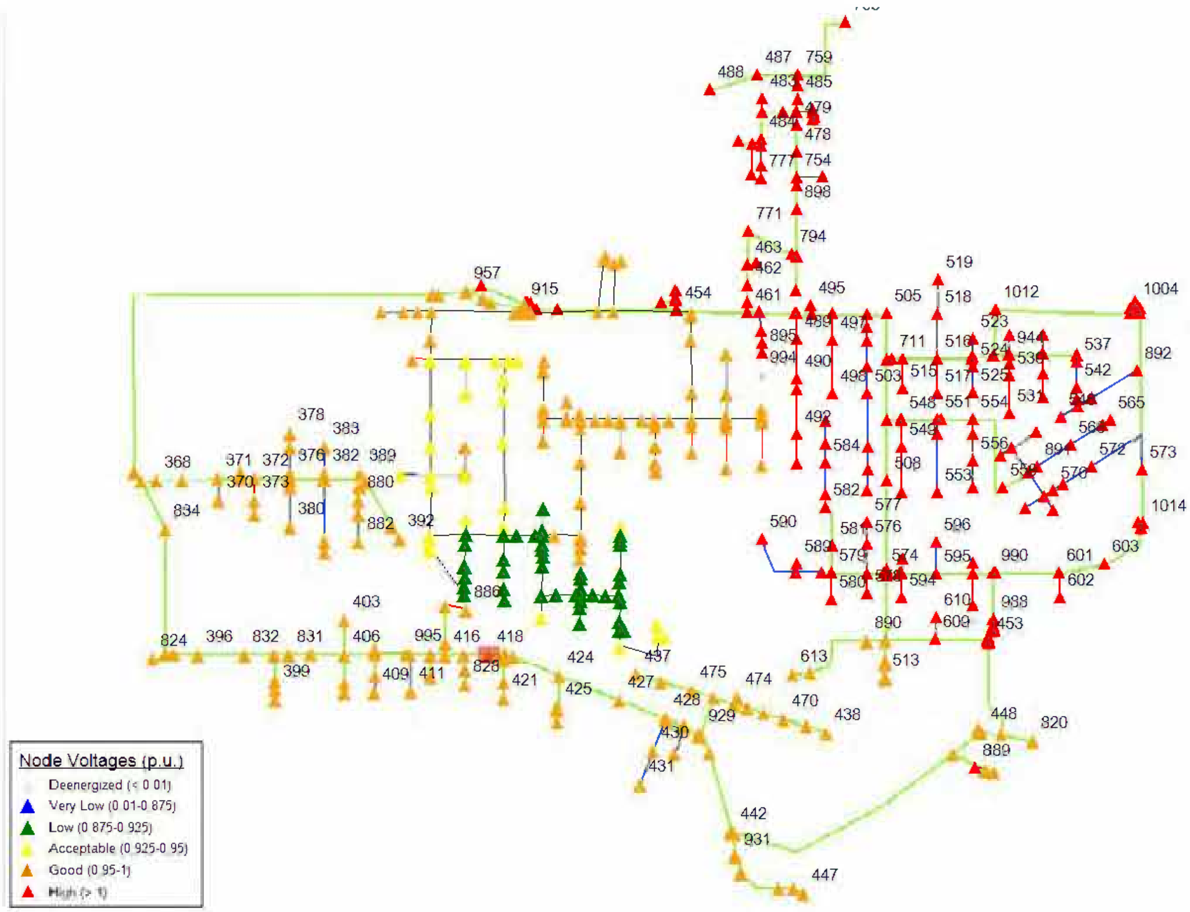
Figure 8 – Proposed New Station Site 2 Distribution System Configuration



Site 2 requires more extensive distribution line construction south along Genier Road and also west on Eighth Street to tie into the existing 25 kV distribution system. Approval for connection to the H2O owned transmission line and an approved Transmitters License for H2O would be required prior to connection. As with Site 1 new gang operated or line opener switches to establish new open points would be necessary to optimize the supplies from Cochrane MTS and the New TS at Site 2. This simulation in Figure 8 also required [redacted]. As per the results of the system optimization in Figure 8, balancing the load between Site 2 and Cochrane MTS cannot be accomplished due to Site 2 being closer to Cochrane MTS. The Cochrane MTS F4 east feeder and new Site 2 tie feeder has only 20 amps with 30 Amps on the F4. While the F5 west feeder is modeled with 80 Amps and the new TS feeder supplying the wood mills has over 130 Amps.

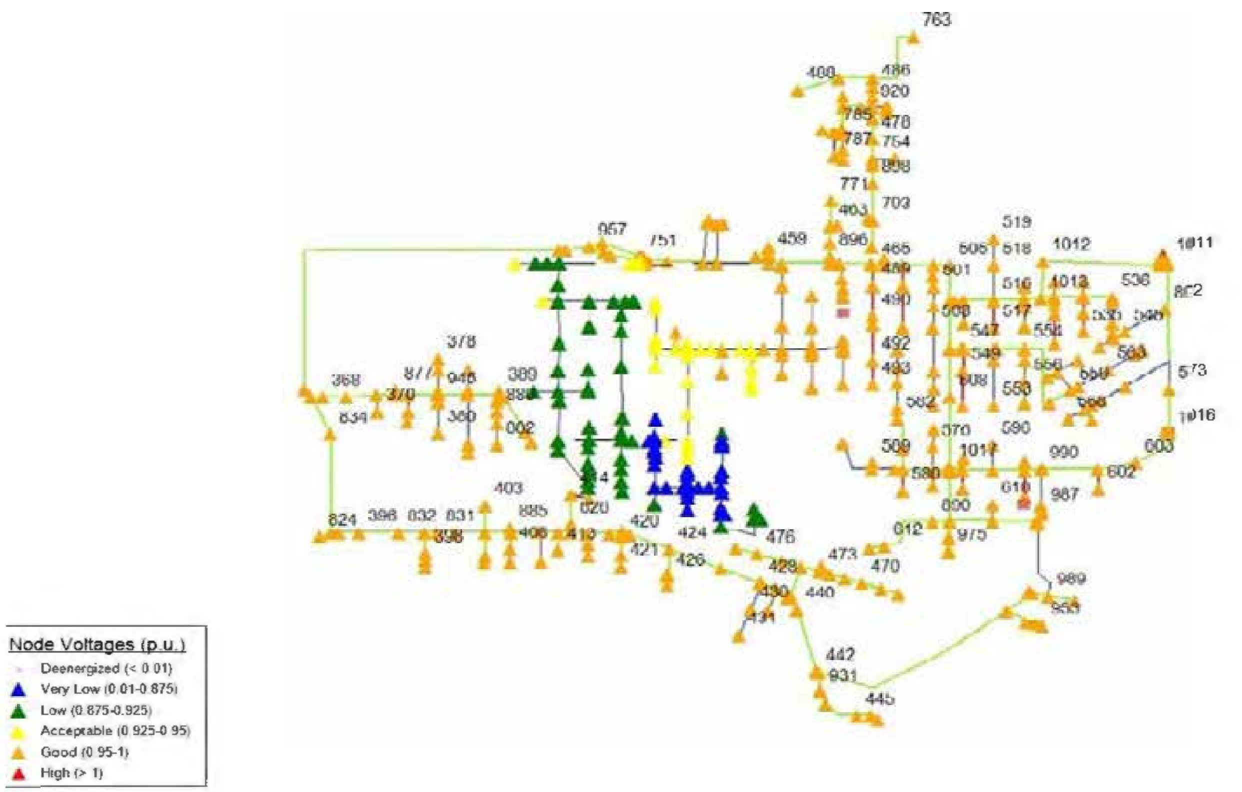
As compared to Site 1, Site 2 is not as desirable for achieving feeder load balancing between the existing Cochrane MTS and a proposed TS at Site 2.

Figure 9 Load Flow Supply Site 2 Simulated Normal Open Points between Cochrane MTS



The load flow result in Figure 9 for Site 2 with Cochrane MTS in service indicates acceptable voltage conditions.

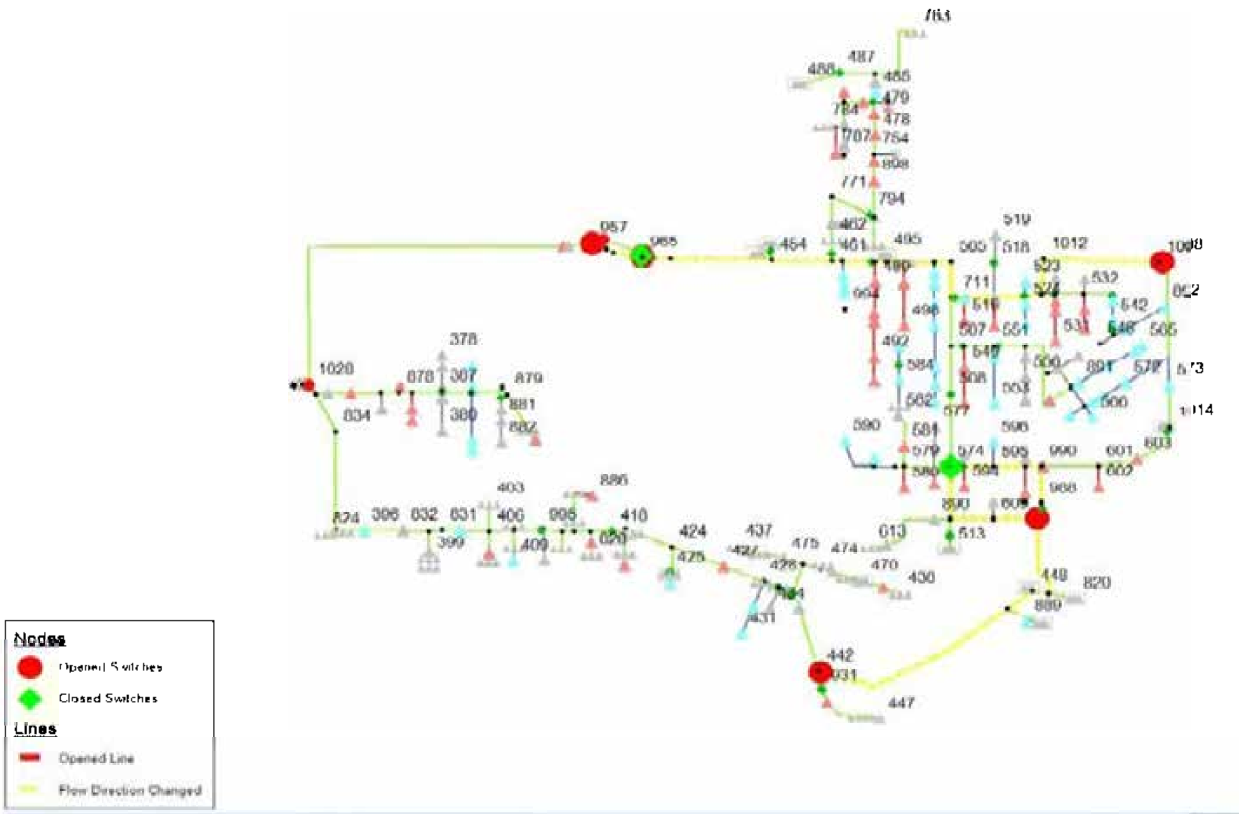
Figure 10 – Site 2 Single Source Load Flow



As per Figure 10 above very low voltage conditions are illustrated on the 4 kV distribution system when a single source (two feeder) supply from the new Site 2 load flow is simulated. The geographic location of Site 2 is the contributing factor to this low voltage condition. The low voltage condition could be overcome through variable voltage tap changers at the new Transformer location or changing taps at the individual distribution transformers.

Based on the results of modelling Site 1 and Site 2 it was determined that Site 1 was preferred over Site 2 based on load balancing and adequate voltage levels under single source scenario.

Figure 11 Site 3 Distribution System Optimization with the Existing Cochrane MTS



For Site 3 optimizing the distribution system with the existing Cochrane MTS in order to balance load amongst 4 feeders is not accomplished in the configuration shown in Figure 11. Highest phase current from the configuration modelled in Figure 11 from the two feeder exits at Site 3 had 160 amps for the South feeder and 0 amps for the North feeder as there are no connections to the 25 kV system along Western Avenue and Eighth Street on the circuit going North and East all the way to Cochrane MTS. The Cochrane MTS F4 highest feeder phase current is 133 Amps and F5 has 52 Amps which included all 4 kV system loading.

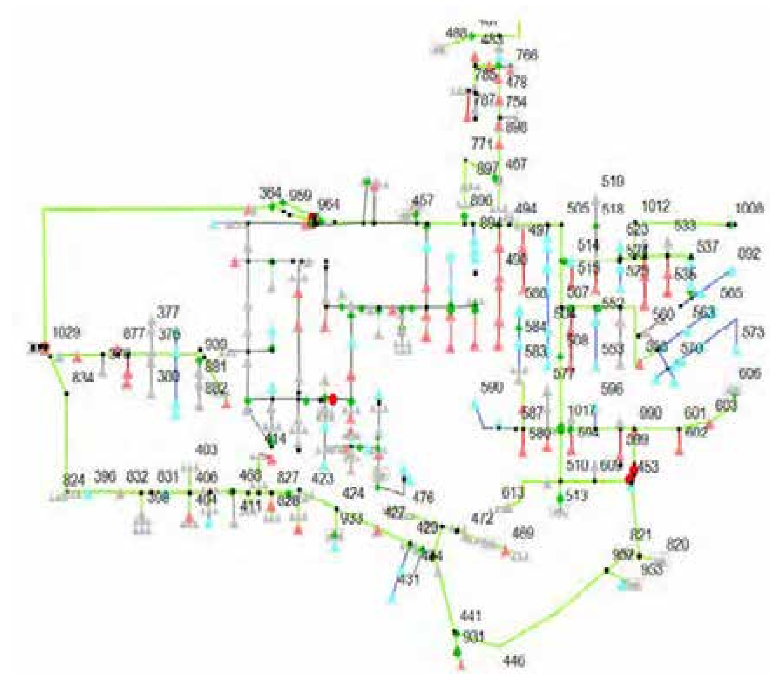
[redacted] would allow for better sharing of load between the Site 3 South feeder and the F4 with phase currents of 114 Amps on F4 and 174 Amps on the South feeder.

A configuration to off load Cochrane MTS and extend the life of the two existing 10 MVA transformers would require [redacted] Balance of all 4 feeders would not be accomplished (South 230 Amps, North 0, F4 69 Amps and F5 52 Amps) but reserve capacity and switching options for the Site 3 North Feeder would allow for a complete outage at Cochrane MTS and a balance between North and South Feeders. All the supply to the 4 kV system would be from the Cochrane MTS F5.

To further offload the 25 kV F4 East Feeder an express feeder could be built through the town along Fifth Street and perform voltage conversion of the 4 kV distribution through the downtown. Another 50 to 100 amps could be added to the North feeder through the express feeder construction. This additional load shed would be discretionary as the same objective could be accomplished through by-pass of the Cochrane MTS 25 kV feeders.

[redacted]

Figure 12 – Site 3 Configuration Without Cochrane MTS



After conducting a load flow as per Figure 12 above without the Cochrane MTS connected and optimizing the North and South feeders from site 3 using a tie line. Simulating winter peak conditions using the Figure 12 configuration produced max phase current of 140 amps on the North Feeder and the South Feeder 180 amps. [redacted]

Figure 12 is a reasonable configuration as there are no voltage issues. Further load balancing can be accomplished by installing new open point switches to balance the load. If voltage conversion of the 4 kV load to the 25 kV system were to be carried out enough capacity would be available from new transformation proposed at Site 3.

Cursory Review of Alternatives to New Transformer Station Considerations

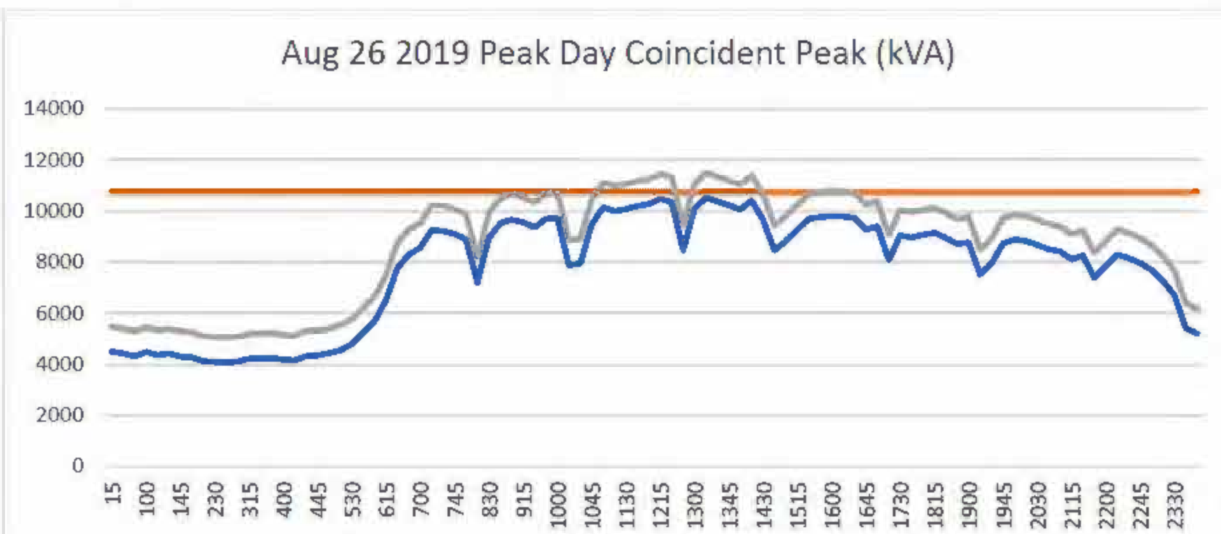
Further to the Ontario Energy Board publishing its Framework for Energy Innovation – A Pathway to DERS Integration published January 2023, local distribution companies (LDCs) must consider non-wires alternatives to traditional wires solutions.

HydroMega has a pending application with the IESO for up to 10 MW of solar PV and is slated to reopen its Cogeneration Facility connected to the 115 kV transmission system as a peak power plant in Q2, 2024. NOW has engaged with HydroMega to discuss how the solar PV system and batteries could be a solution to mitigating summer peak demand and future requirements for a station build. The OEB is to publish an economic model by end of 2023 early 2024 for DERS connections as a non wires alternative. Further discussions with the OEB regarding the incentive mechanism for LDCs and financial arrangements with DERs owners is needed to evaluate if this is a viable solution to offset the needs of a new transformer station. Location of the proposed HydroMega solar PV site is located in the vicinity of the preferred Site 1 transformer station close to the industrial loads.

Any DERS connection would require NOW to perform in depth engineering studies that might result in investments in protection system enhancements such as recloser technology on distribution feeders and possibly a DER management system. Protection enhancements may include transfer trip capability.

Through examination of the Cochrane daily load curves the contributions of industrial process load create drastic swings in peak demand which normally occur weekdays during production cycles as shown in Figures 13 and 14 below:

Figure 13 – Historical Summer Peak Demand Event Profile:



Legend of Curves

Single Transformer Contingency Threshold

[redacted]

Historical Peak Load shape with 4 kV load connected to 25 kV System

Figure 14 – Weekly Summer Peak Load Curve:

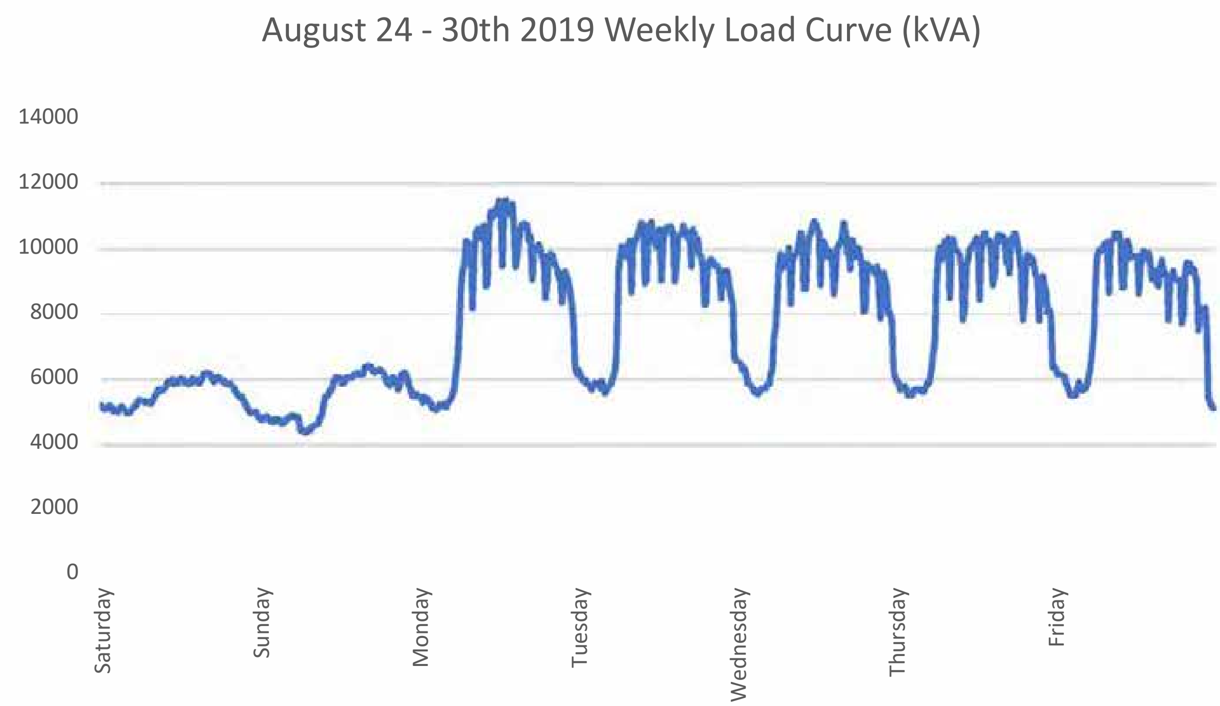


Figure 13 illustrates the historical coincidental (25kV + 4 kV) peak load curve as the blue line with the grey line being the adjusted load curve for the load forecast which includes the additional increase peak load [redacted]. The forecasted grey curve of peak load exceeds the available single transformer and feeder contingency supply from Cochrane MTS.

It can be determined from Figures 13 and 14 weekday load curves that a swing of approximately 2.0 – 2.5 MVA occurs as a result of industrial process loads occurring from 8 am to 5 pm. Aligning this loading to a potential DERS solution would require a reliable daily mitigation of 2.5 MVA from 8 am – 5 pm for those summer peak periods where loading exceeds a single feeder supply contingency.

The HydroMega 10 MW of proposed Solar PV as a resource could align to the expected weekday daytime summer load shape and serve as a feasible non-wires alternative. However, for non-peak hours the 10 MW would provide an excess of power into the distribution system forcing reverse power flow that the Cochrane MTS would need to manage.

Solar PV with 4 MW of battery storage capacity would provide an additional security for reduced daylight availability during peak periods.

[redacted]. Funding of the battery storage could be from the proceeds of the ICI program.

Life Cycle Replacement of Transformers at Cochrane MTS

Another alternative for consideration would be to add another transformer at Cochrane MTS capable of supplying the entire town to allow the eventual replacement of one or both of the existing fully depreciated 10 MVA 1975 transformers at Cochrane MTS which are approaching 48 years old.

Potential distribution system reconfiguration to allow for an express feeder [redacted] or reconfiguration of the existing circuits. The investment in an express feeder [redacted] would be best aligned with additional capacity requirements [redacted]

For the purposes of this study feasibility options for the new transformer station was limited to Sites 1, 2 and 3.

Further detailed modelling of a new transformer at the Cochrane MTS would be recommended to determine the optimal feeder configuration to balance the load amongst the new and existing transformer/s.

Feasibility Study Conclusions:

1. Forecasted summer peak demand for both the 4 kV and 25 kV systems is expected to exceed the capacity of a single 10 MVA transformer contingency scenario.
2. Voltage conversion from the 4 kV to the 25 kV system is not recommended until additional capacity becomes available through the construction of a new TS, suitable DERs connection or reduced summer peak loading on the 25 kV system.
3. The current 25 kV feeder egress cables at Cochrane MTS are beyond life expectancy and if one set of cables fails the remaining set will not be able to supply peak load. The planned upgrade to the 25 kV feeder egress cables will support the expected peak load.
4. The existing metal clad switchgear at the Cochrane MTS is a single source of failure and not readily replaceable. Parts for maintaining and repairing the switchgear are available.
5. The current IESO metering for the 25 kV distribution system has reached end of life.
6. Building a new MTS at Sites 1, 2 or 3 would relieve the single transformer contingency deficiency and provide load growth capability for the long term.
7. Site 3 is preferred location compared to Sites 1 and 2 based on availability of the Hydro One transmission system and results of modelling the distribution system. Site 2 requires much more distribution line construction. Site 3 would require some additional distribution line construction for the North feeder to be able to pick up any load other than emergency conditions based on the existing system configuration. Each site requires installation of new switches to establish normal open points to balance feeder loading.
8. [redacted]
9. The January 2023 OEB directive will require NOW to study non-wires options (Generation, Energy Storage, Demand Response).
10. Further discussion with customers, engineering study and economic evaluation of wires versus non-wires options is required to determine the preferred option for Northern Ontario Wires.

[redacted]

[redacted]

[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
		[redacted]	[redacted]
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[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]
[redacted]	[redacted]	[redacted]	[redacted]

[redacted]

[redacted]

[redacted]

Appendix B – Cochrane Average Weather Data

Cochrane Ontario Average Weather Data

Month	High / Low(°C)	Precipitation (days)
January	-12° / -25°	12
February	-9° / -23°	9
March	-2° / -16°	8
April	7° / -6°	7
May	16° / 2	9
June	21° / 6°	11
July	24° / 10°	11
August	22° / 9°	10
September	15° / 4°	13
October	8° / -1°	11
November	0° / -8°	11
December	-9° / -20°	14

Appendix B

Customer Engagement Survey Results

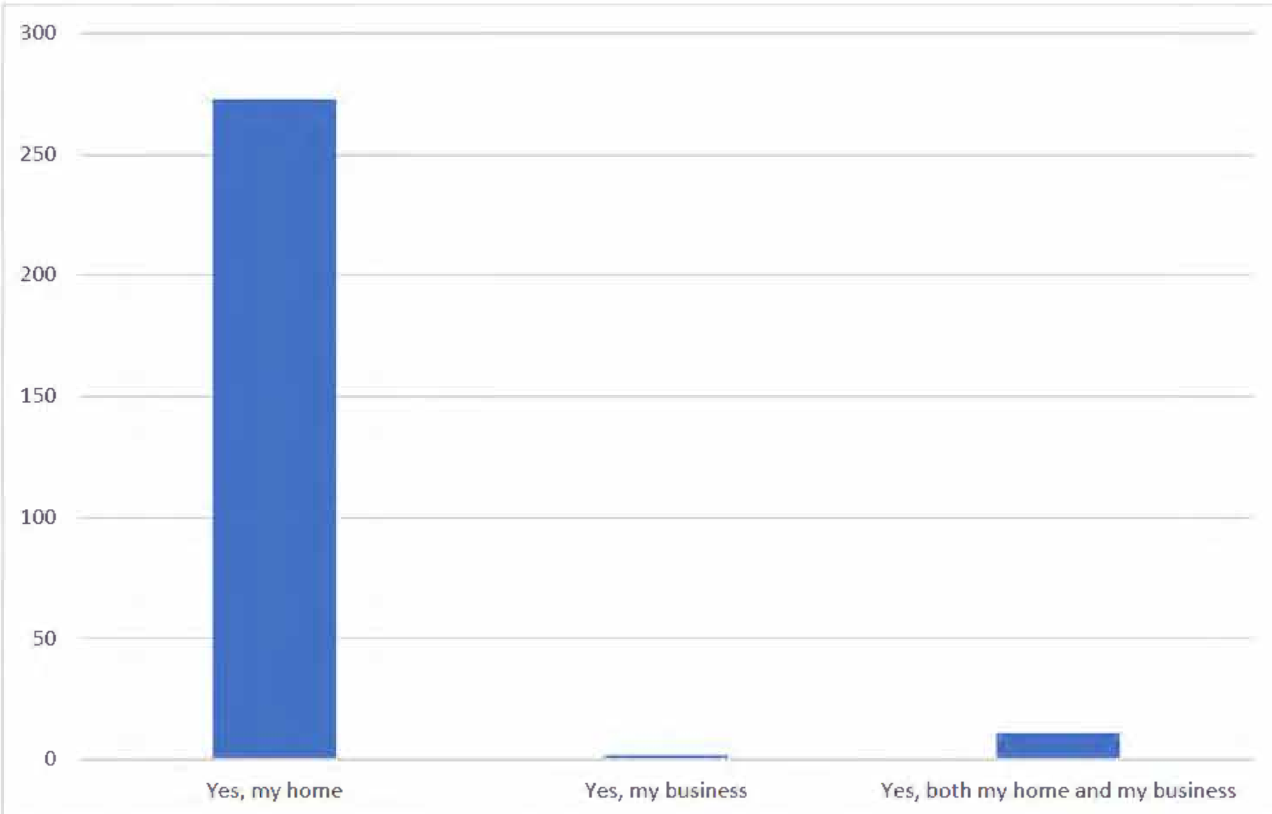
INTRODUCTION

This survey was conducted for the electric customers of Northern Ontario Wires Inc. (NOW) to gauge their satisfaction with the services provided by the company. NOW's Customer Service Department initiated the engagement survey to collect valuable feedback from its customer base. The survey questionnaire was collaboratively designed by BBA and NOW to ensure comprehensive and relevant questions. The survey was actively promoted by NOW through various channels, including their official website and social media platforms, to maximize participation. All responses were gathered online. The survey period was from July 26, 2024, to August 9, 2024, during which customers were invited to complete the questionnaire. This report presents a factual summary of the survey findings, organized by individual questions, offering insights into customer satisfaction and areas for potential improvement.

General

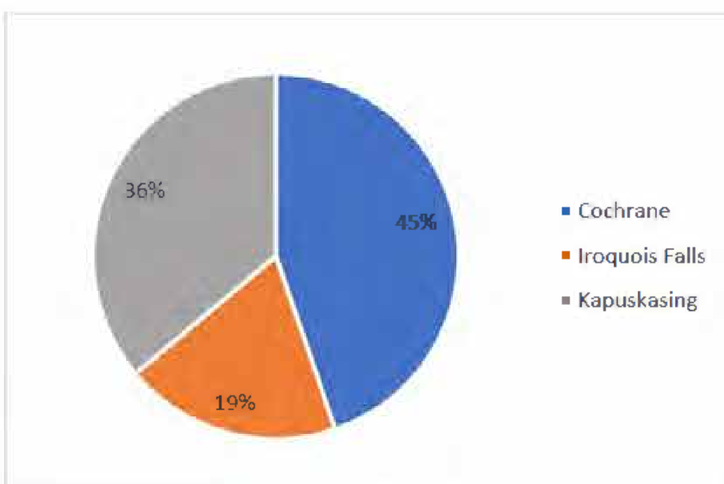
1. Do you pay a Northern Ontario Wires electricity bill for your home or business (including an organization, such as a church)? Please note that only Northern Ontario Wires customers that fill out the survey are eligible for the prize draw.

- Yes, my home
- Yes, my business
- Yes, both my home and my business
- No
- Unsure



The data shows that out of 296 respondents, the vast majority, 273, pay a Northern Ontario Wires electricity bill for their home. A small number, 11 respondents, pay for both their home and business, while only 2 respondents pay solely for their business. representing businesses or dual home-business accounts.

2. Northern Ontario Wires serves three communities (Cochrane, Iroquois Falls, and Kapuskasing). For us to know what community you live in, please let us know what the postal code is for your primary residence, where you live?

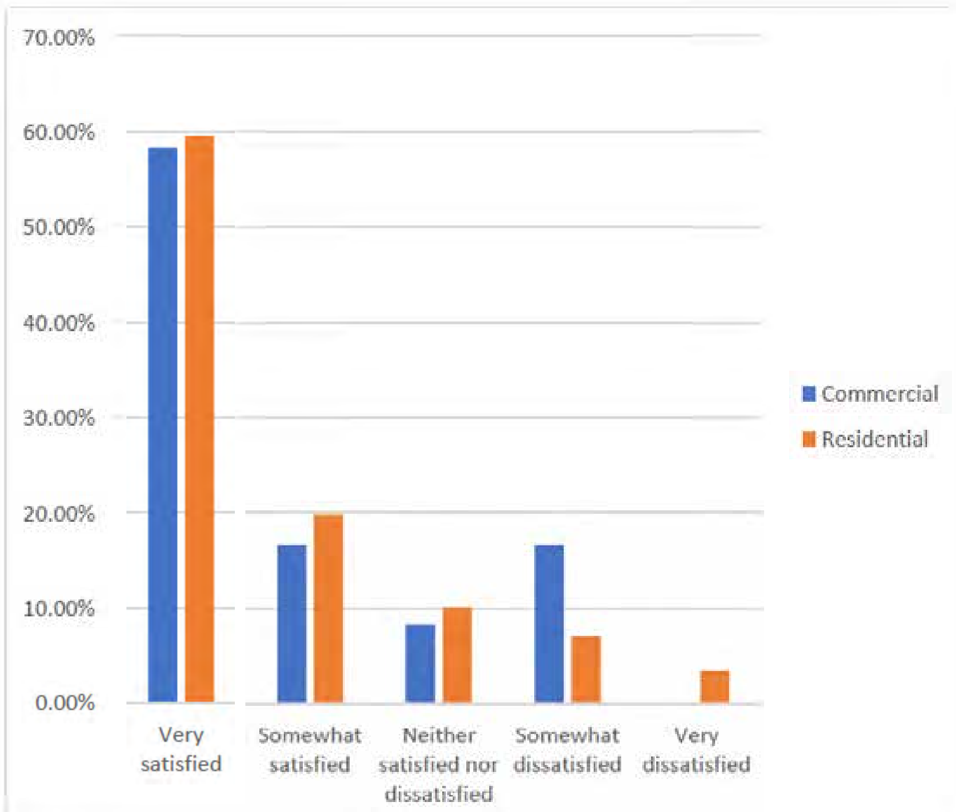


Northern Ontario Wires serves three primary communities, with 266 respondents answering this survey question. The majority of respondents, 119, are from Cochrane, followed by 96 respondents from Kapuskasing, and 51 respondents from Iroquois Falls. This distribution provides a clear view of the representation from each community, which is important for understanding the feedback and needs of customers across different areas served by Northern Ontario Wires.

Overall Performance

3. Overall, how satisfied, or dissatisfied are you with the electricity service from Northern Ontario Wires Inc.?

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied

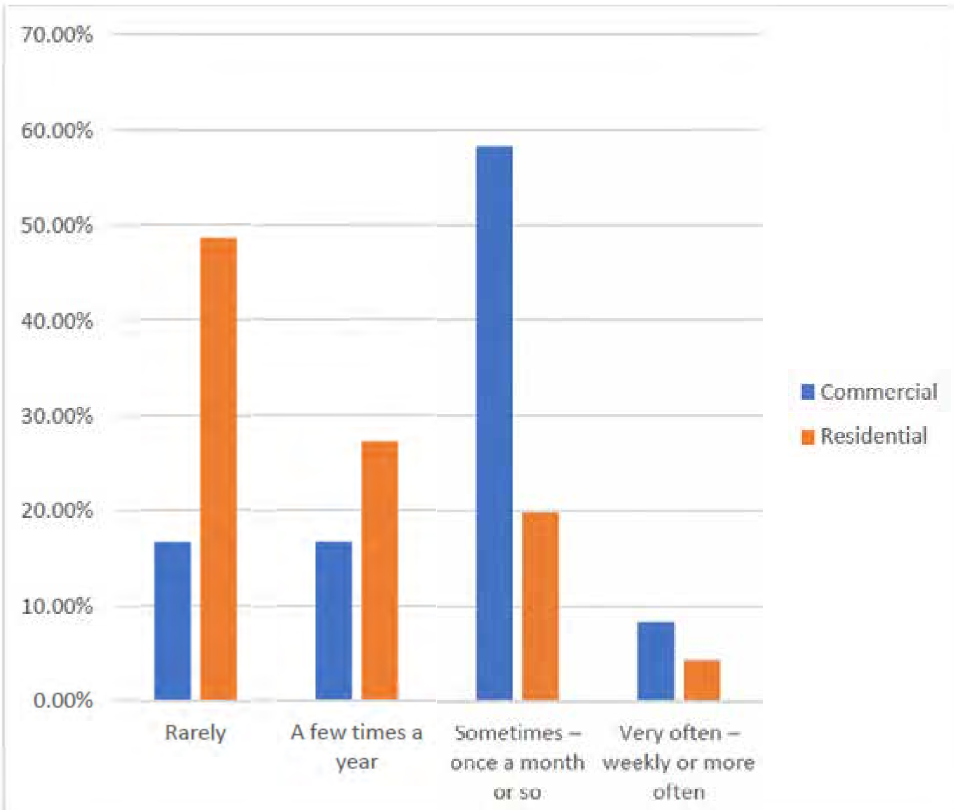


This question, which was answered by 269 respondents, shows that a strong majority of both commercial (58.33%) and residential (59.53%) customers are "Very satisfied" with the electricity service from Northern Ontario Wires. Additionally, 16.67% of commercial customers and 19.84% of residential customers are "Somewhat satisfied." A smaller portion, 8.33% of commercial and 10.12% of residential customers, are neutral, neither satisfied nor dissatisfied. However, 16.67% of commercial customers and 7.00% of residential customers are "Somewhat dissatisfied," and 3.50% of residential customers are "Very dissatisfied," with no commercial customers reporting strong dissatisfaction. These results indicate a generally high level of satisfaction with the service, though there is a small group who are less satisfied.

Power Quality and Reliability

4. How often do you experience problems with your electricity service, such as flickering or brief power outages?

- ☐ Very often – weekly or more often
- ☐ Sometimes – once a month or so
- ☐ A few times a year
- ☐ Rarely

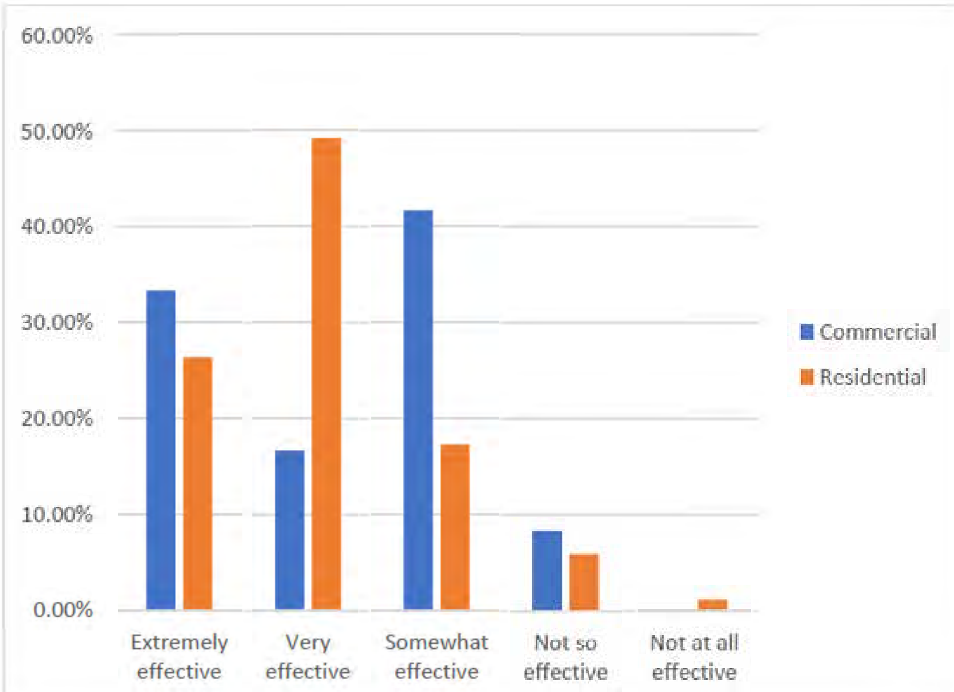


This question, which was answered by 269 respondents, reveals that 48.64% of residential customers and 16.67% of commercial customers rarely experience problems with their electricity service, such as flickering or brief outages. Additionally, 27.24% of residential customers and 16.67% of commercial customers report experiencing these issues a few times a year. A larger portion of commercial customers, 58.33%, experience problems sometimes—about once a month or so—compared to 19.84% of residential customers. Meanwhile, 8.33% of commercial customers and 4.28% of residential customers report experiencing problems very often, on a weekly or more frequent basis.

How would you rate your utility's ability in...

5. Restoring service when a power outage occurs

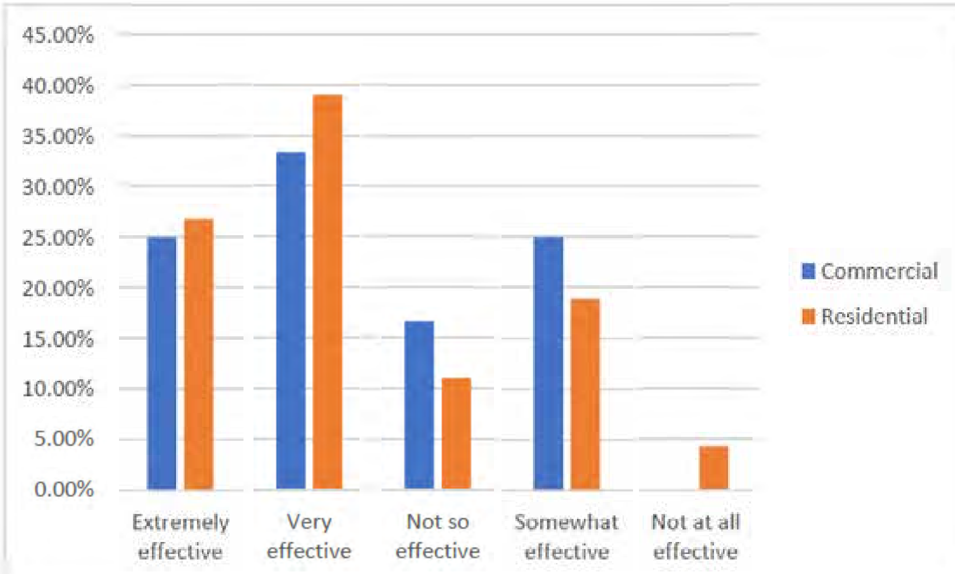
- ☐ Extremely effective
- ☐ Very effective
- ☐ Somewhat effective
- ☐ Not so effective
- ☐ Not at all effective



This question was answered by 266 respondents, showing that 41.67% of commercial customers find service restoration after power outages to be "Somewhat effective," while 17.32% of residential customers share this view. Notably, 49.21% of residential customers rate the service as "Very effective," and 16.67% of commercial customers echo this sentiment. Additionally, 33.33% of commercial customers view the restoration service as "Extremely effective," slightly higher than the 26.38% of residential customers. These results highlight the strong satisfaction among residential customers and demonstrate the effectiveness of service restoration for commercial clients, with opportunities to further enhance the experience for all customer segments.

6. Minimizing the number of power outages

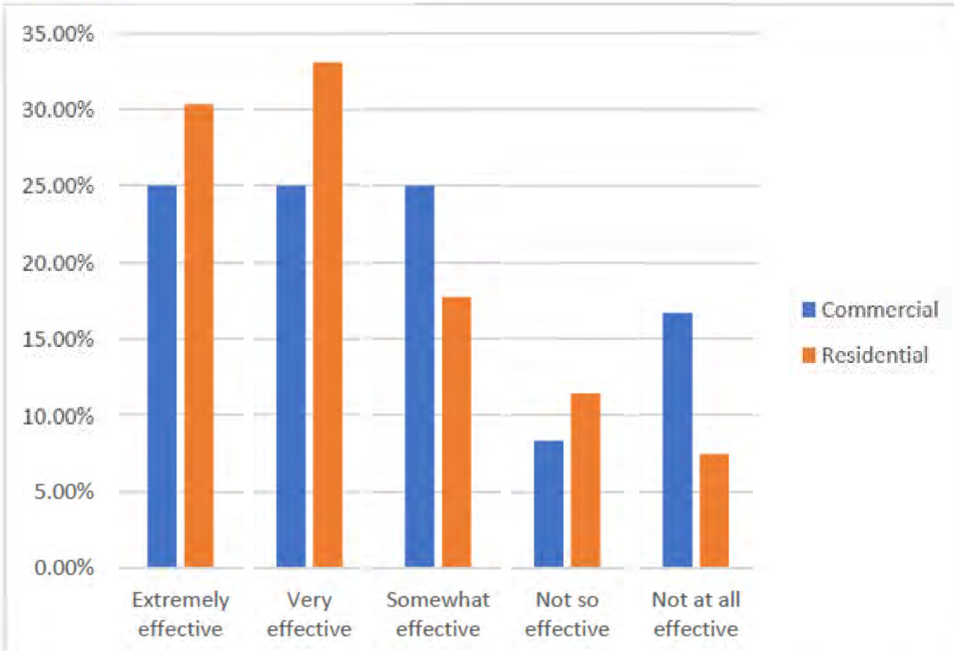
- ☐ Extremely effective
- ☐ Very effective
- ☐ Somewhat effective
- ☐ Not so effective
- ☐ Not at all effective



In response to this question, 266 respondents provided their feedback. Among them, 58.33% of commercial customers and 65.75% of residential customers found the efforts to minimize power outages to be either "Very effective" or "Extremely effective." These results indicate that the majority view the efforts positively, reflecting strong satisfaction across both commercial and residential customers.

7. Providing information about extended outages

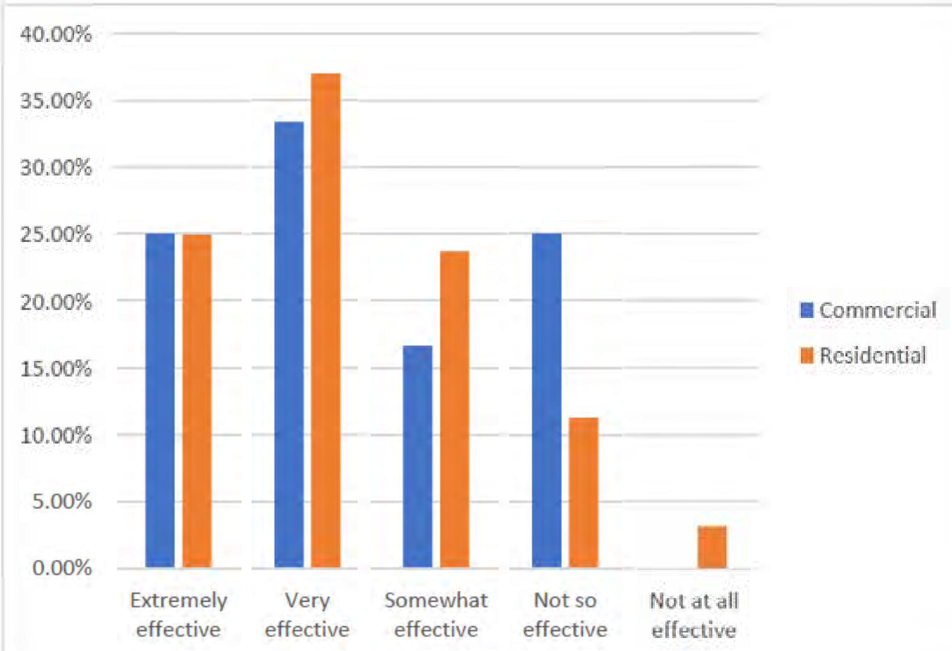
- ☐ Extremely effective
- ☐ Very effective
- ☐ Somewhat effective
- ☐ Not so effective
- ☐ Not at all effective



For this question, which was answered by 266 respondents, 81.10% of residential customers and 75% of commercial customers rated the information provided about extended outages as either "Very effective," "Extremely effective," or "Somewhat effective." This indicates that a strong majority of customers across both segments are satisfied with the communication efforts during extended outages, reflecting the effectiveness of the strategies used to keep them informed.

8. Being reachable by telephone * during an outage

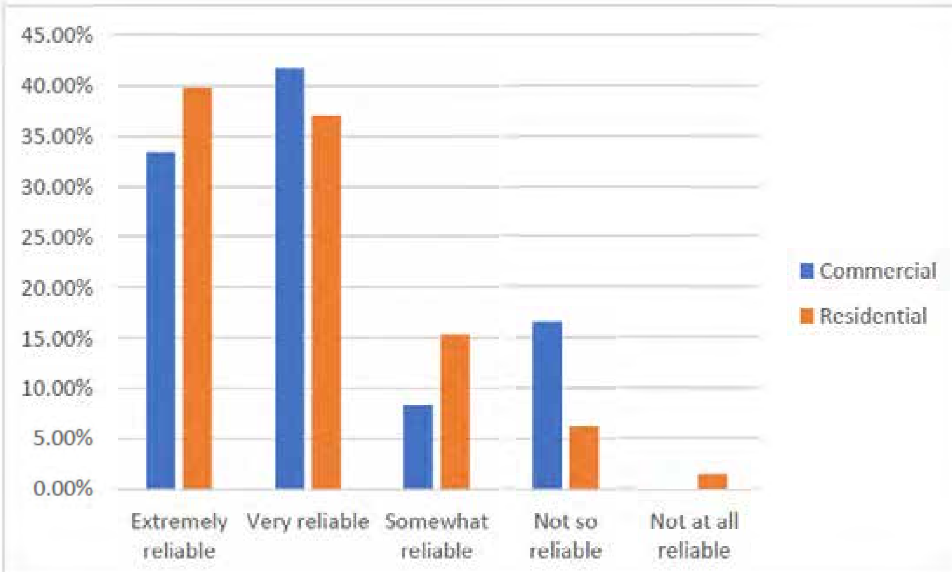
- ☐ Extremely effective
- ☐ Very effective
- ☐ Somewhat effective
- ☐ Not so effective
- ☐ Not at all effective



For this question, which was answered by 266 respondents, 75.00% of commercial customers and 85.54% of residential customers rated being reachable by telephone during an outage as either "Extremely effective," "Very effective," or "Somewhat effective." These results indicate a high level of satisfaction among both customer groups with telephone reachability during outages. The strong positive feedback from the majority of respondents highlights the effectiveness of the current approach in maintaining communication during outages.

9. How would you rate the overall reliability of electricity from your utility?

- ☐ Extremely reliable
- ☐ Very reliable
- ☐ Somewhat reliable
- ☐ Not so reliable
- ☐ Not at all reliable

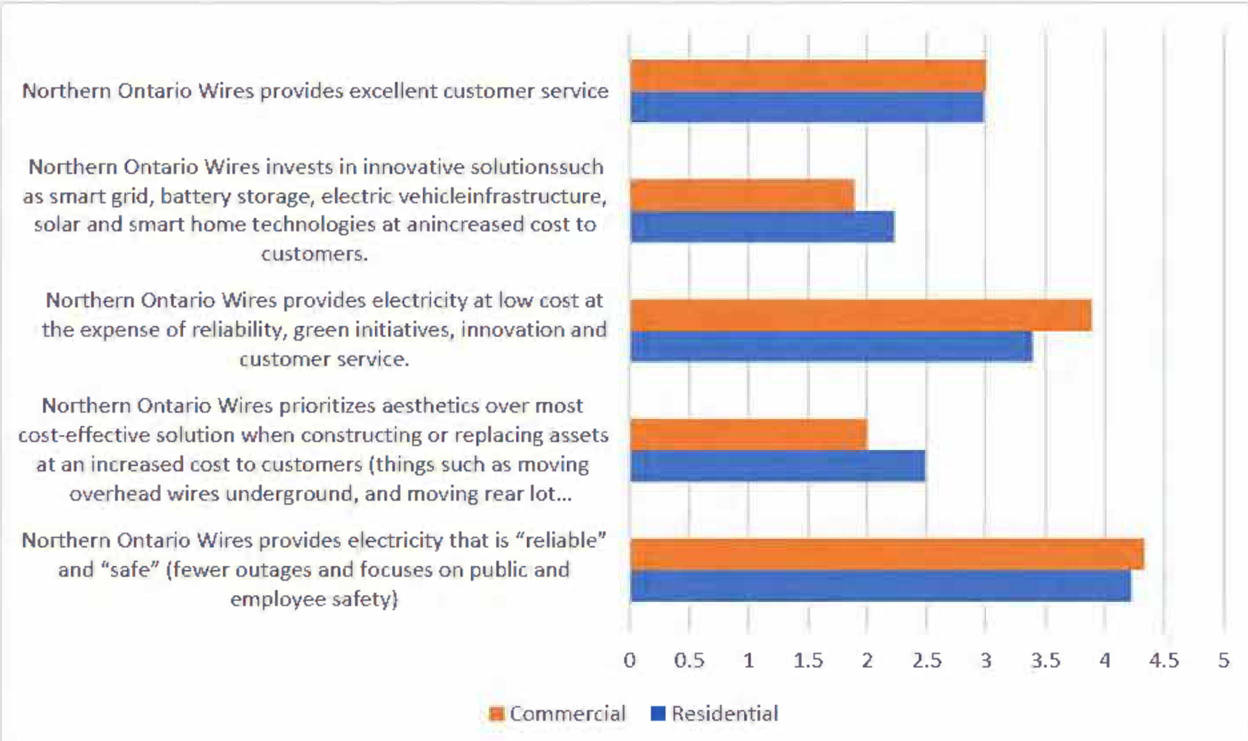


For this question, which was answered by 266 respondents, 83.33% of commercial customers and 92.12% of residential customers rated the overall reliability of electricity from their utility as either "Extremely reliable," "Very reliable," or "Somewhat reliable." These results demonstrate strong confidence in the reliability of electricity provided by the utility, with the majority of both commercial and residential customers expressing satisfaction. This positive feedback highlights the effectiveness of the utility's efforts to ensure consistent and reliable electricity service.

Customer Priorities

Based on these five options, rank each from one to five with one being most important and five being least important to you.

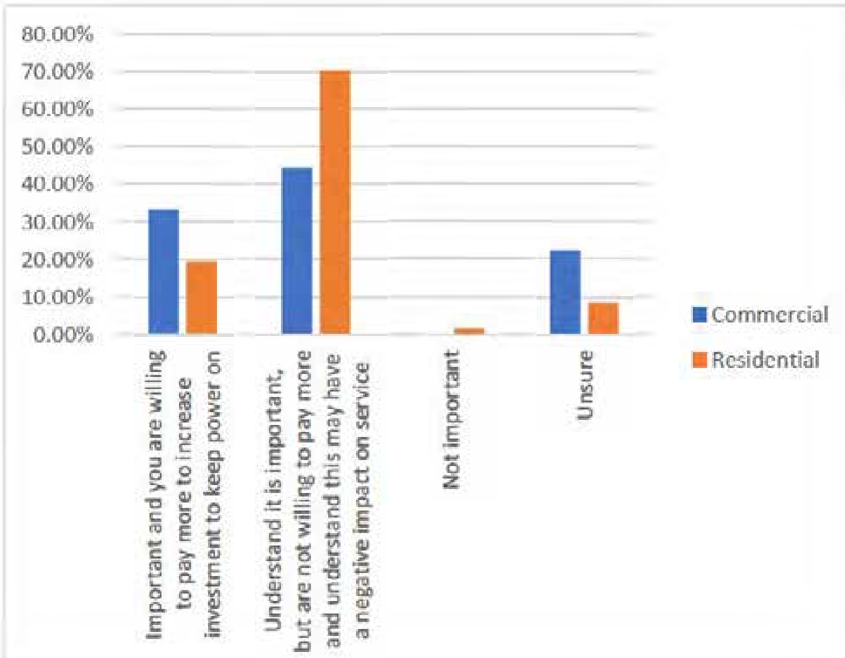
- ☐ Northern Ontario Wires provides electricity that is "reliable" and "safe" (fewer outages and focuses on public and employee safety)
- ☐ Northern Ontario Wires prioritizes aesthetics over most cost-effective solution when constructing or replacing assets at an increased cost to customers (things such as moving overhead wires underground, and moving rear lot infrastructure to front of property)
- ☐ Northern Ontario Wires provides electricity at low cost at the expense of reliability, green initiatives, innovation and customer service.
- ☐ Northern Ontario Wires invests in innovative solutions such as smart grid, battery storage, electric vehicle infrastructure, solar and smart home technologies at an increased cost to customers.
- ☐ Northern Ontario Wires provides excellent customer service



Reliable and safe power emerged as the top priority for both residential and commercial customers, who rated Northern Ontario Wires highly in this area. The positive response to maintaining low electricity costs, even if it compromises reliability, particularly among commercial customers, underscores the need for balanced investment. Although the company received lower ratings for its focus on aesthetics and innovation, these areas represent key opportunities for improvement. By addressing these aspects, Northern Ontario Wires can enhance overall service quality, justifying the need for additional spending to meet evolving customer expectations and ensure continued reliability and safety.

Reliability

10. Northern Ontario Wires strives to always keep the power on. However, there are occasions (ex. due to storms, vehicles accidents and equipment failure) when we experience a power outage. How important is it for you that Northern Ontario Wires continues to minimize power outages?
    a. ☐ Important and you are willing to pay more to increase investment to keep power on
    b. ☐ Understand it is important, but are not willing to pay more and understand this may have a negative impact on service
    c. ☐ Not Important
    d. ☐ Unsure



For this question, which was answered by 245 respondents, 77.77% of commercial customers and 89.83% of residential customers acknowledged the importance of minimizing power outages. Among them, 33.33% of commercial customers and 19.49% of residential customers are even willing to pay more to support increased investment in keeping the power on. These results demonstrate a strong recognition across both customer groups of the importance of efforts to minimize power outages, with many expressing their support for ongoing investment in this area.

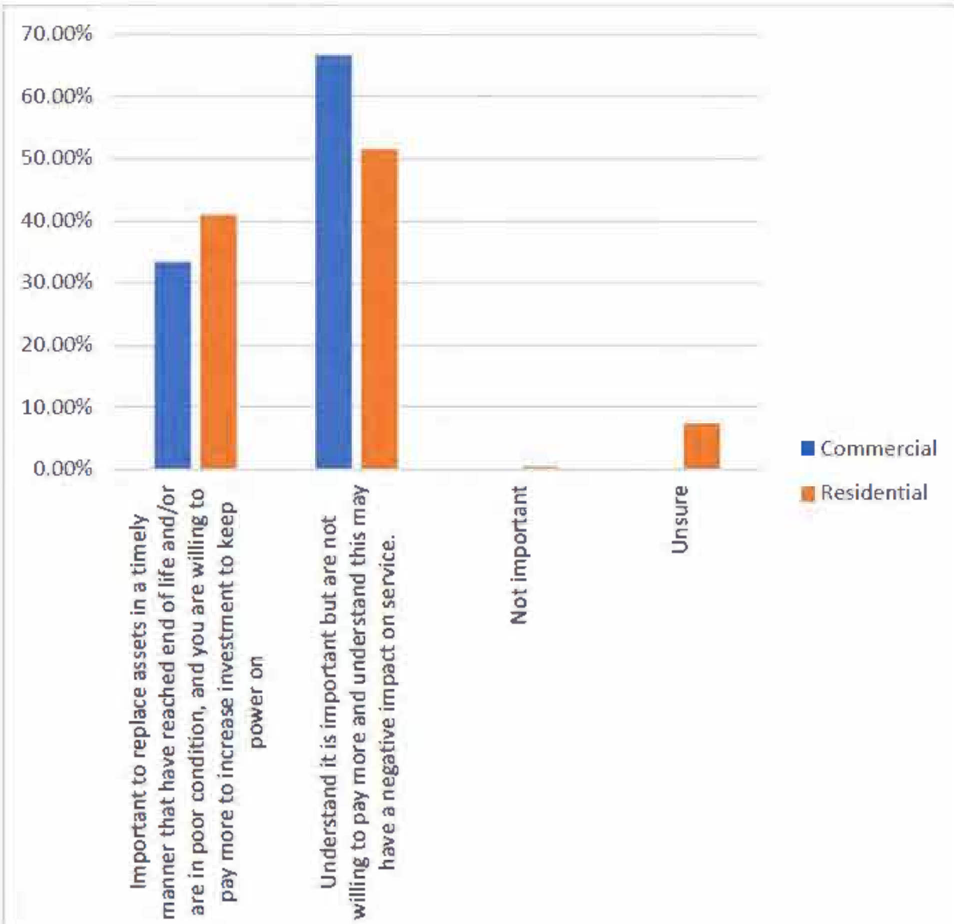
12. Poles, substation, and transformers typically last 40 to 50 years. To ensure an uninterrupted supply of electricity to you, we need to maintain and replace these assets when their useful life has expired and/or are in poor condition. If assets are not replaced on a timely basis, outages could increase, and reliability be negatively impacted. Please select one of the following statements:

a.☐ Important to replace assets in a timely manner that have reached end of life and/or are in poor condition, and you are willing to pay more to increase investment to keep power on

b.☐ Understand it is important but are not willing to pay more and understand this may have a negative impact on service.

c.☐ Not Important

d.☐ Unsure

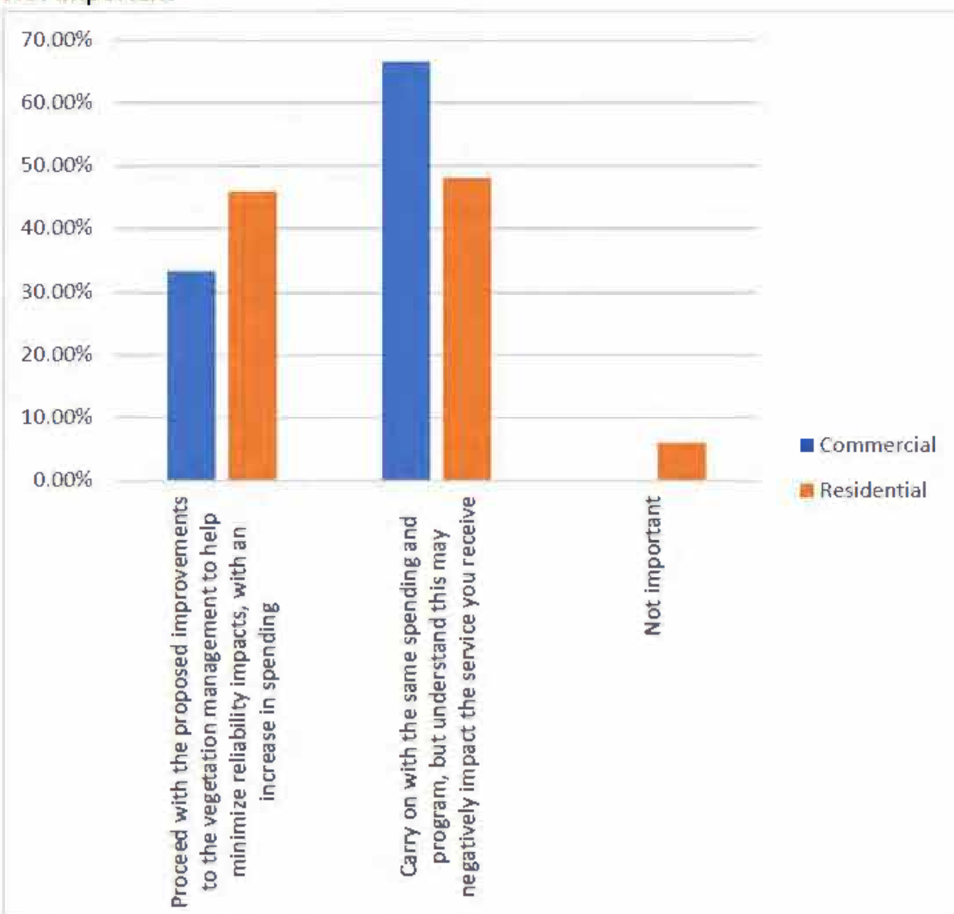


For this question, which was answered by 244 respondents, 100% of commercial customers and 92.34% of residential customers acknowledged the importance of timely replacement of critical assets such as poles, substations, and transformers. Among them, 33.33% of commercial customers and 40.85% of residential customers are even willing to pay more to support increased investment in maintaining these essential assets. These results demonstrate a strong recognition across both customer groups of the importance of proactive asset management, with many expressing their support for ongoing investment to ensure a reliable power supply.

Add in vegetation standards

13. Northern Ontario Wires carriers out vegetation management, which includes tree-trimming, as part of its maintenance practice. This program helps Northern Ontario Wires minimize outages due to tree-contacts. However, we recognize that this service requires improvement to allow for a more standardised and improved approach. Please select one of the following statements:

a. ☐ Proceed with the proposed improvements to the vegetation management to help minimize reliability impacts, with an increase in spending
b. ☐ Carry on with the same spending and program, but understand this may negatively impact the service you receive
c. ☐ Not Important

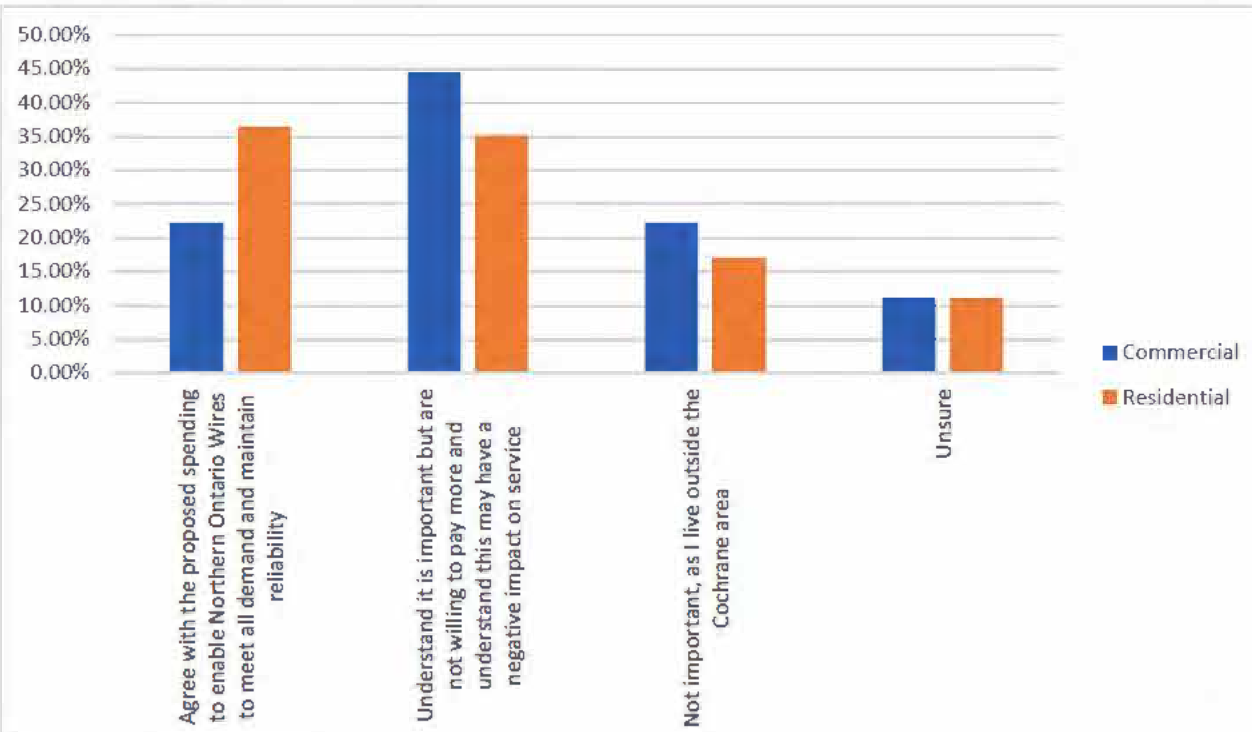


For this question, which was answered by 244 respondents, 100% of commercial customers and 94.04% of residential customers acknowledged the importance of vegetation management to minimize outages due to tree contacts. Among them, 33.33% of commercial customers and 45.96% of residential customers are in favor of proceeding with the proposed improvements to the vegetation management program, even if it requires an increase in spending. These results demonstrate strong support across both customer groups for enhancing vegetation management efforts to ensure continued reliability and minimize outages.

Future Expenditures

14. Northern Ontario Wires has identified that load demand in its Cochrane area is increasing due to notice from two industrial sites on their requirements for additional electrical supply. To accommodate this and continue to meet all customer demand in the area, as well as replace its station assets that are at end of life, Northern Ontario is proposed to build a new Municipal Transformer station. This is estimated to cost an additional $15M over the forecast period on top of its typical spending buckets. Please select one of the following statements:

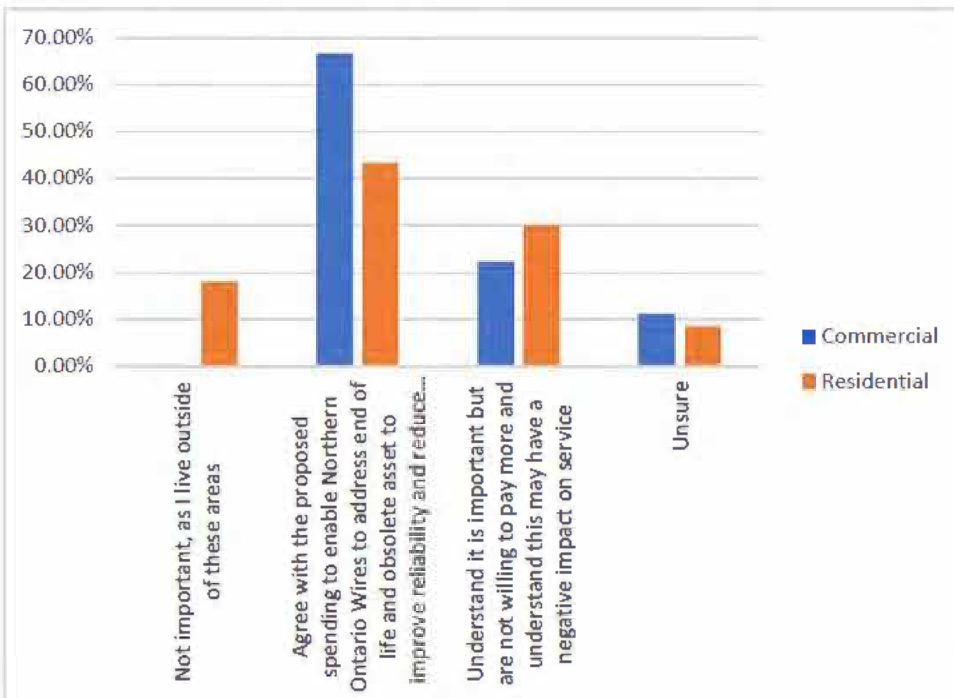
a.☐ Not important, as I live outside the Cochrane area.
b.☐ Agree with the proposed spending to enable Northern Ontario Wires to meet all demand and maintain reliability.
c.☐ Understand it is important but are not willing to pay more and understand this may have a negative impact on service.
d.☐ Unsure.



Overall, respondents strongly support the proposed spending to meet increasing load demand and maintain reliability in the Cochrane area. Among the 107 respondents from Cochrane, 50% of commercial customers and 52.43% of residential customers agree with the investment to build a new Municipal Transformer Station, with additional recognition of its importance among those unwilling to pay more. The rate increase associated with this project would mainly impact commercial customers, as residential customers are protected under the Distribution Rate Protection program, ensuring no additional costs for them. These results underscore a strong consensus on the need to maintain and upgrade infrastructure to support Cochrane's growing energy needs while protecting residential customers from financial impact.

15. To further address its reliability and replace asset that are at end of life and deteriorating, Northern Ontario Wires is continuing its voltage conversion projects in both Kapuskasing and Iroquois Falls service areas. These multi-year projects are aimed to improve reliability and reduce system losses. These projects, outside of the new station, will be Northern Ontario Wires biggest expenditures during the forecast period. Please select one of the following statements:

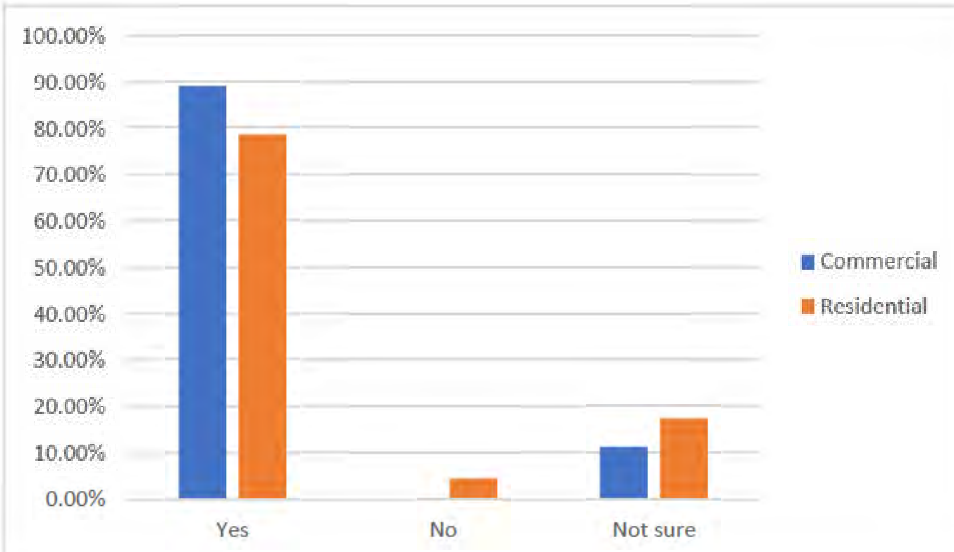
A.☐Not important, as I live outside of these areas.
B.☐Agree with the proposed spending to enable Northern Ontario Wires to address end of life and obsolete asset to improve reliability and reduce system losses.
C.☐Understand it is important but are not willing to pay more and understand this may have a negative impact on service.
D.☐Unsure.



For this question, which was answered by 242 respondents, a significant 73.89% of commercial customers and 73.39% of residential customers recognize the importance of Northern Ontario Wires' proposed spending to address end-of-life and obsolete assets, aiming to improve reliability and reduce system losses. Of these, 66.67% of commercial customers and 43.35% of residential customers are willing to pay more to support these critical investments. These results reflect strong overall support for the ongoing voltage conversion projects in Kapuskasing and Iroquois Falls, underscoring the commitment of both commercial and residential customers to ensuring a reliable and efficient electricity supply.

16. To enable Northern Ontario Wires crews to continue to maintain its system, respond to emergencies and carry out capital investments, there is a need to have a well-maintained fleet of vehicles. Northern Ontario Wires has identified the need to replace two of its large vehicles, that have reached end of life, during the forecast period. Do you agree that Northern Ontario Wires should be prudent and replace vehicles when they have reached end of life?

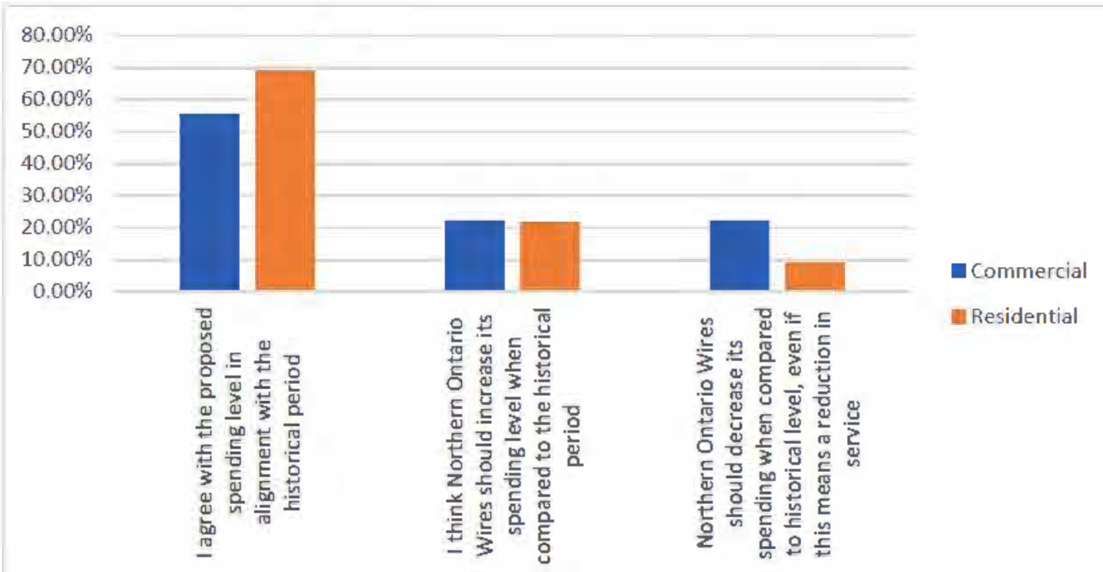
A.☐ Yes
B.☐ No
C.☐ Not Sure



For this question, which was answered by 241 respondents, 88.89% of commercial customers and 78.45% of residential customers agree that Northern Ontario Wires should be prudent and replace vehicles when they have reached the end of their life. Meanwhile, 17.24% of residential customers and 11.11% of commercial customers are "Not sure" about this need. Only 4.31% of residential customers disagreed with the replacement of vehicles, with no commercial customers opposing the idea. These results indicate strong support for the prudent replacement of vehicles, particularly among commercial customers, reflecting a general understanding of the importance of maintaining a reliable fleet for system maintenance and emergency response.

17. Northern Ontario Wires is planning on continuing to invest in its computer hardware and software, buildings and tools and equipment to enable the continued operation of its network. These investments are fundamental to enabling Northern Ontario wires and its staff carry out its jobs in an efficient and safe manner. Northern Ontario Wires is proposing to spend a similar amount in the forecast period when compared to the 2017-2023 period. In relation to these investments, do you agree that Northern Ontario Wires is being prudent in its investments for the forecast period?

A. ☐ I agree with the proposed spending level in alignment with the historical period.
B. ☐ I think Northern Ontario Wires should increase its spending level when compared to the historical period.
C. ☐ Northern Ontario Wires should decrease its spending when compared to historical level, even if this means a reduction in service.

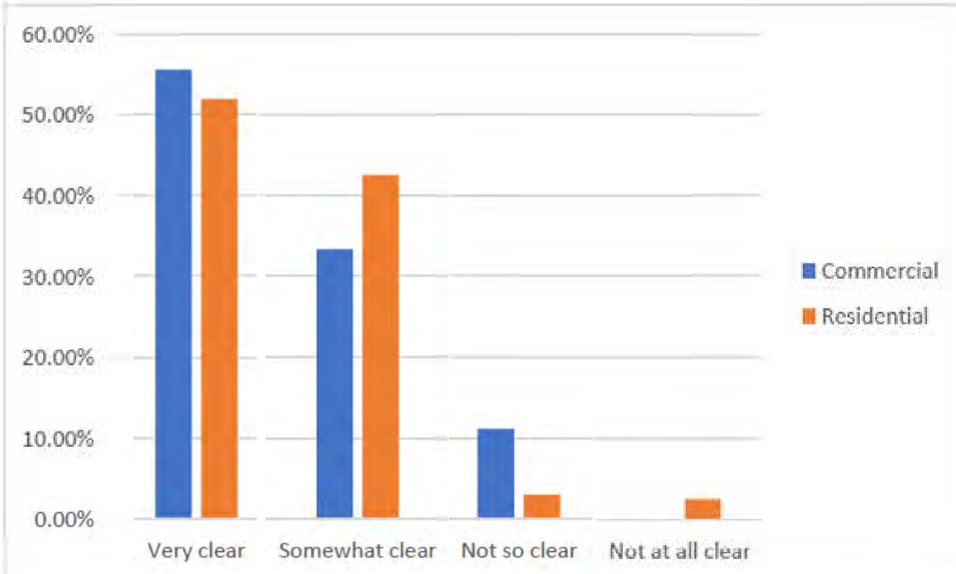


For this question, which was answered by 238 respondents, a strong majority of 77.78% of commercial customers and 90.83% of residential customers agree that Northern Ontario Wires is being prudent in its investments for the forecast period, either supporting the proposed spending level in alignment with the historical period or advocating for an increase in spending. These results indicate broad support for Northern Ontario Wires' approach to maintaining and enhancing its infrastructure, ensuring continued efficient and safe operations.

Billing and Payment

18. Do you find that the explanations of charges on your bill are clear?

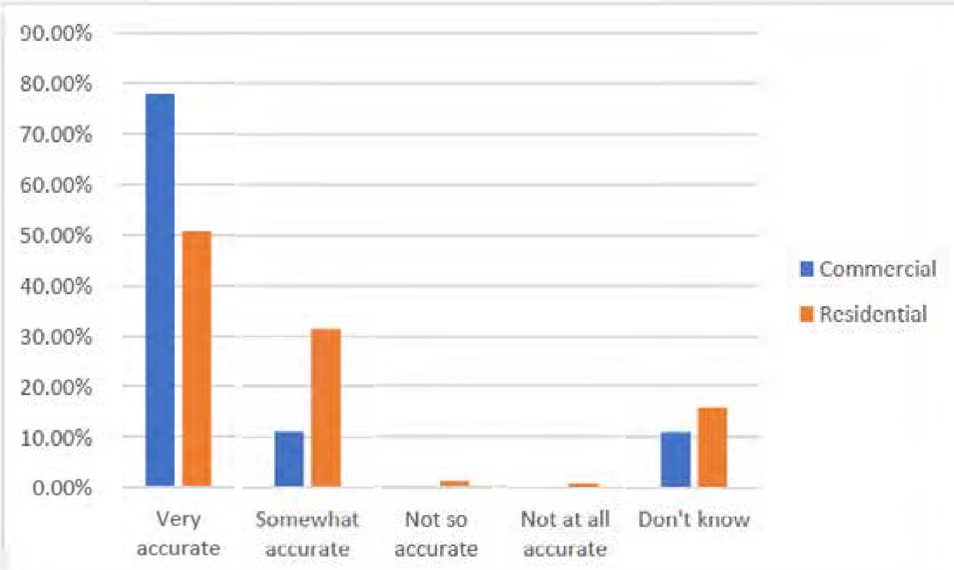
- ☐ Very clear
- ☐ Somewhat clear
- ☐ Not so clear
- ☐ Not at all clear



For this question, which was answered by 242 respondents, a significant majority—88.89% of commercial customers and 94.42% of residential customers—find the explanations of the charges on their bill to be clear, with 55.56% of commercial customers and 51.93% of residential customers describing the explanations as "Very clear." Only a small percentage of respondents, 11.11% of commercial customers and 5.58% of residential customers, find the explanations to be "Not so clear" or "Not at all clear." These results highlight the overall effectiveness of the billing explanations provided by Northern Ontario Wires, with the vast majority of customers perceiving them as clear and understandable.

19. Is your bill accurate?

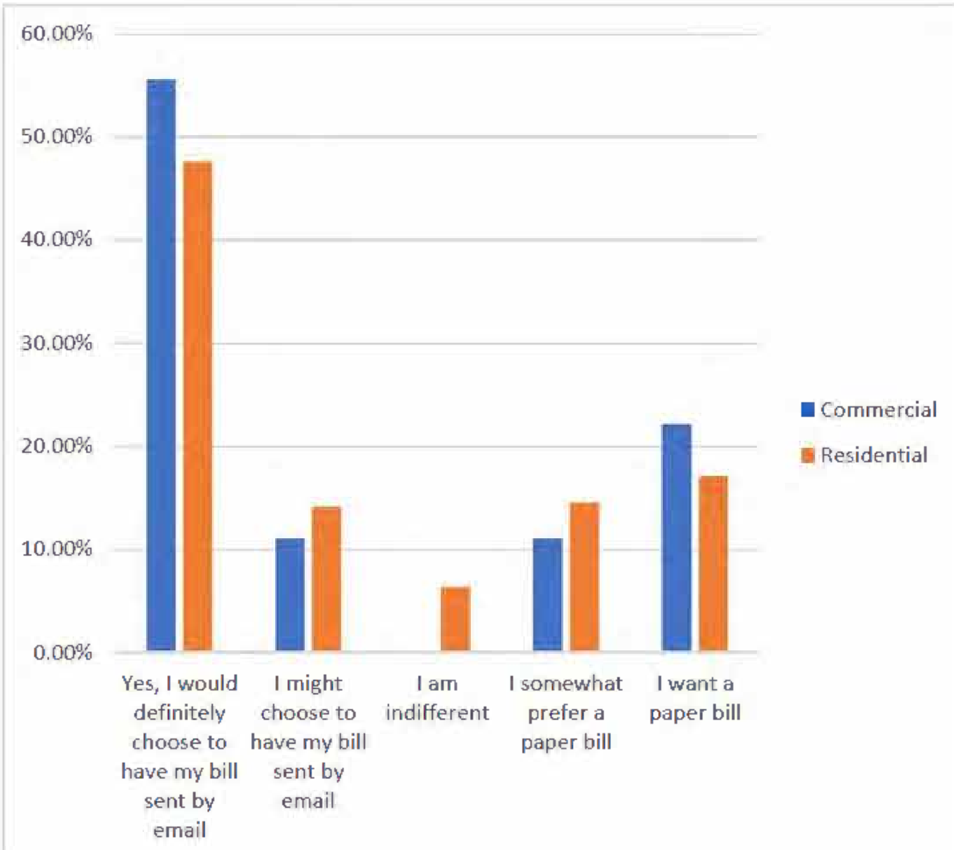
- ☐ Very accurate
- ☐ Somewhat accurate
- ☐ Not so accurate
- ☐ Not at all accurate
- ☐ Don't know



For this question, which was answered by 242 respondents, a strong majority—88.89% of commercial customers and 81.97% of residential customers—believe their bill is accurate, with 77.78% of commercial customers and 50.64% of residential customers describing it as "Very accurate." Only a very small percentage of respondents, 1.29% of residential customers, find their bill to be "Not so accurate" or "Not at all accurate." These results indicate that the majority of customers perceive their billing as accurate, reflecting confidence in the billing system provided by Northern Ontario Wires.

20. If you could have your electricity bill sent by e-mail rather than as a paper bill, would you choose that option?

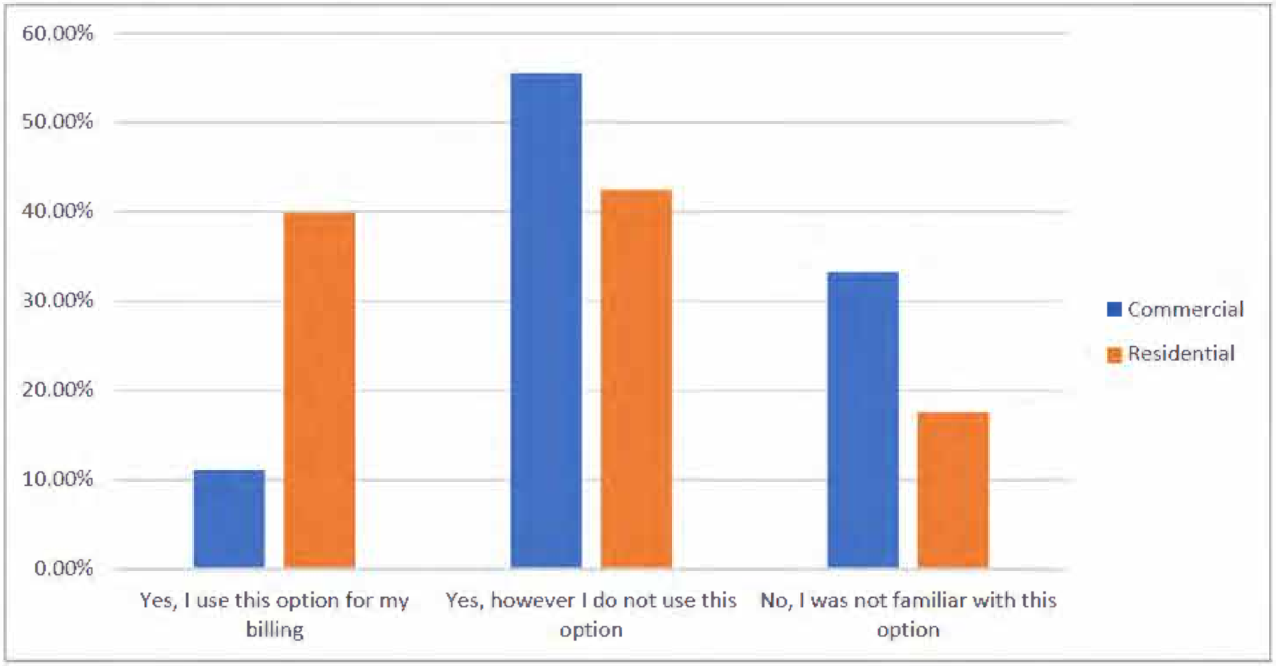
- ☐ Yes, I would definitely choose to have my bill sent by email
- ☐ I might choose to have my bill sent by email
- ☐ I am indifferent
- ☐ I somewhat prefer a paper bill
- ☐ I want a paper bill



For this question, which was answered by 242 respondents, a significant majority—66.67% of commercial customers and 61.80% of residential customers—are open to the idea of receiving their electricity bill by email, with many either definitely choosing the option or being open to it. Specifically, 55.56% of commercial customers and 47.64% of residential customers would definitely opt for email billing, while an additional 11.11% of commercial customers and 14.16% of residential customers might consider it. On the other hand, 33.33% of commercial customers and 38.20% of residential customers still prefer receiving a paper bill, whether strongly or somewhat. These results highlight a growing trend towards digital billing, with a clear majority of customers showing interest in moving away from traditional paper bills.

21. Are you familiar with Northern Ontario Wires e-bill option? (Information regarding setting up this option can be found under the 'Paperless' tab on our website)

- ☐ Yes, I use this option for my billing.
- ☐ Yes, however I do not use this option.
- ☐ No, I was not familiar with this option.



For this question, which was answered by 242 respondents, a strong majority—66.67% of commercial customers and 82.40% of residential customers—are familiar with Northern Ontario Wires' e-bill option. Among them, 11.11% of commercial customers and 39.91% of residential customers already use this option for their billing. An additional 55.56% of commercial customers and 42.49% of residential customers are aware of the e-bill option but have not yet adopted it. Only a small portion, 33.33% of commercial customers and 17.60% of residential customers, were not familiar with the e-bill option. These results suggest that most customers are aware of and open to the e-bill option, with a substantial number already utilizing this convenient service.

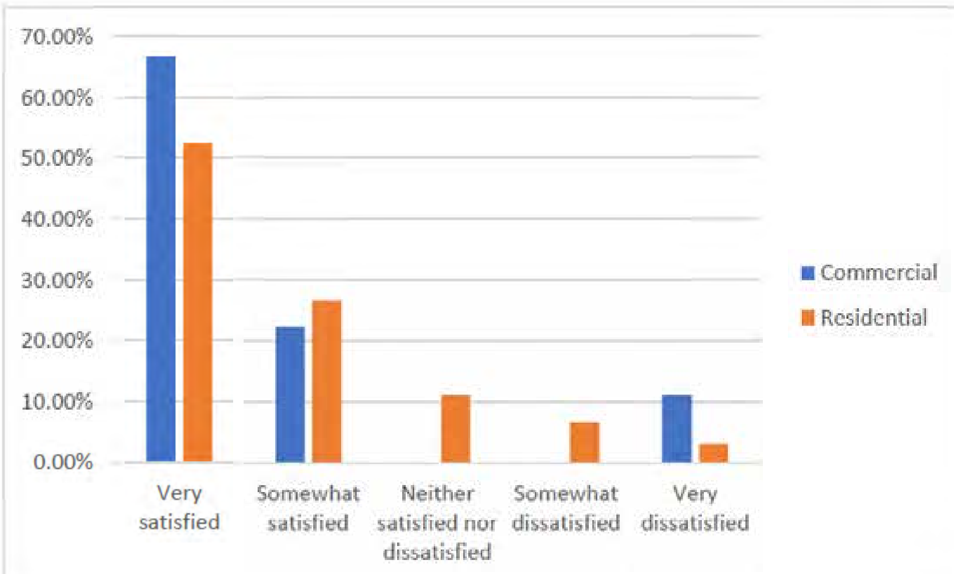
22. As we try to develop our procedures, how might you recommend we improve the incentive for customers to transition to e-billing?

The responses to the question on how to improve incentives for customers to transition to e-billing largely suggest offering monetary incentives, such as discounts, bill credits, or contests, as the most effective strategies. Many respondents proposed discounts on bills or small rebates as encouragement. Some also suggested implementing fees for paper billing as a way to push customers towards e-billing. Other ideas included making the e-billing system more user-friendly, offering trial periods, and providing better communication or assistance for those less comfortable with technology. There were also concerns raised about respecting the needs of those who prefer paper bills, particularly seniors and those without internet access. Overall, the feedback highlights a mix of incentives and support measures to encourage the transition to e-billing while being mindful of customer preferences and capabilities.

Communications

23. How satisfied are you with Northern Ontario Wires in getting you the information you need?

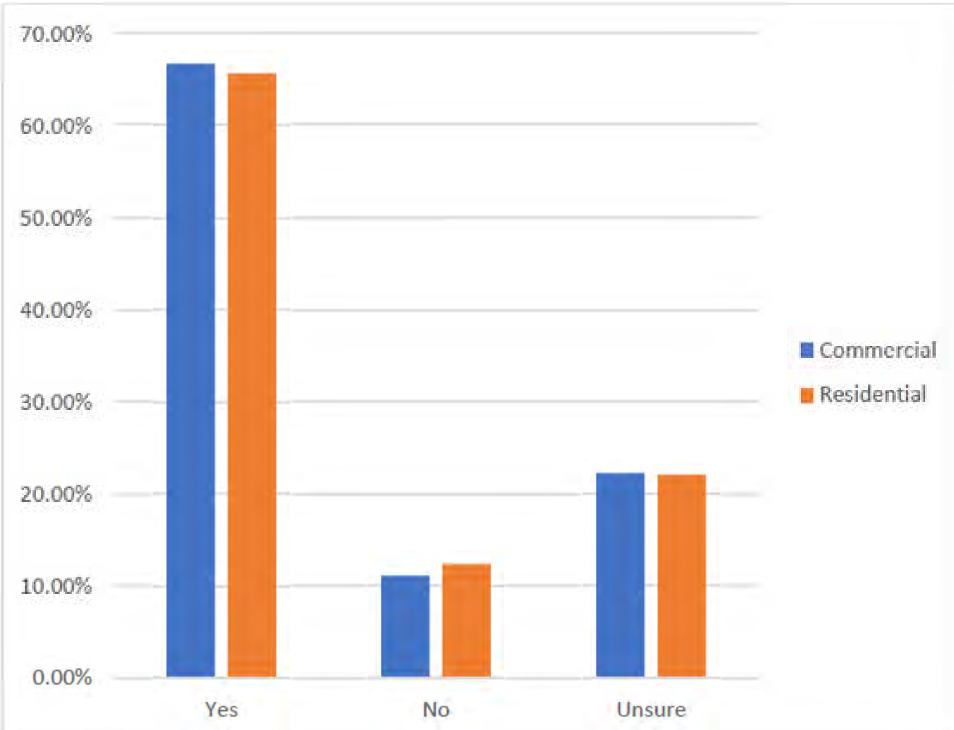
- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied



For this question, which was answered by 234 respondents, a strong majority—88.89% of commercial customers and 79.11% of residential customers—are satisfied with the information they receive from Northern Ontario Wires. Specifically, 66.67% of commercial customers and 52.44% of residential customers are "Very satisfied," with an additional 22.22% of commercial customers and 26.67% of residential customers being "Somewhat satisfied." Only a small percentage of respondents, 11.11% of commercial customers and 9.78% of residential customers, expressed dissatisfaction. These results highlight a high level of satisfaction among customers, reflecting positively on Northern Ontario Wires' efforts to provide the necessary information effectively.

24. Does Northern Ontario Wires provide you with useful information, tools, tips and assistance to help you manage your electricity consumption and bills?

- ☐ Yes
- ☐ No
- ☐ Unsure



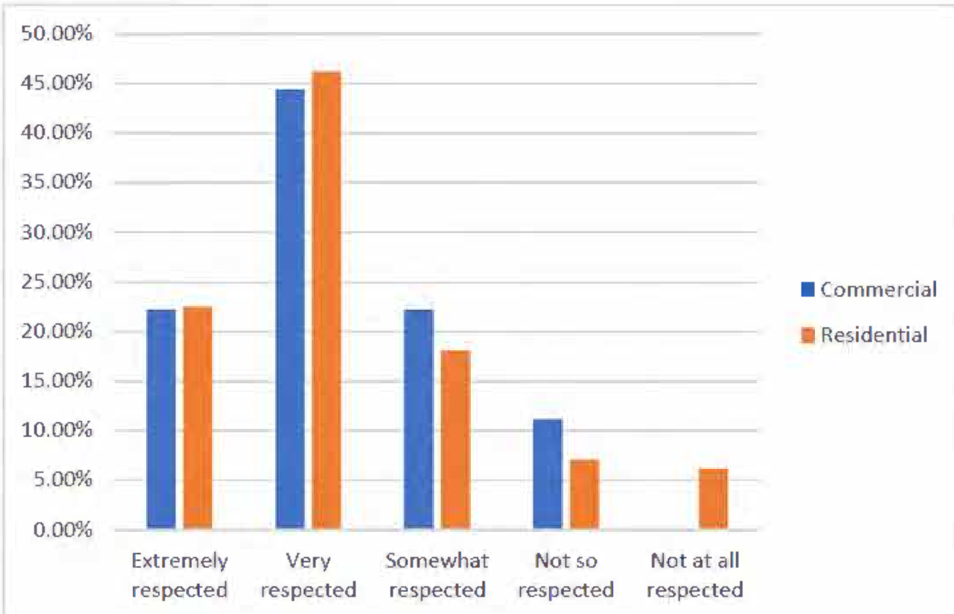
For this question, which was answered by 236 respondents, a solid majority—66.67% of commercial customers and 65.64% of residential customers—affirm that Northern Ontario Wires provides useful information, tools, tips, and assistance to help them manage their electricity consumption and bills. Only a small portion of respondents, 11.11% of commercial customers and 12.33% of residential customers, do not feel they receive this support. Additionally, 22.22% of commercial customers and 22.03% of residential customers are unsure. These results indicate that most customers appreciate the resources provided by Northern Ontario Wires, which are effectively helping them manage their electricity usage and expenses.

25. How could Northern Ontario Wires improve its way of providing you with the information you need?

The responses suggest that many customers appreciate the current efforts by Northern Ontario Wires in providing information, particularly through email and social media updates. However, there are several suggestions for improvement, including better communication during power outages, the introduction of an app or online outage maps, and more frequent updates through various channels like newsletters, email, and social media. Some customers also recommend improving the website, offering real-time updates, and sending more information about energy-saving tips and billing options. Overall, while many are satisfied, there is a clear desire for more proactive and accessible communication, especially during outages.

26. Would you say that your utility is a respected company in the community?

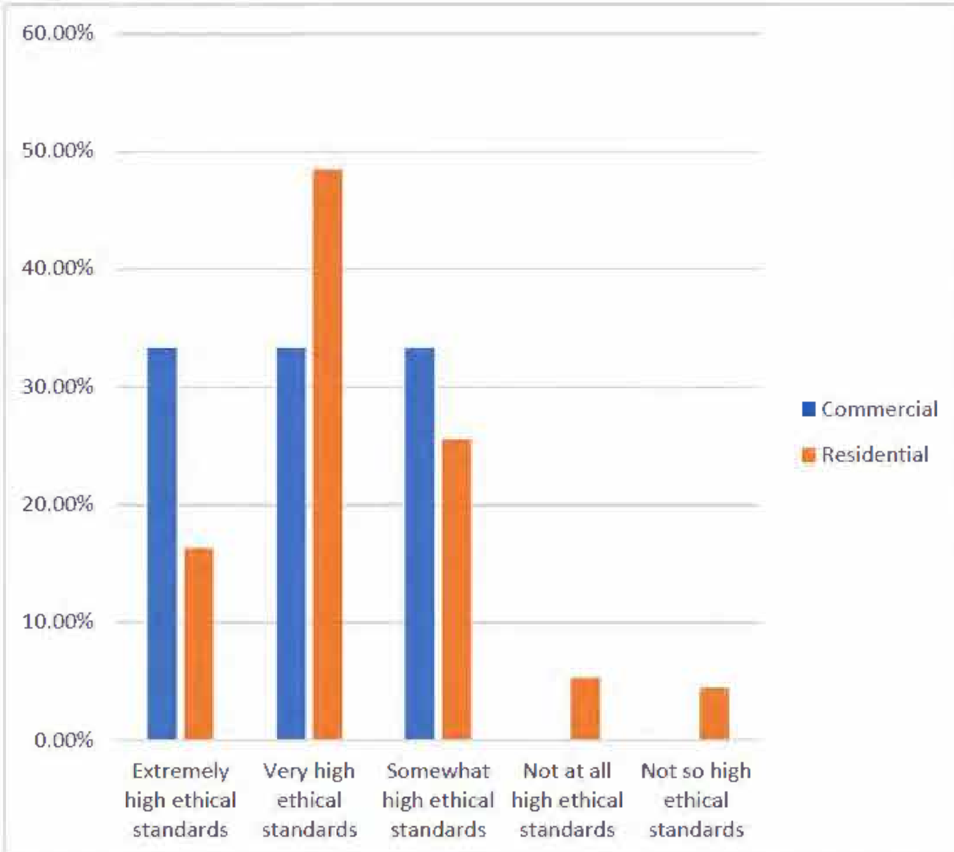
- ☐ Extremely respected
- ☐ Very respected
- ☐ Somewhat respected
- ☐ Not so respected
- ☐ Not at all respected



For this question, which was answered by 236 respondents, a large majority—88.88% of commercial customers and 86.79% of residential customers—consider Northern Ontario Wires to be a respected company in the community. Specifically, 66.66% of commercial customers and 68.73% of residential customers believe the utility is either "Extremely respected" or "Very respected." Only a small percentage of respondents, 11.11% of commercial customers and 13.22% of residential customers, feel the utility is "Not so respected" or "Not at all respected." These results indicate that Northern Ontario Wires enjoys a strong reputation within the community, with the vast majority of customers viewing the company positively.

27. Would you say that your utility has a high standard of business ethics?

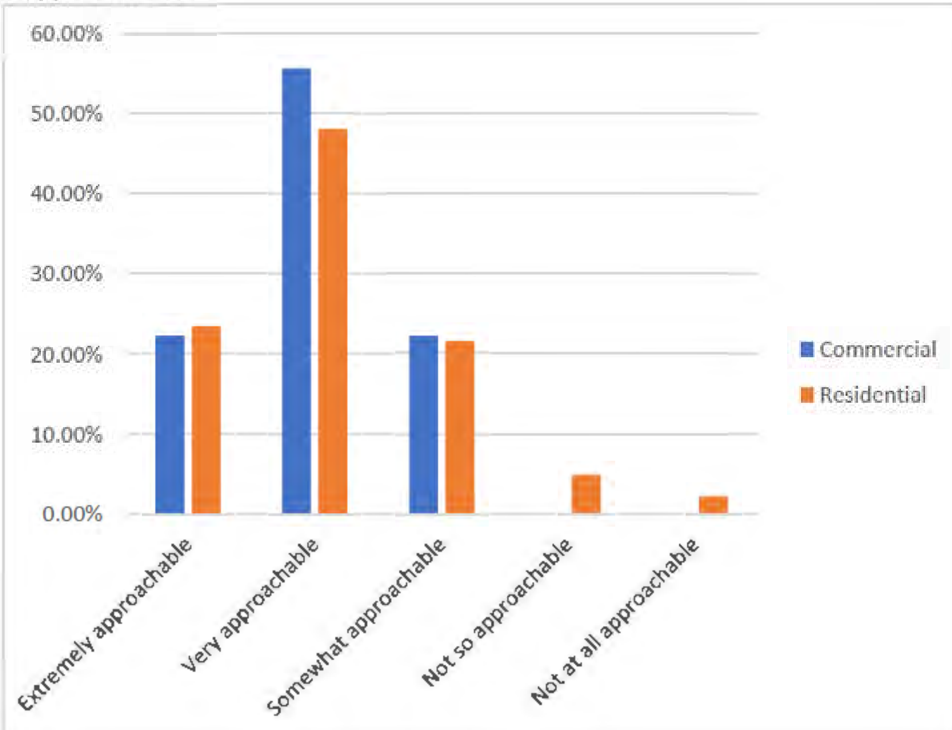
- ☐ Extremely high ethical standards
- ☐ Very high ethical standards
- ☐ Somewhat high ethical standards
- ☐ Not so high ethical standards
- ☐ Not at all high ethical standards



For this question, which was answered by 236 respondents, a strong majority—100% of commercial customers and 90.31% of residential customers—believe that Northern Ontario Wires operates with high ethical standards. Specifically, 66.66% of commercial customers and 64.76% of residential customers rate the utility as having either "Extremely high" or "Very high" ethical standards. Additionally, 33.33% of commercial customers and 25.55% of residential customers consider the utility to have "Somewhat high" ethical standards. Only a small percentage of residential customers, 9.70%, feel that the utility does not maintain high ethical standards. These results indicate that Northern Ontario Wires is widely regarded as an ethical company by the vast majority of its customers.

28. Would you describe your utility as approachable?

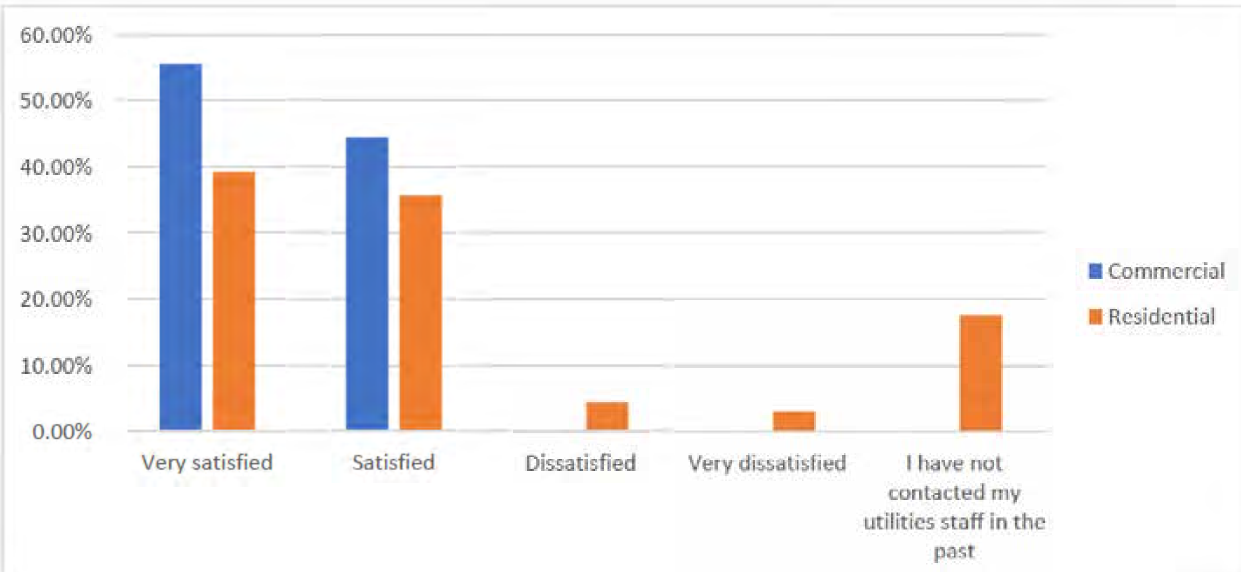
- ☐ Extremely approachable
- ☐ Very approachable
- ☐ Somewhat approachable
- ☐ Not so approachable
- ☐ Not at all approachable



For this question, which was answered by 236 respondents, a significant majority—100% of commercial customers and 92.96% of residential customers—describe Northern Ontario Wires as approachable. Specifically, 77.78% of commercial customers and 71.37% of residential customers rate the utility as either "Extremely approachable" or "Very approachable," while 22.22% of commercial customers and 21.59% of residential customers consider it "Somewhat approachable." Only a small portion of residential customers, 7.05%, feel that the utility is "Not so approachable" or "Not at all approachable." These results demonstrate that Northern Ontario Wires is perceived as a highly approachable company by the vast majority of its customers.

29. Thinking about your most recent contact with the staff of your utility, how satisfied are you with your experience regarding their service?

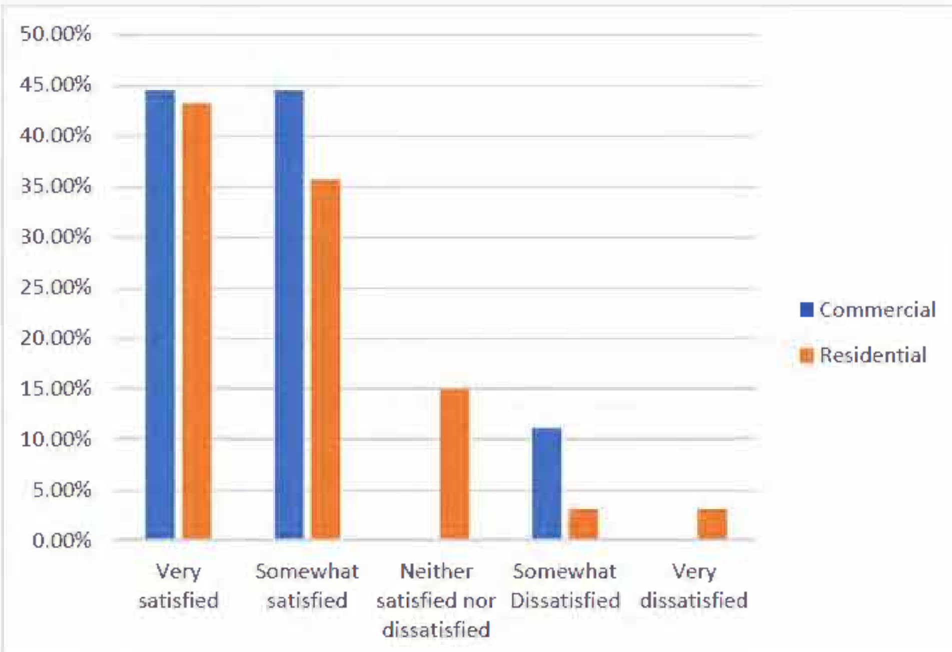
- ☐ Very satisfied
- ☐ Satisfied
- ☐ Dissatisfied
- ☐ Very dissatisfied
- ☐ I have not contacted my utilities staff in the past



For this question, which was answered by 236 respondents, a strong majority—100% of commercial customers and 74.89% of residential customers—are satisfied with their most recent contact with the staff of Northern Ontario Wires. Only a small percentage of residential customers, 7.49%, expressed dissatisfaction, either as "Dissatisfied" or "Very dissatisfied." Additionally, 17.62% of residential customers indicated that they had not contacted utility staff in the past. These results highlight a high level of customer satisfaction with the service provided by Northern Ontario Wires' staff, particularly among those who have had recent interactions.

30. After having taken this survey, how satisfied are you that Northern Ontario Wires has the right plan to address the needs of the communities it serves:

- ☐ Very satisfied
- ☐ Somewhat satisfied
- ☐ Neither satisfied nor dissatisfied
- ☐ Somewhat dissatisfied
- ☐ Very dissatisfied



For this question, which was answered by 236 respondents, a strong majority—88.88% of commercial customers and 78.85% of residential customers—are satisfied that Northern Ontario Wires has the right plan to address the needs of the communities it serves. Specifically, 44.44% of commercial customers and 43.17% of residential customers reported being "Very satisfied," while another 44.44% of commercial customers and 35.68% of residential customers are "Somewhat satisfied." Only a small percentage of respondents, 11.11% of commercial customers and 6.16% of residential customers, expressed dissatisfaction. Additionally, 14.98% of residential customers reported feeling neutral, being neither satisfied nor dissatisfied. These results indicate that the majority of customers feel confident in Northern Ontario Wires' plans to meet community needs.

Appendix C

North & East of Sudbury – Regional Infrastructure Plan

REGIONAL INFRASTRUCTURE PLAN REPORT

[North and East of Sudbury]

Regional Infrastructure Plan Report

North and East of Sudbury

[Date: November 03, 2023]

Lead Transmitter:

Hydro One Networks Inc.

Prepared by:

North & East of Sudbury Technical working group

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Disclaimer

This Regional Infrastructure Plan (RIP) Report was prepared for the purpose of developing an electricity infrastructure plan to address electrical supply needs identified in previous planning phases and also any additional needs identified based on new and/or updated information provided by the RIP Technical Working Group (TWG).

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 Technical Working Group.

The TWG 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 Regional Infrastructure Plan Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Regional Infrastructure Plan 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	**North and East of Sudbury** Region (the "Region")
LEAD	Hydro One Networks Inc. ("HONI")

START DATE: May 10,2023 **END DATE:** November 03, 2023

1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process for the North & East of Sudbury Region, preceded by, the publication of Needs Assessment (NA) report in May 2021 by Hydro One, followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) in August 2021 and in April 2023 published by the IESO respectively.

Hydro One as the lead transmitter undertake the development of a RIP with input from the TWG for the region and publishes a RIP report. The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs. This is second cycle of RIP.

2. OBJECTIVES AND SCOPE

Objectives:

- Provide a comprehensive summary of needs and wires plans to address the needs for the North & East of Sudbury Region.
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- 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.

Scope:

- A consolidated report of the needs and relevant wires plans to address near and medium-term needs [2023-2033] identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2023-2043 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the North & East of Sudbury IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

This section provides a detailed overview of the various steps followed during different phases of Regional Planning Process and their outcomes starting with the Needs Assessment, Scoping Assessment, Local Plan, Integrated Regional Resource Plan and finally details the Regional Infrastructure Plan Methodology.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

This section provides a general overview of the Geographical boundaries, Circuit connections and Stations located in the North & East of Sudbury Region though a regional planning area map and a Single Line diagram.

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Hanmer TS to Pinard TS.

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR UNDERWAY

This section provides a summary and brief description of all the projects completed or are currently underway in past ten years.

I. Following Major projects were completed during the last ten years:

- Kapuskasing Area Reinforcement – H9K Circuit Upgrade (2020)
- Kirkland Lake TS (T12/T13) transformers (2017)
- Dymond TS (T3/T4) transformers (2016)
- Timmins TS (T63/T64) with single 83MVA (2016)
- Hanmer TS Northern Station Replacement Project (2022)

II. Following Major projects are underway:

- Kapuskasing Area Reinforcement – Install 115kV Reactive Devices (2023)
- Kirkland Lake TS – Replace low voltage breakers, Instrument Transformers, P&C equipment (2025)
- Hearst TS - Replace low voltage breakers, P&C Equipment, switches (2028)
- Hunta SS - Replace P&C Equipment (2025)
- Porcupine TS – Replace 1 - 500kV/230kV autotransformer (T7), 2- 500kV/115kV autotransformers (T3/T4), switches, station service and P&C equipment (2025)

- Otto Holden TS - Replace 2 – 230 kV/115 kV autotransformers (T3/T4), high voltage breakers, switches, station service equipment, and protections (2027)
- K4 circuit - Refurbish Kirkland Lake TS X Matachewan JCT (10km) (2024)
- A8K/A9K circuits – Refurbish A8K/A9K (90km) (2023)

Note: The planned in-service year for the above projects is tentative and is subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

During the study period, the load in the North & East of Sudbury Region is expected to grow at an average annual rate of approximately 0.50% in winter and 0.25% in summer from 2023 to 2043.

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2043.
- LDCs reconfirmed load forecasts up to 2040. The additional 3 years of forecasts were extrapolated based on the growth rate as a reasonable position to complete the 20-year period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is winter peaking, so this assessment is 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 and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the summer 10-day Limited Time Rating (LTR).
- Regional transmission line and auto transformer capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Resources assumptions align with the IRRP.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the North & East of Sudbury Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway are completed.

I. Needs identified in the region

a. Asset Renewal for Major HV Transmission Equipment

- Kirkland Lake TS
- Hunta SS
- Porcupine TS
- Otto Holden TS
- Hearst TS
- Timmins TS
- Kapuskasing TS
- Dymond TS
- Ansonville TS
- Crystal Falls TS
- Trout Lake TS
- A8K/A9K circuits
- K4 circuit
- T61S circuit
- K1/K2 circuits
- D2H/D3H circuits
- A4H/A5H circuits

b. Station Capacity

- Ramore TS

c. Transmission Line Capacity

- D3K

d. System Reliability, Operation and Load restoration

- Dymond TS - Voltage violation
- Kirkland Lake TS - Voltage control
- Ansonville, Hunta, Kapuskasing TS - Voltage control
- ORTAC load security criteria not met for 500 kV circuit outages
- Difficulty supplying loads during planned outages to circuit D501P

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the North & East of Sudbury Region. The needs include those previously identified in the NA and IRRP for the North & East of Sudbury Region as well as any new needs identified during the RIP phase.

9. CONCLUSION AND RECOMMENDATIONS

The major infrastructure investments recommended by the TWG in the North & East of Sudbury Region is given below:

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers.	Hydro One Transmission	2025	36
Hunta SS	Replacement of P&C and telecom equipment.	Hydro One Transmission	2025	12
Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment.	Hydro One Transmission	2026	91
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment.	Hydro One Transmission	2027	74
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment.	Hydro One Transmission	2028	19
Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections.	Hydro One Transmission	2028	14

Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections.	Hydro One Transmission	2030	24
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment.	Hydro One Transmission	2031	42
Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment.	Hydro One Transmission	2031	11
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment.	Hydro One Transmission	2031	32
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters.	Hydro One Transmission	2033	17
K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km)	Hydro One Transmission	2024	4
T61S	Replace conductor and refurbish circuit Timmins TS x Shiningtree JCT (115km)	Hydro One Transmission	2024	
K1/K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km)	Hydro One Transmission	2024	4
D2H/D3H*	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km)	Hydro One Transmission	2029	96
A4H/A5H**	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km)	Hydro One Transmission	2027	22
Station Capacity Needs				
Ramore TS	To be monitored and reviewed in next planning cycle	Hydro One Distribution	NA	NA
Transmission Line Capacity Needs				
D3K	Monitoring & further exploration in future RIP cycle	Hydro One Transmission	NA	NA

System Reliability, Operation and Load restoration Needs				
Dymond TS	Continue to investigate sizing of the existing 115kV SC11 & SC12 capacitor banks	Hydro One Transmission	NA	NA

Note:

a) The planned in-service dates are tentative and subject to change
b) Costs are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required)

* IESO to inform by end of Q2 2025 if an upgrade is required

** IESO to inform by end of 2024 if an upgrade is required

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1. INTRODUCTION

The Regional Infrastructure Plan (RIP) is the final step of Regional Planning Process where, Hydro One as the lead transmitter undertakes the development of a RIP with input from the TWG for the region and publishes a RIP report. The second cycle of the Regional Planning process for the North & East of Sudbury Region was initiated with the publication of Needs Assessment (NA) report in May 2021 by Hydro One, followed by the Scoping Assessment (SA) & Integrated Regional Resource Plan (IRRP) in August 2021 and in April 2023 published by the IESO respectively.

The RIP report includes a common discussion of all the options and recommended plans and preferred wire infrastructure investments identified in earlier phases to address the near- and medium-term needs.

This report was prepared by the North & East of Sudbury Technical Working Group("TWG"), led by Hydro One Networks Inc. The report presents the results of the assessment based on information provided by the Hydro One, the Local Distribution Companies ("LDC"), the Municipalities and the Independent Electricity System Operator ("IESO"). Participants of the TWG are listed below in Table 1.

Table 1: North & East of Sudbury Region TWG Participants

Hydro One Networks Inc. (Lead Transmitter)	Lead Transmitter
Independent Electricity System Operator ("IESO")	System Operator
Hydro One Networks Inc. (Distribution)	LDC
North Bay Hydro	LDC
Northern Ontario Wires Inc.	LDC
Hearst Power Distribution Co.	LDC
Greater Sudbury Hydro Inc.	LDC

2. OBJECTIVES AND SCOPE OF REGIONAL INFRASTRUCTURE PLAN

This RIP report examines the needs in the North & East of Sudbury Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs for the North & East of Sudbury region.
- Identify new supply needs that may have emerged since previous planning phases (e.g., Needs Assessment, Scoping Assessment, Local Plan, and/or Integrated Regional Resource Plan).
- Assess and develop wires plans to address these new needs.
- 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, asset renewal for major high voltage transmission equipment, transmission, and distribution system capability along with any updates with respect 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 needs and relevant wires plans to address near and medium-term needs (2023-2033) identified in previous planning phases (i.e., Needs Assessment, Scoping Assessment, Local Plan, or Integrated Regional Resource Plan).
- Identification of any new needs over the 2023-2033 period and wires plans to address these needs based on new and/or updated information.
- Consideration of long-term needs identified in the North & East of Sudbury IRRP, Bulk system studies or as identified by the TWG.

3. REGIONAL PLANNING PROCESS & RIP METHODOLOGY

3.1 Overview

Bulk System Planning, Regional Planning and Distribution Planning are the three levels of planning for the electricity system in Ontario. Bulk system planning typically looks at issues that impact the system on a provincial level and requires longer lead time and larger investments. Comparatively, planning at the regional and distribution levels look at issues on a more regional or localized level. Typically, the most essential and effective regional planning horizon is the near- to medium-term (1- 10 years), whereas long-term (10-20 years) regional planning mostly provides a future outlook with little details about investments because the needs and other factors may vary over time. On the other hand, bulk system plans are developed for the long term because of the larger magnitude of the investments.

The regional planning process begins with a Needs Assessment (NA) which is led by the transmitter to identify, assess, and document which of the needs

a) can be addressed directly between the customer and transmitter along with a recommended plan, and;
b) that require further regional coordination and identification of Local Distribution Companies (LDCs) to be involved in further regional planning activities for the region.

At the end of the NA, a decision is made by the Technical Working Group (TWG) as to whether further regional coordination is necessary to address some or all the regional needs. If no, further regional coordination is required, recommendation to implement the recommended option and any necessary investments are planned directly by the LDCs (or customers) and the transmitter. The Region's TWG can also recommend to the transmitter and LDCs to undertake a local planning process for further assessment when needs

a) are local in nature,
b) require limited investments in wires (transmission or distribution) solutions, and;
c) do not require upstream transmission investments.

If coordination at the regional or sub-regional levels is required for identified regional needs, then the Independent Electricity System Operator (IESO) initiates the Scoping Assessment (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 or resource alternatives, e.g., Conservation and Demand Management (CDM), Distributed Generation (DG), etc., in order to make a decision on the most appropriate regional planning approach including Local Plan (LP), Integrated Regional Resource Plan (IRRP) and/or Regional Infrastructure Plan (RIP).

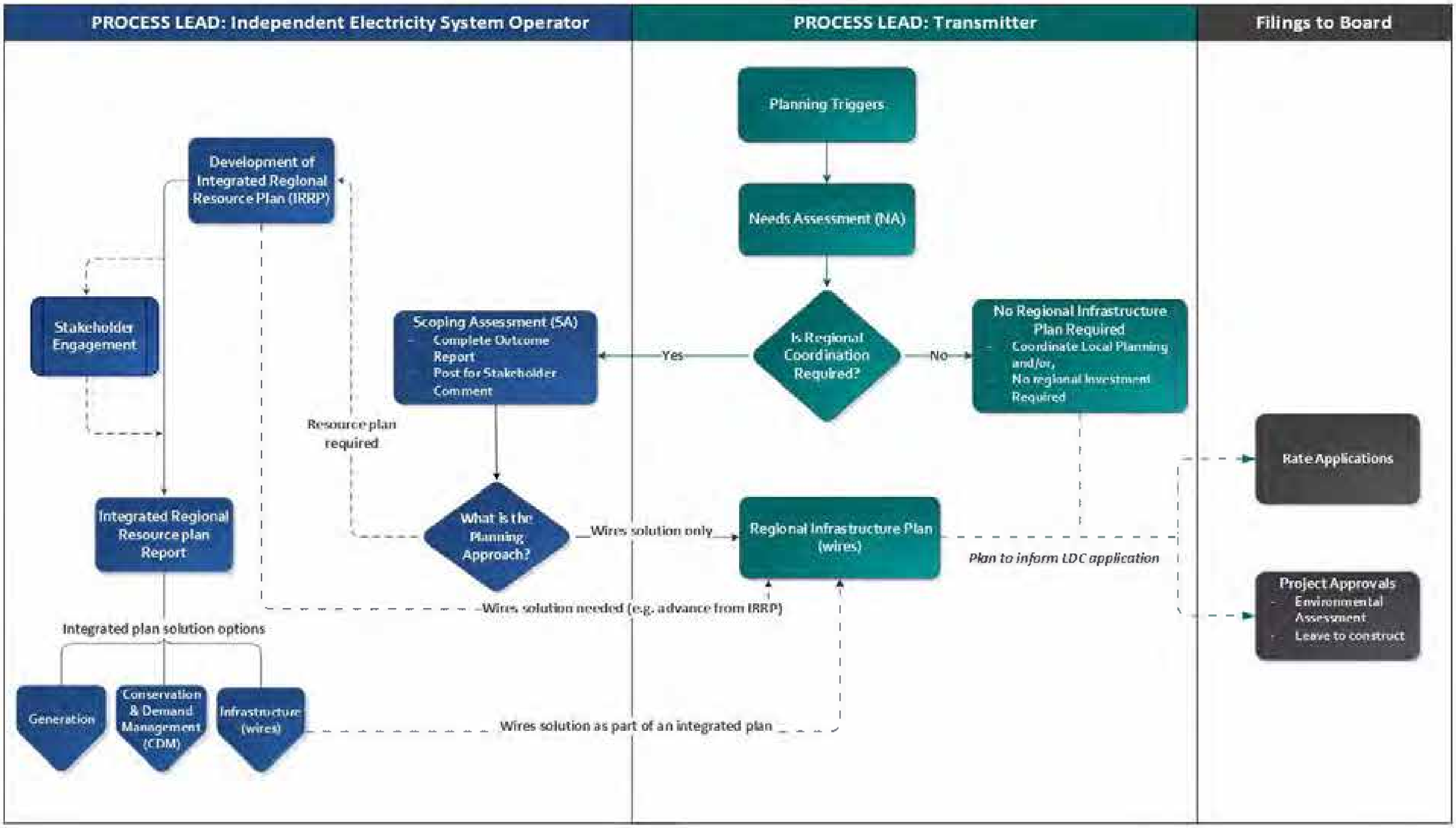
The primary purpose of the IRRP is to identify and assess both resource and wires options at a higher or macro level, but sufficient to permit a comparison of resource options vs. wire infrastructure to address the needs. Worth noting, the LDCs' CDM targets as well as contracted DG plans provided by IESO and LDCs are reviewed and considered at each step in the regional planning process.

If and when an IRRP identifies that resource and/or wires options may be most appropriate to meet a need, resource/wires planning can be initiated in parallel with the IRRP or in the RIP phase to undertake a more detailed assessment, develop specific resource/wires alternatives, and recommend a preferred wires solution.

The RIP phase is the 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 these needs. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive and consolidated 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 the LDC(s). Respecting the Ontario Energy Board (OEB) timeline provision of the RIP, planning level stakeholder engagement is not undertaken during this phase. However, stakeholder engagement at a project specific level will be conducted as part of the project approval requirement.

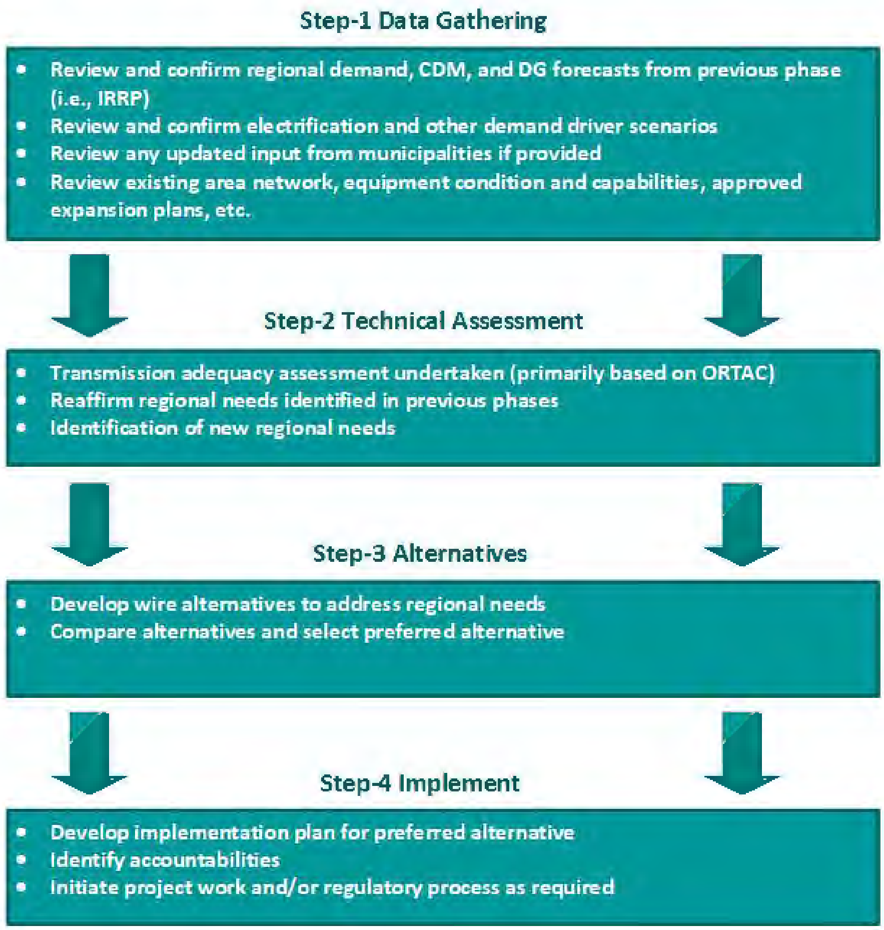
The various phases of Regional Planning Process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome are shown below in Figure-1.

Figure-1 Regional Planning Process Flowchart



3.2 Regional Infrastructure Plan Methodology

Figure-2 Regional Infrastructure Plan Methodology



Regional Infrastructure Plan phase is a four-step process which are described below:

3.2.1. Data Gathering:

The first step of the RIP process is the review of planning assessment data collected in the previous stages of the regional planning process. Hydro One collects this information and reviews it with the technical working group (TWG) 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. As agreed by TWG members, the load forecast from the IRRP was used for this RIP.

- Review and confirm electrification and other growth scenarios which effects the projects recommended in in previous stages and also update the inputs provided by the Municipalities.
- Existing area network and capabilities including any bulk system power flow assumptions.
- Other data and assumptions as applicable such as asset condition, load transfer capabilities, and previously committed transmission and distribution system plans.

3.2.2. Technical Assessment:

The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Additional near and medium-term needs may be identified at this stage.

3.2.3. Alternative Development:

The third step is the development of wires options to address the needs and determine a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact, and costs.

3.2.4. Implementation Plan:

The fourth and last step is the development of the implementation plan for the preferred alternative, identifying accountabilities and initiate project work or obtain permissions from Regulatory Commission if any.

4. REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The North & East of Sudbury Region are bounded by regions of North Bay, Timmins, Hearst, Moosonee, Kirkland Lake and Dymond. The geographical boundaries of the North & East of Sudbury region is shown in Figure 3 below.

Electrical supply for this region is provided through a network of 230kV and 115kV transmission circuits. This area is further reinforced through the 500kV circuits P502X and D501P connecting Hanmer TS to Pinard TS.

This region has the following four local distribution companies (LDC):

- Hydro One Networks (distribution)
- Northern Ontario Wires Inc
- Hearst Power Ltd
- North Bay Hydro Distribution Ltd.
- Greater Sudbury Hydro Inc.

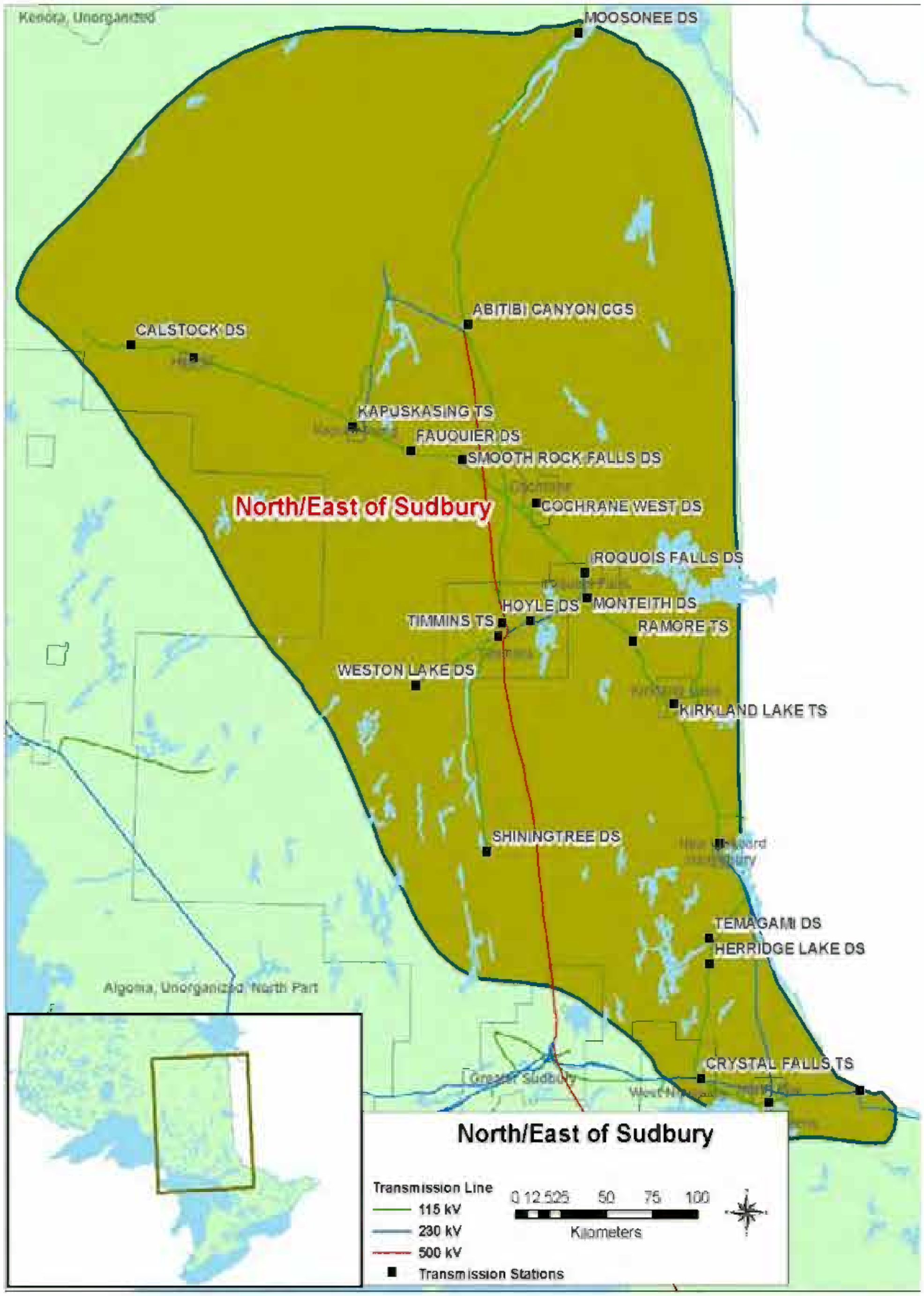


Figure 3: Map of North & East of Sudbury Regional Planning Area

The circuits and stations of the area are summarized in the Table 2 below:

Table 2: Transmission Station and Circuits in the North & East of Sudbury Region

115kV circuits	230kV circuits	Hydro One Transformer Stations	Generation Stations
A4H/A5H	D23G	Ansonville TS*	Otter Rapids GS
A8K/A9K	H22D	Crystal Falls TS	Abitibi Canyon GS
D2H/D3H	H23S/H24S	Dymond TS*	Empire CGS (10 MW)
H6T/H7T	K38S	Hearst TS	Martin's Meadows CGS (10 MW)
P13T/P15T	L20D	Hunta SS	Abitibi CGS (10 MW)
T7M/T8M	L21S	Kapuskasing TS	Long Lake CGS (10 MW)
D2L	P91G	Kirkland Lake TS	Kipling GS (164 MW)
H9K	R21D	Little Long SS	Kipling 2 GS (79 MW)
K2	W71D	Moosonee SS	Harmon GS (140 MW)
K4		North Bay TS	Harmon 2 GS (78 MW)
L1S		Otter Rapids SS	Smoky Falls 2 GS (264 MW)
L5H		Otto Holden TS*	Little Long GS (MW)
D3K		Pinard TS*	Little Long 2 GS (70 MW)
P7G		Porcupine TS*	A.P. Kapuskasing CGS (57 MW)
T61S		Ramore TS	Nagagami CGS (18 MW)
F1E		Spruce Falls TS	A.P. Calstock CGS (39 MW)
T2R		Timmins TS	Carmichael Falls CGS (18 MW)
		Trout Lake TS	Smooth Rock Fall CGS (8 MW)
		Widdifield SS	Yellow Falls CGS (16 MW)
			Iroq Falls Power CGS (126 MW)
			New Liskeard CGS (30 MW)
			Northland Power Kirkland Lake CGS (172 MW)

*Stations with Autotransformers installed

The single line diagram of the Transmission Network of North & East of Sudbury region is shown in Figure 4 below.

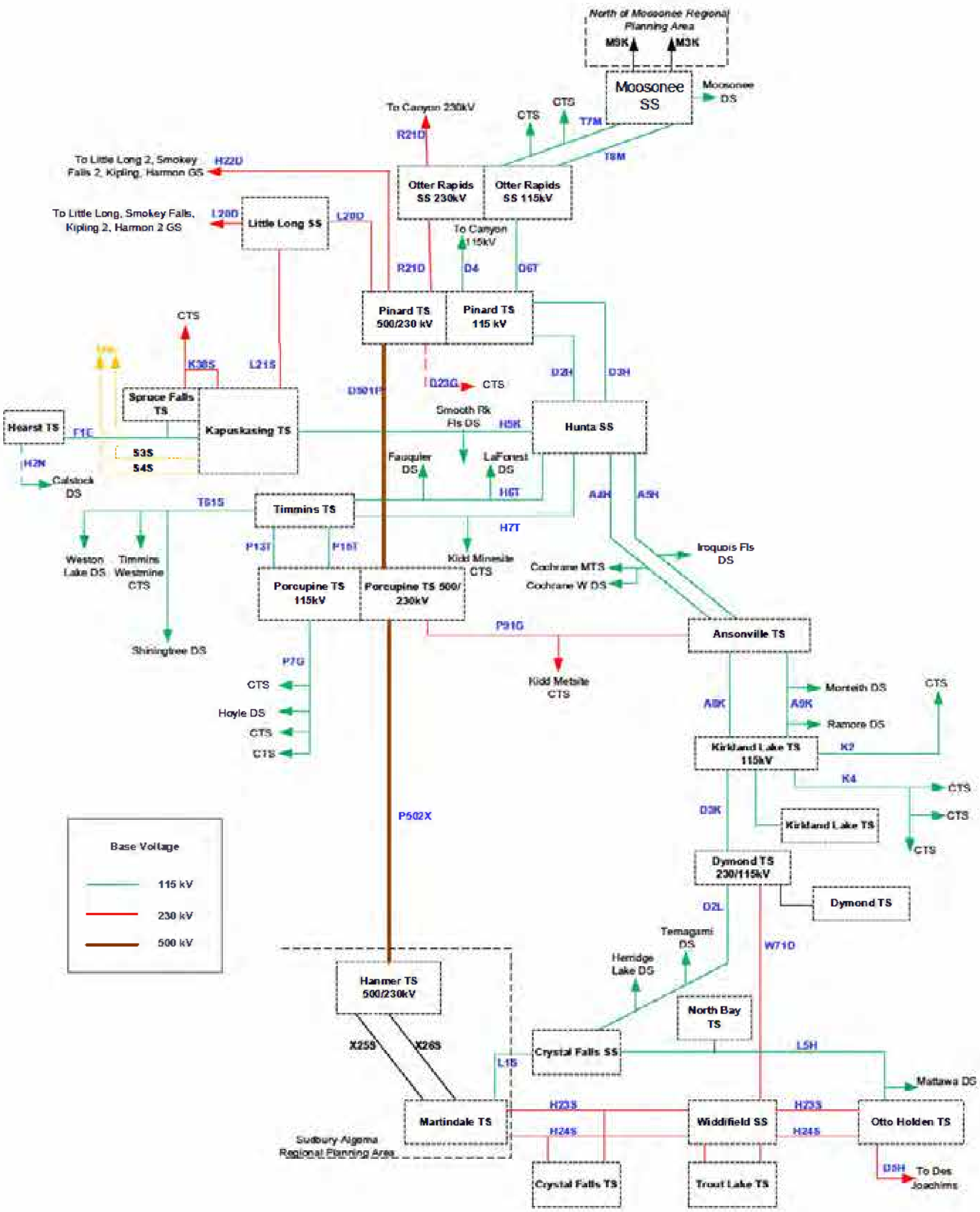


Figure 4: North & East of Sudbury Transmission Single Line Diagram

5. TRANSMISSION FACILITIES COMPLETED IN THE LAST TEN YEARS AND/OR ARE UNDERWAY

In this section a complete list of all the projects that are completed in past ten years or are currently underway is provided and are briefly discussed in the sub sections. As a part of this or previous Regional Planning Cycle(s), several “Major HV Transmission Projects” were recommended in the **North & East of Sudbury** Region to improve the supply capability and reliability.

Hydro One, being the only Transmission Asset Owner (TAO) in the region have undertaken execution of the projects recommended in the past ten years. A summary and brief description of all the projects completed or are currently underway is given below:

I. Following Major projects were completed during the last ten years:

- Kapuskasing Area Reinforcement – H9K Circuit Upgrade (ISD 2020)
- Kirkland Lake TS (T12/T13) transformer replacement (ISD 2017)
- Dymond TS (T3/T4) transformer replacement (ISD 2016)
- Timmins TS (T63/T64) replace with a single 83MVA (ISD 2016)

II. Following Major projects are underway:

- Kapuskasing Area Reinforcement – Install 115kV Reactive Devices (ISD 2023)
- Kirkland Lake TS – Replace low voltage breakers, Instrument Transformers, P&C equipment (ISD 2025)
- Hearst TS - Replace low voltage breakers, P&C Equipment, switches (ISD 2028)
- Hunta SS - Replace P&C Equipment (ISD 2025)
- Porcupine TS – Replace 1 - 500kV/230kV autotransformer (T7), 2- 500kV/115kV autotransformers (T3/T4), switches, station service and P&C equipment (ISD 2025)
- Otto Holden TS - Replace 2 – 230 kV/115 kV autotransformers (T3/T4), high voltage breakers, switches, station service equipment, and protections (ISD 2027)
- K4 circuit - Refurbish Kirkland Lake TS X Matachewan JCT (10km) (ISD 2024)
- A8K/A9K circuits – Refurbish A8K/A9K (90km) (ISD 2023)

Note: The planned in-service year for the above projects is tentative and is subject to change.

6. LOAD FORECAST AND STUDY ASSUMPTIONS

6.1. Load Forecast

The TWG participants reviewed and verified that there is no material change in load forecast from those used in the North & East of Sudbury Region IRRP Load Forecasts (April 2023). Thus, the IRRP forecasts were used in development of this Report. TWG participants, including representatives from LDC's, IESO and Hydro One, provided information and input for the IRRP Load forecast, which also includes the inputs from the Municipal Energy Plans (MEP) and/or Community Energy Plans (CEP). New industrial/mining load connections requests have been received after publication of IRRP report. These new potential load connections have not been explicitly listed in the load forecast tables, however these loads have been studied in the RIP to assess their impact to the area.

During the study period, the load in the North & East of Sudbury Region is expected to grow at an average annual rate of approximately 0.50% in winter and 0.25% in summer from 2023 to 2043. The Region is winter peaking, so this assessment is based on winter peak loads. This growth does not include significant increases in the industrial sector.

Figures 5 & 6 shows the North & East of Sudbury Region extreme summer/winter weather net coincident and non-coincident load forecast from 2023 to 2043. The load forecasts from the North & East of Sudbury Region were adopted as agreed to by the TWG. The load forecast shown is the regional non-coincident forecast, representing the sum of the load in the area for the step-down transformer stations.

Non-coincident and coincident forecast for the individual stations in the region is available in Appendix A and is used to determine any need for station capacity relief in the region.

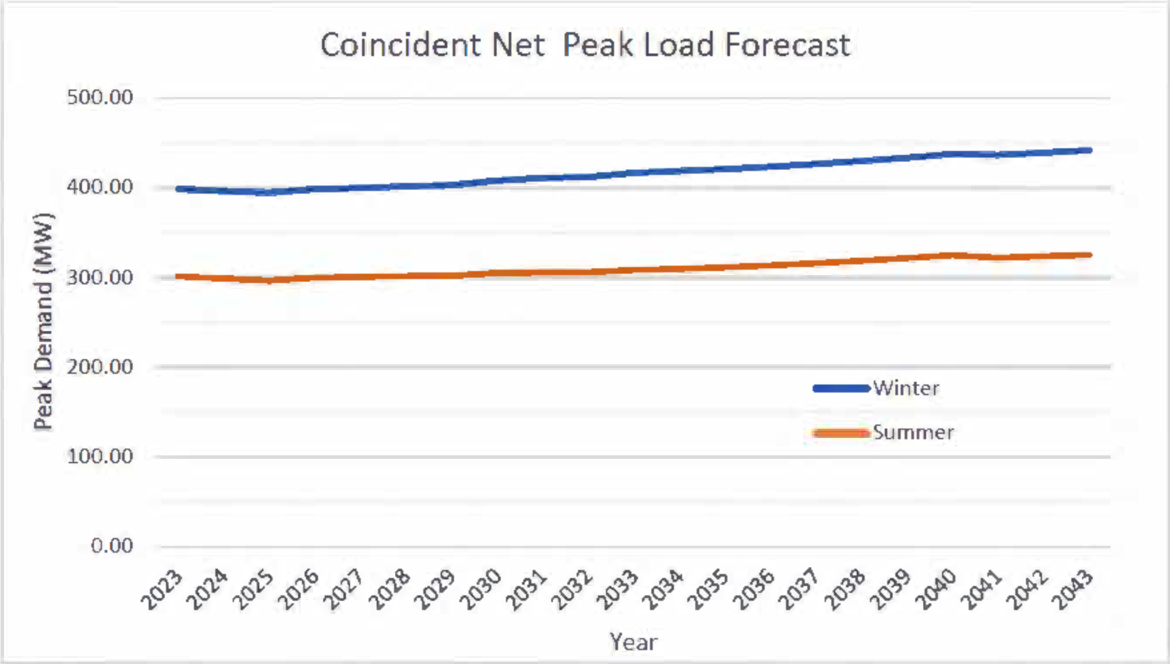


Figure 5: North & East of Sudbury Region summer/winter coincident Net Peak Load Forecast

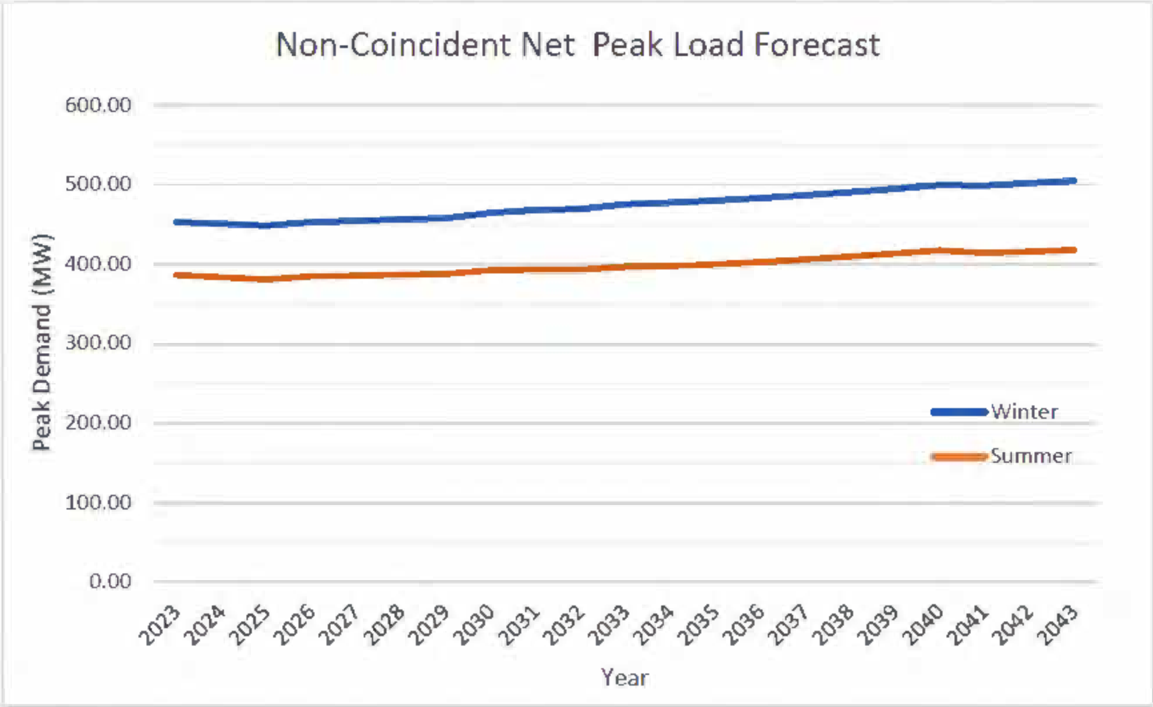


Figure 6: North & East of Sudbury Region summer/winter Non-coincident Net Peak Load Forecast

6.2. Other Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2023-2043.
- LDCs reconfirmed load forecasts up to 2040. The additional 3 years of forecasts were extrapolated based on the growth rate as a reasonable position to complete the 20-year period.
- All planned facilities for which work has been initiated and are listed in section 4 are assumed to be in-service.
- The Region is winter peaking, so this assessment is 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 and 95% lagging power factor for stations having low-voltage capacitor banks, or on the basis of historical power factor data.
- Normal planning supply capacity for transformer stations in the region is determined by the winter 10-day Limited Time Rating (LTR).
- Regional transmission line and auto transformer capacity adequacy is assessed by using coincident peak loads in the area. Capacity assessment for radial lines and stepdown transformer stations use non-coincident peak loads.
- Resources assumptions align with the ORTAC.

7. SYSTEM ADEQUACY AND REGIONAL NEEDS

This section reviews the adequacy of the existing Transmission Systems and Transformer Station facilities supplying the North & East of Sudbury Region and lists the facilities requiring reinforcement over the near and midterm period. The adequacy assessment assumes that all the projects that are currently underway, listed in **"Section 5"** are completed.

In current regional planning cycle, the following regional assessments were completed, and their findings were used as inputs to this RIP report:

- North & East of Sudbury Region Second cycle Needs Assessment Report, Completed in May 2021 by Hydro One
- North & East of Sudbury Region Second cycle Scoping Assessment Report, Completed in August 2021 by the IESO
- North & East of Sudbury Region Second cycle Integrated Regional Resource Plan Report, Completed in April 2023 by the IESO

The Technical Working Group identified several regional needs based on the forecasted load demand over the near to mid-term period in the reports mentioned above. The results of the Adequacy Assessment to define the needs are discussed in sub-sections "7.1 to 7.4" and a detailed description and status of plans to meet these needs are given in **"Section 8"** of this report.

7.1. Asset Renewal Needs for Major HV Transmission Equipment

In addition to the asset renewal needs identified in previous regional planning cycle, Hydro One and TWG has also identified new asset renewal needs for major high voltage transmission equipment that are expected to be replaced over the next 10 years in the **North & East of Sudbury** Region. The complete list of major HV transmission equipment requiring replacement in the **North & East of Sudbury** Region is provided in table 3 in this sub-section. Hydro One is the only Transmission Asset Owner (TAO) in the Region

Asset Replacement needs are determined by asset condition assessment. Asset condition assessment is based on a range of considerations such as:

- Equipment deterioration due to aging infrastructure or other factors,
- Technical obsolescence due to outdated design,
- Lack of spare parts availability or manufacturer support, and/or
- Potential health and safety hazards, etc.

The major high voltage equipment information shared and discussed as part of this process is listed below:

- 230/115kV autotransformers
- 230 and 115kV load serving step down transformers
- 230 and 115kV breakers where:
  replacement of six breakers or more than 50% of station breakers, the lesser of the two
- 230 and 115kV transmission lines requiring refurbishment where:
  Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like
- 230 and 115kV underground cable requiring replacement where:

Leave to Construct (i.e., section 92) approval is required for any alternative to like-for-like

Table 3: Major HV Transmission Asset assessed for Replacement in the region

Station/Circuit	Need Description	Planned ISD
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers.	2025
Hunta SS	Replacement of P&C and telecom equipment.	2027

Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment.	2026
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment.	2027
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment.	2030
Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections.	2028
Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections.	2030
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment.	2031
Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment.	2032
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment.	2031
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters.	2033
K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km)	2024
T61S	Replace conductor and refurbish circuit Timmins TS x Shiningtree JCT (115km)	2024
K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km)	2024
D2H/D3H*	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km)	2029
A4H/A5H**	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km)	2027

Note: The planned in-service year for the above projects is tentative and is subject to change.

* IESO to inform by end of Q2 2025 if an upgrade is required

** IESO to inform by end of 2024 if an upgrade is required

7.2. Station Capacity Needs

Over the study period [2023-2043] RIP reviewed the capacity of all the 230kV and 115kV Transforming stations within the North & East of Sudbury Region. The NA and IRRP studies had previously indicated that the following stations require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast, the stations which require capacity relief during the study period are shown in Table 4 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 4: North & East of Sudbury Region Station Capacity Needs in the study period

Station Name	Capacity (MW)	2023 Loading (MW)	Station 10 day LTR (MW)	Need Date
Ramore TS	15	12	15	2033

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.3. Transmission Line Capacity Needs

Over the study period [2023-2033] RIP reviewed the capacity of all the 230kV and 115kV Transmission lines within the North & East of Sudbury Region. The NA and IRRP studies had previously indicated that the following Transmission lines require capacity relief within the study period. This RIP has further confirmed those needs and based on the load forecast and following contingencies, the Transmission lines which require capacity relief during the study period are shown in Table 5 below. The need timeframe defines the time when the peak load forecast exceeds the most limiting seasonal (summer or winter) Limited Time ratings.

Table 5: North & East of Sudbury Region Transmission Line Capacity Needs in the study period

Sr.no.	Name of Circuit	Name of Section	Contingency	Need Date
1	D3K	Dymond x Kirkland Lake	N-1-1 (AxK O/S + loss of companion circuit)	2030

The options and preferred solutions to address these needs are discussed further in Section 8 of the report.

7.4. System Reliability, Operation and Load Restoration Needs

Load security and load restoration needs were reviewed as part of the current study. The ORTAC Section 7 requires that no more than 600 MW of load be lost as a result of a double circuit contingency.

Further, loads are to be restored in the restoration times[1] specified as follows:

- All loads must be restored within 8 hours.
- Load interrupted in excess of 150 MW must be restored within 4 hours.
- Load interrupted in excess of 250 MW must be restored within 30 minutes.

The post contingency voltage control issues have also been listed in Table 6 below.

Table 6: North & East of Sudbury Region System Operational Needs and Voltage Control in the study period

Sr.no.	Reliability / Operational Need	Description	Need Date
1	Dymond TS	Voltage control violations when switching existing 115kV Dymond TS capacitor banks	2030
2	Kirkland Lake TS	Voltage control challenges in Kirkland Lake area during concurrent outages to Kirkland Lake TS SVC and Northland Power Kirkland Lake GS.	2030
3	Ansonville, Hunta, Kapuskasing	Post contingency voltage control challenges for the loss of Ansonville T2 and Canyon Units.	Existing

[1] These approximate restoration times are intended for locations that are near staffed centers. In more remote locations, restoration times should be commensurate with travel times and accessibility

4	ORTAC load security criteria not met for 500 kV circuit outages	Loss of load and resources during outages to any of the two major 500kV transmission lines in the Northeast	Existing
5	Difficulty supplying loads during planned outages to circuit D501P	Area loads cannot be adequately supplied during planned circuit outages	Existing

8. REGIONAL PLANS

This section discusses the regional electric supply needs and presents all the wires alternatives considered to address these needs and identifies the best and preferred wires solutions for the North & East of Sudbury Region. These needs include those previously identified in the NA and IRRP for the North & East of Sudbury Region as well as any new needs identified during the RIP phase. All estimated costs included in the alternative analysis are considered as planning budgetary estimates and are used for comparative purposes only and may vary. The Needs in the region are summarized below in Table 6 below:

8.1 Asset Renewal Needs for Major HV Transmission Equipment

The Asset renewal assessment considers the following options for "right sizing" the equipment:

- Maintaining the status quo
- Replacing equipment with similar equipment with *lower* ratings and built to current standards
- Replacing equipment with similar equipment with *lower* ratings and built to current standards by transferring some load to other existing facilities
- Eliminating equipment by transferring all the load to other existing facilities
- Replacing equipment with similar equipment and built to current standards (i.e., "like-for-like" replacement)
- Replacing equipment with higher ratings and built to current standards

From Hydro One's perspective as a facility owner and operator of its transmission equipment, do nothing is generally not an option for major HV equipment due to safety and reliability risk of equipment failure. This also results in increased maintenance cost and longer duration of customer outages.

8.1.1. Asset Name – Location

Table 7: Needs identified in the region

Station/Circuit	Need Description	Planned ISD
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers. This investment will replace equipment that is in poor condition and deemed end of life.	2025
Hunta SS	Replacement of P&C and telecom equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2025
Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment. This investment will replace end of life transformers to reduce the risk of interruptions caused by transformer asset failure.	2026
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment. This investment will replace equipment that is in poor condition and deemed end of life. It will also replace end of life transformers to reduce the risk of interruptions caused by transformer asset failure. The new transformers will be installed in a greenfield location and connected to the existing 230kV bus at Holden CGS via a 230 conductor/bus. The replacement transformers and associated equipment will be constructed within the limits of a new station called Antonie TS	2027
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2028

Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections. This investment will replace equipment that is in poor condition and deemed end of life. It will also help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2028
Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections. This investment will replace equipment that is in poor condition and deemed end of life.	2030
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2031
Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment. This investment will replace equipment that is in poor condition and deemed end of life.	2031
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment. This investment will replace equipment that is in poor condition and deemed end of life. It will also help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2031
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters. This investment will replace equipment that is in poor condition and deemed end of life. It will also help maintain reliability of supply to area customers and reduce the risk of interruptions caused by transformer asset failure.	2033
A8K/A9K	Replace conductor and refurbish circuit Ansonvillle x Kirkland Lake (180km) This investment will replace the conductor and also increase the thermal capacity to meet system needs.	2023

K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km) This investment will replace the conductor with a like for standard conductor. Right sizing has been taken into consideration to meet supply capacity of loads on the line.	2024
T61S	Replace conductor and refurbish circuit Timmins TS x Shining tree JCT (115km) This investment will replace the conductor with a like for standard conductor. Right sizing has been taken into consideration to meet supply capacity of loads on the line.	2024
K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km) This investment will replace the conductor with a like for standard conductor. Right sizing has been taken into consideration to meet supply capacity of loads on the line.	2024
D2H/D3H	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km) This investment will replace the conductor with a like for standard conductor.	2029
A4H/A5H	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km) This investment will replace the conductor with a like for standard conductor.	2027

8.2 Station Capacity Needs

A Station Capacity assessment was performed over the study period [2023-2043] for the 230kV and 115kV Transforming stations in the North & East of Sudbury Region using either the summer or winter peak load forecasts that were provided by the study team. Based on the results, the following Station capacity needs have been identified in the during the study period:

8.2.1 Ramore TS

Ramore TS is a single transformer 115/27.6kV 17MVA station. The summer and winter 10-Day LTR is 15MW, and load at this station is expected to exceed the LTR in 2033.

Table 8: Ramore TS Load Forecast

Station	LTR (MW)	Load Forecast										
		2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Ramore TS	15	13.7	13.8	13.9	14	14.2	14.3	14.4	14.8	14.9	15	15.1

The following alternatives were considered to address Ramore TS capacity need:

Alternative 1 - Maintain Status Quo: Ramore TS will continue to operate with the existing installed capacity, and Hydro One will monitor load growth to ensure supply needs are met.

Alternative 2 – Replace T1 with a new 115/27.6 42MVA unit: Replacing T1 with the next largest standard size unit will increase the station LTR to 38MW. The station LTR will remain limited to the size of the transformer as there will still only be a single unit installed at the station. This was considered and rejected as this would result in additional cost of approximately $10M and prematurely retire T1 transformer. This transformer remains in acceptable condition and is not scheduled to be replaced by Hydro One within the study period due to end-of-life needs.

The TWG recommends Alternative 1 as the preferred and cost effective alternative for addressing the need. The capacity need will arise in 2033 and will allow both Hydro One and area LDCs to monitor load growth and take corrective action when needed. This need will also be refreshed in the next cycle or regional planning.

8.3 Transmission Lines Capacity Needs

All line and equipment loads shall be within their continuous ratings with all elements in service and within their long-term emergency ratings with any one element out of service. Immediately following contingencies, lines may be loaded up to their short-term emergency ratings where control actions such as re-dispatch, switching, etc. are available to reduce the loading to the long-term emergency ratings. A Transmission Lines Capacity Assessment was performed over the study period [2023-2043] for the 230kV and 115kV Transmission line circuits in the North & East of Sudbury Region by assessing thermal limits of the circuit and the voltage range as per ORTAC to cater this need. Based on the results, the following line capacity needs have been identified in the during the study period:

No new line capacity needs have been identified in this planning cycle.

8.3.1 D3K (Thermal Violation)

D3K is a single circuit 115kV transmission line which provides a critical network path between Dymond TS and Kirkland Lake TS. This circuit is approximately 80km in length and serves to provide connection to generating stations and provide a path for network flows. Sections of this line will start to experience supply capacity violations at the end of the study period and will require mitigating solutions to allow for increased flows. The circuit section is described below;

1. Dymond TS x Kirkland Lake TS (80km) – For the loss of A8K and A9K, the companion circuit will exceed its Long-Term Emergency (LTE) rating. As studied in the IRRP and verified in the RIP this is expected to occur as early as 2030 based on demand forecast.

Solutions to address these needs will be further explored in future planning cycles given the long-term nature of this need. Flows on this line and its violations are heavily influenced by area resource assumptions, and demand forecast for customers in the Kirkland Lake area. In addition, a new Kirkland Lake RAS (Remedial Action Scheme) has been installed to initiate control actions such as load rejection for system contingencies. Currently, this RAS will trip loads and avoid the D3K thermal violation. This scheme will continue to be utilized by control room operators and it is expected that reliance on this scheme will gradually be reduced as system upgrades and replacements are complete in the future. The TWG will continue to monitor this need in future planning cycles and initiate an investment should this violation be advanced due to changing system conditions.

8.4 System Reliability, Operation and Restoration Needs

The transmission system must be planned to satisfy demand levels up to the extreme weather, median-economic forecast for an extended period with any one transmission element out of service. A study has been performed, considering the net coincident load forecast and the loss of one element over the study period [2023-2043] to cater this need**.**

8.4.1 Dymond TS – Voltage Control

IESO operations team has reported voltage violations at Dymond TS during capacitor bank switching. Dymond TS has two 115kV shunt capacitor banks (SC11/SC12) each rated at 24MVar. IESO has observed that switching the banks under certain system conditions voltages can exceed the maximum voltage and step change permitted by IESO Market Rules. These violations are largely dependent on system configuration (W71D O/S + Loss of D3K) and less sensitive to area loading patterns. Voltage violations are not observed during system conditions where all elements are In-service, or one element is O/S as there is sufficient reactive support from adjacent stations to support Dymond pre-contingency.

Alternative 1 - Maintain Status Quo: IESO and Hydro One operations will continue to control the system with other reactive devices in the northeast. The existing capacitor banks can continue to be utilized to help meet single contingency planning scenarios.

Alternative 2 – De-rate the Existing capacitor banks (SC11/SC12) Hydro One can de-rate the capacitor bank between 14-16MVar to ensure voltage limits upon cap bank switching remain within acceptable limits. This option helps with operations primarily for a W71D+D3K contingency. This option reduces the total var support at Dymond by 50% and due to the de-rating in size. It has been discussed with the TWG that operations may have to rely on other reactive devices in the northeast to provide steady state voltage support for other system configurations.

The TWG recommends to continue to investigating the need to a de-rate the existing capacitor banks and provide enhanced automation and visibilty.

8.4.2 Kirkland TS – Voltage Control

IESO has reported difficulties in maintaining adequate system voltages in the Kirkland Lake area during outage conditions. Concurrent outages to the Kirkland Lake SVC and Northland Power Kirkland Lake Generating facility result in declining voltages at the end of the radial K2 transmission line.

Kirkland Lake TS presently has a 115kV connection SVC, and shunt capacitor bank to help maintain voltages during steady state, and contingencies.

K2 circuit is a radial line with multiple industrial customers tapped of this circuit. Voltage performance on this circuit is directly attributed to the load pattern of these customers. It is expected that future loads connecting to this circuit will be required to maintain their voltage within reasonable limits as a condition to connect. A new Kirkland Lake RAS is also available to address thermal and voltage violations in the area as a control action and can be expanded to include additional inputs and outputs. Planning level cost for a new 115kV capacitor bank will cost between $10M-$15M, and will be largely influenced by the available space at the station and the control building.

The TWG recommends to monitor the voltage performance at Kirkland Lake TS bus and ensure that voltages on the K2 delivery points remain within reasonable limits. Hydro One and IESO will engage in further discussion on system operating limits, and resource options to mitigate this finding.

8.4.3 Ansonville, Hunta, Kapuskasing Voltage Control

Voltage violations at Ansonville TS, Hunta TS, and Kapuskasing TS can occur for the loss of Ansonville T2 and Abitibi Canyon generating units. This is coupled with the general challenge of maintaining system voltages within acceptable limits in the northeast as a whole. A new Kirkland Lake RAS (remedial action scheme) has been installed to help operators take control actions for system contingencies. This RAS can also be expanded to accommodate changing system needs which will help to provide operating flexibility in the future. Kapuskasing RAS will also be installed to provide voltage support in the Kapuskasing area for system contingencies. This RAS can also be expanded when needed to meet future system needs.

Porcupine SVC will also be refurbished in the planning cycle and will provide much needed reactive support for the northeast.

The TWG will continue to address voltage control issues as needed to accommodate system needs. IESO and Hydro One continues to work towards finding robust solutions that provide voltage support without over reliance on load rejection and other adverse control actions. No additional investments are required from this regional infrastructure plan to address this need.

8.4.4 ORTAC load security criteria not met for 500 kV circuit outages

The North & East of Sudbury region is supplied by two 500 kV circuits, P502X from Hanmer TS to Porcupine TS and D501P from Porcupine TS to Pinard TS.

The system connects substantial amount of hydroelectric generation on the Moose River and loads in the region. The planning requirement to respect the loss of either of the 500kV circuits results in the need to rely on a Remedial Action Scheme (RAS), the Northeast Load and Generation Rejection Scheme (the "Northeast LGR"), that enables full use of the scheme following the loss of a single transmission element.

This is a legacy system that does not meet today's planning criteria for the use of load rejection following the loss of a single transmission element. However, bringing it up to current standards would involve substantial capital investment that is difficult to justify without the introduction of new needs. Future bulk projects such as the new 230kV line between Porcupine TS and Wawa TS will help to reduce reliance on area RASs following a P502X outage, however, does not address the loss of D501P and will still result in load rejection for area customers. The Working Group (TWG) recommends that the next bulk system plan in Northeast Ontario address the load security concerns following an outage on D501P and develop a plan to proactively reduced reliance on RAS.

8.4.5 Difficulty supplying loads during planned outages to circuit D501P

IESO's outage planning staff have also identified that during recent outages to D501P, it has not been possible to supply all customer load in the area due to limitations on the 115 kV system, and certain industrial customers have been forced to reduce their production. These concerns have also been raised by these customers themselves. During D501P outages, generation must also be significantly curtailed, which can remove substantial capacity from the Ontario system.

Hydro One recently implemented a protection scheme to allow D501P outages and working to address the shortfalls experienced during the implementation. TWG recommends to continue discussions with Hydro One and IESO operation to ensure future projects can be completed effectively during 500kV outages and the project team will work to develop effective solutions for the specific projects in question. These solutions may include modifications/additions to area RASs schemes or new transmission facilities.

8.5 Long Term Considerations

Like many other regions in Ontario, load growth in North & East of Sudbury region will be directly impacted by new energy policies specifically those which help drive electrification. In addition, it is anticipated large market participants will also have incentive programs to modify operations/technologies to reduce greenhouse emissions. Details of how future programs will impact demand is unknown at this time thus the TWG will continue to monitor these trends throughout planning cycles to identify areas in need of investment. Future connection requests in the region will be assessed as needed to determine system requirements.

9. CONCLUSION AND RECOMMENDATION

This section concludes the Regional Infrastructure Plan Report for North & East of Sudbury Region. The Major Infrastructure investments recommended by the TWG in the near and mid-term planning horizon [2023-2033] are provided in Table 7 below, along with their planned in-service dates (ISD) and budgetary estimates for planning purposes.

Table 9: Recommended Plans over the next 10 Years

Station/Circuit Name	Recommended Plan	Lead	Planned ISD	Cost ($M)
Asset Renewal Needs				
Kirkland Lake TS	Replacement of Instrument Transformers, P&C equipment, station service equipment and low voltage circuit breakers.	Hydro One Transmission	2025	36
Hunta SS	Replacement of P&C and telecom equipment.	Hydro One Transmission	2025	12
Porcupine TS	Replacement of 1-500/230kV 360MVA autotransformer (T8), 2- 500/115kV 225MVA autotransformers (T3/T4), switches, station service equipment and P&C equipment.	Hydro One Transmission	2026	91
Otto Holden TS	Replacement of 2-230/115 kV 60MVA autotransformers (T3/T4), high voltage circuit breakers, switches, station service equipment, and P&C equipment.	Hydro One Transmission	2027	74
Hearst TS	Replacement of low voltage circuit breakers, switches, P&C Equipment.	Hydro One Transmission	2028	19
Timmins TS	Replacement of 1-115/27.6kV 83MVA (T2) transformer and associated protections.	Hydro One Transmission	2028	14
Kapuskasing TS	Replace low voltage circuit breakers, switches, station service equipment and protections.	Hydro One Transmission	2030	24
Dymond TS	Replacement of low voltage breakers, and associated P&C equipment.	Hydro One Transmission	2031	42

Ansonville TS	Replace P&C equipment, Instrument transformers, station service equipment.	Hydro One Transmission	2031	11
Crystal Falls TS	Replacement of 2-230/44kV 42MVA (T5/T6) transformers, station service equipment, switches and P&C equipment.	Hydro One Transmission	2031	32
Trout Lake TS	Replacement of 2–230/44 kV 125MVA (T3/T4) transformers, low voltage circuit breakers and surge arresters.	Hydro One Transmission	2033	17
K4	Replace conductor and refurbish circuit Kirkland Lake TS X Matachewan JCT (10km)	Hydro One Transmission	2024	4
T61S	Replace conductor and refurbish circuit Timmins TS x Shiningtree JCT (115km)	Hydro One Transmission	2024	
K1/K2	Replace conductor and refurbish circuit Kirkland Lake TS x American Barrick JCT (14km)	Hydro One Transmission	2024	4
D2H/D3H*	Replace conductor and refurbish circuit Hunta SS x Abitibi Canyon SS (183km)	Hydro One Transmission	2029	96
A4H/A5H**	Replace conductor and refurbish circuit Tunis JCT x Fournier JCT (47km)	Hydro One Transmission	2027	22
Station Capacity Needs				
Ramore TS	To be monitored and reviewed in next planning cycle	Hydro One Distribution	NA	NA
Transmission Line Capacity Needs				
D3K	Monitoring & further exploration in future RIP cycle	Hydro One Transmission	NA	NA
System Reliability, Operation and Load restoration Needs				
Dymond TS	Continue investigating to correctly size the existing 115kV SC11 & SC12 capacitor banks	Hydro One Transmission	NA	NA

Note:

a) The planned in-service dates are tentative and subject to change

b) Cost are based on budgetary planning estimates and excludes the cost for distribution infrastructure (if required)

* IESO to inform by end of Q2 2025 if an upgrade is required

** IESO to inform by end of 2024 if an upgrade is required

10. REFERENCES

[1] Independent Electricity System Operator, Ontario Resource and Transmission Assessment Criteria (issue 5.0 August 22, 2007)

[2] Ontario Energy Board, Transmission System Code (issue July 14, 2000 rev. December 18, 2018)

[3] Ontario Energy Board, Distribution system Code (issue July 14, 2000 rev. October 1, 2022)

[4] Ontario Energy Board, Load Forecast Guideline for Ontario (issue October 13, 2022)

Appendix A: Extreme Winter Weather Adjusted Net Load Forecast

Table A.1: North & East of Sudbury Region – Winter Coincident- Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Net Extreme Winter Weather Station Peak Demand Forecast, Coincident to NE of Sudbury Region (MW)																				
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	53.60	48.24	19.94	20.19	20.23	20.28	20.31	20.37	20.38	23.70	25.18	25.31	25.47	25.65	25.84	26.16	26.42	26.70	26.97	27.24	28.59	29.11	29.62
Hearst TS	T4	39.60	35.64	18.39	18.37	18.36	18.37	18.37	18.39	18.38	18.38	18.36	18.34	18.34	18.36	18.39	18.44	18.51	18.60	18.68	18.76	18.59	18.61	18.62
Kapuskasing TS	T5/T6	106.50	95.85	5.88	5.84	5.81	5.79	5.76	5.74	5.70	5.68	5.64	5.61	5.59	5.57	5.56	5.56	5.58	5.60	5.62	5.64	5.52	5.50	5.48
Kirkland Lake TS	T12/T13	57.60	51.84	40.32	40.24	40.21	40.21	40.18	40.19	40.19	40.22	40.17	40.11	40.11	40.12	40.14	40.16	40.26	40.38	40.50	40.62	40.34	40.35	40.36
North Bay TS	T1/T2	64.10	57.69	25.16	24.02	22.88	23.27	23.71	24.14	24.57	25.01	25.43	25.83	26.25	26.69	27.16	27.65	28.14	28.63	29.13	29.63	29.41	29.78	30.14
Ramone TS	T1	20.90	18.81	12.36	12.44	12.51	12.58	12.71	12.83	12.94	13.27	13.38	13.47	13.58	13.70	13.84	13.98	14.12	14.26	14.41	14.56	14.66	14.79	14.93
Timmins TS	T2/T4	113.10	101.79	52.77	52.81	52.92	53.09	53.22	53.42	53.58	53.78	53.87	53.93	54.09	54.28	54.48	54.69	55.03	55.41	55.78	56.16	55.85	56.04	56.22
Dymond TS	T3/T4	62.00	55.80	30.82	30.79	30.80	30.84	30.87	30.94	30.96	31.01	31.01	30.98	33.88	33.93	34.00	34.08	34.23	34.40	34.57	34.73	35.13	35.42	35.71
Trout Lake	T3/T4	209.50	188.55	98.85	97.86	96.96	100.18	100.79	101.50	102.00	102.58	103.32	103.85	104.79	105.56	106.38	107.38	108.51	109.69	110.87	113.07	112.08	112.92	113.76
Calstock DS	-	-	-	5.29	5.28	5.29	5.30	5.31	5.33	5.35	5.37	5.38	5.38	5.40	5.41	5.43	5.44	5.47	5.50	5.53	5.57	5.54	5.56	5.57
CochraneMTS	-	-	-	11.46	11.39	11.34	11.28	11.22	11.16	11.10	11.05	10.99	10.92	10.88	10.84	10.81	10.79	10.79	10.79	10.79	10.79	10.62	10.58	10.53
Cochran West DS	-	-	-	3.55	3.55	3.56	3.57	3.58	3.59	3.59	3.60	3.61	3.61	3.62	3.63	3.65	3.66	3.69	3.71	3.74	3.76	3.74	3.75	3.76
Fauquier DS	-	-	-	2.08	2.09	2.10	2.11	2.12	2.13	2.14	2.15	2.16	2.17	2.18	2.19	2.20	2.22	2.24	2.26	2.28	2.30	2.29	2.30	2.31
Herridge Lake DS	-	-	-	3.41	3.42	3.43	3.45	3.46	3.47	3.49	3.50	3.51	3.52	3.53	3.54	3.56	3.58	3.61	3.64	3.66	3.69	3.67	3.69	3.70
Hoyle DS	-	-	-	7.05	7.06	7.07	7.08	7.09	7.12	7.13	7.15	7.15	7.16	7.17	7.19	7.22	7.25	7.28	7.33	7.37	7.41	7.37	7.39	7.41
Iroquois Falls DS	-	-	-	5.19	5.16	5.15	5.13	5.11	5.09	5.07	5.06	5.03	5.01	5.00	4.99	4.98	4.98	4.98	4.99	5.00	5.01	4.94	4.93	4.91
Laforest Road DS	-	-	-	12.79	12.80	12.83	12.87	12.90	12.95	12.99	13.03	13.06	13.07	13.11	13.16	13.21	13.27	13.35	13.45	13.54	13.64	13.55	13.60	13.65
Mattawa DS	-	-	-	5.06	5.07	5.09	5.11	5.13	5.15	5.17	5.19	5.20	5.21	5.23	5.26	5.28	5.31	5.35	5.39	5.43	5.47	5.45	5.47	5.49
Monteith DS	-	-	-	2.93	2.94	2.96	2.97	2.99	3.00	3.02	3.03	3.04	3.05	3.06	3.08	3.10	3.12	3.15	3.18	3.21	3.23	3.22	3.23	3.25
Moosonee DS	-	-	-	14.31	14.31	14.33	14.37	14.40	14.45	14.48	14.53	14.55	14.56	14.59	14.63	14.68	14.74	14.82	14.91	15.00	15.09	15.01	15.05	15.09
Shiningtree DS	-	-	-	3.95	3.94	3.94	3.93	3.93	3.93	3.94	3.94	3.94	3.93	3.93	3.93	3.93	3.94	3.95	3.96	3.98	3.99	3.96	3.96	3.96
Smooth Rock Falls DS	-	-	-	1.80	1.80	1.80	1.81	1.81	1.81	1.81	1.82	1.82	1.82	1.82	1.82	1.82	1.83	1.84	1.85	1.86	1.87	1.85	1.86	1.86
Temagami DS 2	-	-	-	1.39	1.40	1.40	1.41	1.42	1.43	1.44	1.45	1.46	1.47	1.48	1.49	1.50	1.51	1.53	1.54	1.56	1.58	1.57	1.58	1.59
Verner DS	-	-	-	5.93	5.93	5.94	5.95	5.96	5.97	5.97	5.97	5.97	5.97	5.98	5.99	6.00	6.03	6.06	6.09	6.13	6.16	6.11	6.12	6.13
Warren DS	-	-	-	7.10	7.09	7.09	7.10	7.10	7.11	7.11	7.11	7.10	7.10	7.10	7.11	7.12	7.14	7.17	7.21	7.24	7.28	7.21	7.22	7.23

Table A.2: North & East of Sudbury Region – Winter non-Coincident – Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Winter Weather Station Non Coincident to NE of Sudbury Region (MW)																				
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	53.60	48.24	29.98	30.36	30.42	30.49	30.54	30.63	30.65	35.63	37.87	38.06	38.30	38.57	38.86	39.34	39.74	40.15	40.56	40.96	42.99	43.77	44.55
Hearst TS	T4	39.60	35.64	20.41	20.38	20.38	20.39	20.38	20.40	20.39	20.39	20.37	20.35	20.36	20.38	20.41	20.46	20.54	20.64	20.73	20.82	20.63	20.65	20.67
Kapuskasing TS	T5/T6	106.50	95.85	14.72	14.62	14.55	14.49	14.40	14.35	14.27	14.21	14.12	14.03	13.98	13.95	13.92	13.92	13.96	14.01	14.07	14.12	13.80	13.76	13.72
Kirkland Lake TS	T12/T13	57.60	51.84	40.90	40.82	40.79	40.79	40.75	40.77	40.77	40.79	40.75	40.68	40.68	40.69	40.71	40.73	40.83	40.95	41.08	41.20	40.92	40.93	40.94
North Bay TS	T1/T2	64.10	57.69	33.17	31.67	30.16	30.68	31.26	31.83	32.39	32.98	33.53	34.05	34.61	35.20	35.82	36.45	37.10	37.75	38.41	39.06	38.78	39.26	39.74
Ramone TS	T1	20.90	18.81	13.76	13.85	13.93	14.01	14.16	14.29	14.42	14.78	14.90	15.00	15.12	15.26	15.41	15.57	15.73	15.89	16.05	16.21	16.33	16.48	16.62
Timmins TS	T2/T4	113.10	101.79	54.22	54.26	54.38	54.55	54.68	54.89	55.05	55.25	55.35	55.41	55.58	55.77	55.98	56.20	56.55	56.93	57.32	57.70	57.38	57.58	57.77
Dymond TS	T3/T4	62.00	55.80	39.70	39.66	39.66	39.72	39.75	39.84	39.88	39.94	39.93	39.90	43.63	43.70	43.78	43.89	44.08	44.30	44.52	44.73	45.25	45.62	45.99
Trout Lake	T3/T4	209.50	188.55	101.32	100.30	99.38	102.68	103.31	104.03	104.54	105.14	105.90	106.44	107.40	108.19	109.03	110.05	111.22	112.43	113.63	115.89	114.88	115.74	116.59
Calstock DS	-	-	-	8.76	8.75	8.77	8.79	8.80	8.83	8.86	8.91	8.92	8.92	8.95	8.97	9.00	9.01	9.06	9.11	9.17	9.23	9.18	9.21	9.24
CochraneMTS	-	-	-	12.77	12.69	12.63	12.57	12.50	12.44	12.37	12.31	12.25	12.17	12.12	12.08	12.05	12.02	12.02	12.02	12.03	12.03	11.83	11.79	11.74
Cochran West DS	-	-	-	3.71	3.72	3.72	3.73	3.74	3.76	3.76	3.77	3.78	3.78	3.79	3.80	3.82	3.84	3.86	3.89	3.91	3.94	3.91	3.92	3.94
Fauquier DS	-	-	-	2.22	2.23	2.24	2.25	2.26	2.28	2.28	2.29	2.30	2.31	2.32	2.33	2.35	2.37	2.39	2.41	2.43	2.45	2.44	2.45	2.46
Herridge Lake DS	-	-	-	4.00	4.01	4.02	4.03	4.05	4.07	4.08	4.10	4.11	4.12	4.13	4.15	4.17	4.19	4.22	4.26	4.29	4.32	4.30	4.32	4.34
Hoyle DS	-	-	-	8.88	8.88	8.89	8.91	8.93	8.96	8.97	9.00	9.01	9.01	9.03	9.05	9.08	9.12	9.17	9.22	9.28	9.33	9.27	9.30	9.32
Iroquois Falls DS	-	-	-	5.50	5.48	5.46	5.44	5.42	5.40	5.38	5.36	5.34	5.31	5.30	5.29	5.28	5.28	5.28	5.29	5.30	5.31	5.23	5.22	5.21
Laforest Road DS	-	-	-	13.52	13.53	13.56	13.60	13.64	13.69	13.73	13.77	13.80	13.81	13.86	13.91	13.96	14.02	14.11	14.21	14.31	14.41	14.32	14.37	14.42
Mattawa DS	-	-	-	5.16	5.17	5.19	5.21	5.23	5.26	5.27	5.29	5.31	5.32	5.34	5.36	5.39	5.42	5.46	5.50	5.54	5.58	5.55	5.58	5.60
Monteith DS	-	-	-	3.00	3.01	3.02	3.04	3.05	3.07	3.08	3.10	3.11	3.12	3.13	3.15	3.17	3.19	3.22	3.25	3.28	3.31	3.29	3.31	3.33
Moosonee DS	-	-	-	14.63	14.63	14.65	14.69	14.72	14.77	14.81	14.85	14.87	14.88	14.92	14.96	15.01	15.06	15.15	15.24	15.34	15.43	15.34	15.38	15.43
Shiningtree DS	-	-	-	4.62	4.61	4.60	4.60	4.60	4.60	4.60	4.61	4.60	4.59	4.59	4.59	4.60	4.60	4.62	4.63	4.65	4.67	4.63	4.63	4.63
Smooth Rock Falls DS	-	-	-	1.98	1.98	1.98	1.98	1.98	1.99	1.99	1.99	1.99	1.99	2.00	2.00	2.00	2.01	2.02	2.03	2.04	2.05	2.03	2.04	2.04
Temagami DS 2	-	-	-	1.80	1.81	1.82	1.84	1.85	1.86	1.87	1.89	1.90	1.91	1.92	1.93	1.95	1.96	1.98	2.01	2.03	2.05	2.04	2.06	2.07
Verner DS	-	-	-	6.06	6.06	6.06	6.07	6.08	6.10	6.09	6.10	6.10	6.10	6.10	6.12	6.13	6.16	6.19	6.22	6.26	6.29	6.24	6.25	6.26
Warren DS	-	-	-	7.53	7.52	7.52	7.53	7.53	7.55	7.54	7.54	7.53	7.53	7.53	7.54	7.55	7.58	7.61	7.65	7.68	7.72	7.65	7.66	7.67

Table A.3: North & East of Sudbury Region – Summer Coincident – Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Net Extreme Summer Weather Station Peak Demand Forecast, Coincident to NE of Sudbury Region (MW)																				
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	48.40	43.56	14.80	15.18	15.34	15.50	15.64	15.81	15.93	18.48	18.70	18.83	18.99	19.17	19.37	19.70	19.97	20.26	20.55	20.83	21.63	22.02	22.41
Hearst TS	T4	32.90	29.61	12.50	12.63	12.59	12.56	12.51	12.48	12.43	12.39	12.34	12.28	12.26	12.24	12.24	12.26	12.30	12.36	12.41	12.46	12.25	12.24	12.22
Kapuskasing TS	T5/T6	94.20	84.78	36.17	36.03	35.95	35.92	35.85	35.83	35.70	35.64	35.53	35.41	35.38	35.39	35.43	35.54	35.75	35.98	36.21	36.42	35.76	35.76	35.76
Kirkland Lake TS	T12/T13	47.30	42.57	26.02	25.92	25.87	25.84	25.78	25.75	25.72	25.72	25.66	25.59	25.56	25.54	25.52	25.51	25.56	25.63	25.69	25.76	25.51	25.49	25.47
North Bay TS	T1/T2	61.70	55.53	14.98	13.88	12.78	13.21	13.65	14.09	14.53	14.97	15.39	15.81	16.23	16.67	17.14	17.61	18.09	18.58	19.07	19.56	19.40	19.77	20.14
Ramone TS	T1	18.30	16.47	4.96	4.99	5.01	5.03	5.08	5.13	5.18	5.32	5.36	5.40	5.44	5.48	5.54	5.60	5.65	5.71	5.77	5.83	5.87	5.92	5.98
Timmins TS	T2/T4	104.20	93.78	33.45	33.39	33.38	33.43	33.43	33.48	33.49	33.54	33.52	33.48	33.52	33.59	33.68	33.79	34.01	34.26	34.50	34.74	34.31	34.37	34.44
Dymond TS	T3/T4	54.00	48.60	25.93	25.83	25.77	25.76	25.72	25.71	25.65	25.63	25.56	25.48	26.77	26.78	26.80	26.86	26.98	27.13	27.27	27.41	27.31	27.41	27.52
Trout Lake	T3/T4	186.60	167.94	66.13	64.94	63.85	66.78	67.14	67.58	67.79	68.10	68.46	68.76	69.30	69.83	70.42	71.18	72.08	73.03	73.97	75.31	74.44	75.00	75.55
Calstock DS	-	-	-	3.76	3.75	3.75	3.75	3.75	3.75	3.76	3.78	3.78	3.77	3.77	3.78	3.78	3.79	3.81	3.83	3.85	3.88	3.84	3.85	3.85
CochraneMTS	-	-	-	9.99	9.90	9.83	9.77	9.68	9.62	9.53	9.46	9.39	9.31	9.25	9.21	9.17	9.15	9.15	9.16	9.17	9.17	8.94	8.89	8.84
Cochran West DS	-	-	-	2.58	2.58	2.58	2.58	2.58	2.58	2.58	2.57	2.57	2.57	2.57	2.57	2.58	2.59	2.61	2.63	2.65	2.67	2.63	2.63	2.64
Fauquier DS	-	-	-	1.92	1.93	1.93	1.93	1.94	1.95	1.95	1.95	1.95	1.95	1.96	1.97	1.98	1.99	2.01	2.03	2.05	2.06	2.04	2.05	2.05
Herridge Lake DS	-	-	-	1.65	1.65	1.65	1.65	1.66	1.66	1.66	1.66	1.66	1.66	1.66	1.67	1.68	1.68	1.70	1.71	1.73	1.74	1.72	1.72	1.73
Hoyle DS	-	-	-	4.47	4.47	4.46	4.46	4.46	4.47	4.46	4.47	4.46	4.45	4.46	4.46	4.47	4.49	4.52	4.55	4.57	4.60	4.54	4.55	4.56
Iroquois Falls DS	-	-	-	4.96	4.93	4.90	4.87	4.84	4.81	4.78	4.75	4.71	4.68	4.66	4.64	4.63	4.63	4.63	4.64	4.65	4.66	4.55	4.53	4.51
Laforest Road DS	-	-	-	11.04	11.02	11.02	11.03	11.03	11.05	11.04	11.05	11.04	11.02	11.04	11.06	11.09	11.14	11.21	11.29	11.38	11.46	11.30	11.32	11.34
Mattawa DS	-	-	-	4.37	4.36	4.37	4.38	4.38	4.39	4.39	4.40	4.40	4.40	4.41	4.42	4.43	4.46	4.49	4.53	4.57	4.60	4.54	4.55	4.57
Monteith DS	-	-	-	1.91	1.91	1.91	1.92	1.92	1.93	1.93	1.93	1.94	1.94	1.94	1.95	1.96	1.97	1.99	2.01	2.03	2.05	2.02	2.03	2.04
Moosonee DS	-	-	-	4.97	4.96	4.95	4.96	4.96	4.96	4.96	4.97	4.97	4.96	4.97	4.97	4.98	4.99	5.02	5.05	5.09	5.12	5.06	5.06	5.07
Shiningtree DS	-	-	-	2.43	2.42	2.41	2.41	2.40	2.40	2.39	2.39	2.38	2.37	2.37	2.37	2.37	2.36	2.37	2.38	2.39	2.40	2.36	2.36	2.36
Smooth Rock Falls DS	-	-	-	1.64	1.64	1.63	1.63	1.63	1.63	1.63	1.63	1.62	1.62	1.62	1.62	1.62	1.62	1.63	1.64	1.65	1.66	1.63	1.63	1.63
Temagami DS 2	-	-	-	0.98	0.98	0.98	0.99	0.99	1.00	1.00	1.01	1.01	1.01	1.02	1.02	1.03	1.04	1.05	1.06	1.07	1.08	1.07	1.08	1.08
Verner DS	-	-	-	4.04	4.03	4.02	4.02	4.01	4.01	3.99	3.98	3.97	3.96	3.96	3.96	3.97	3.98	4.01	4.03	4.06	4.08	4.01	4.01	4.01
Warren DS	-	-	-	5.02	5.00	4.99	4.98	4.97	4.97	4.94	4.93	4.91	4.89	4.89	4.89	4.89	4.90	4.93	4.96	4.98	5.01	4.92	4.91	4.91

Table A.4: North & East of Sudbury Region – Summer non-Coincident – Net Load Forecast

Transformer Station	DESN ID	LTR (MVA)	LTR (MW)	Net Extreme Summer Weather Station Peak Demand Forecast, Coincident to NE of Sudbury Region (MW)																				
				2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040	2041	2042	2043
Crystal Falls TS	T5/T6	48.40	43.56	23.02	23.61	23.86	24.10	24.33	24.59	24.78	28.74	29.08	29.28	29.53	29.82	30.13	30.63	31.06	31.52	31.96	32.40	33.64	34.24	34.85
Hearst TS	T4	32.90	29.61	14.79	14.95	14.89	14.86	14.80	14.77	14.70	14.66	14.60	14.53	14.50	14.49	14.48	14.50	14.55	14.62	14.68	14.74	14.50	14.48	14.46
Kapuskasing TS	T5/T6	94.20	84.78	64.77	64.52	64.36	64.32	64.18	64.15	63.93	63.82	63.61	63.40	63.35	63.37	63.45	63.64	64.01	64.43	64.84	65.21	64.03	64.03	64.02
Kirkland Lake TS	T12/T13	47.30	42.57	27.37	27.27	27.21	27.18	27.11	27.08	27.05	27.05	26.99	26.91	26.88	26.86	26.85	26.83	26.89	26.96	27.03	27.09	26.83	26.81	26.79
North Bay TS	T1/T2	61.70	55.53	18.22	16.87	15.55	16.06	16.60	17.14	17.67	18.20	18.72	19.22	19.74	20.28	20.84	21.42	22.00	22.60	23.19	23.78	23.59	24.04	24.49
Ramone TS	T1	18.30	16.47	7.20	7.24	7.27	7.31	7.38	7.45	7.51	7.72	7.78	7.83	7.89	7.96	8.04	8.12	8.21	8.29	8.38	8.46	8.52	8.60	8.68
Timmins TS	T2/T4	104.20	93.78	36.64	36.57	36.56	36.61	36.61	36.67	36.68	36.74	36.72	36.67	36.72	36.79	36.89	37.01	37.25	37.52	37.79	38.05	37.58	37.65	37.72
Dymond TS	T3/T4	54.00	48.60	30.08	29.97	29.90	29.89	29.83	29.83	29.76	29.74	29.66	29.56	31.06	31.06	31.09	31.16	31.30	31.47	31.64	31.79	31.68	31.80	31.93
Trout Lake	T3/T4	186.60	167.94	77.61	76.21	74.93	78.37	78.80	79.31	79.55	79.92	80.35	80.69	81.33	81.95	82.65	83.54	84.59	85.71	86.81	88.38	87.36	88.01	88.67
Calstock DS	-	-	-	6.96	6.94	6.93	6.94	6.93	6.94	6.96	6.99	6.99	6.98	6.98	6.99	7.00	7.01	7.05	7.09	7.13	7.18	7.11	7.12	7.13
CochraneMTS	-	-	-	12.44	12.33	12.24	12.16	12.06	11.98	11.87	11.79	11.69	11.59	11.53	11.47	11.42	11.40	11.40	11.41	11.42	11.42	11.14	11.08	11.01
Cochran West DS	-	-	-	2.86	2.86	2.86	2.86	2.86	2.86	2.86	2.85	2.85	2.84	2.85	2.85	2.86	2.87	2.89	2.92	2.94	2.96	2.91	2.92	2.92
Fauquier DS	-	-	-	2.57	2.57	2.57	2.58	2.59	2.59	2.60	2.60	2.60	2.61	2.61	2.62	2.64	2.65	2.68	2.70	2.73	2.75	2.72	2.73	2.74
Herridge Lake DS	-	-	-	2.24	2.24	2.24	2.25	2.25	2.26	2.26	2.26	2.26	2.26	2.26	2.27	2.28	2.29	2.31	2.33	2.35	2.36	2.33	2.34	2.35
Hoyle DS	-	-	-	6.36	6.35	6.34	6.35	6.35	6.35	6.35	6.35	6.34	6.33	6.34	6.35	6.36	6.39	6.42	6.47	6.51	6.54	6.46	6.47	6.48
Iroquois Falls DS	-	-	-	5.47	5.43	5.40	5.37	5.34	5.31	5.27	5.23	5.20	5.16	5.14	5.12	5.11	5.10	5.11	5.12	5.13	5.14	5.02	5.00	4.98
Laforest Road DS	-	-	-	13.27	13.25	13.24	13.26	13.26	13.28	13.27	13.28	13.27	13.25	13.26	13.29	13.33	13.38	13.47	13.57	13.67	13.77	13.58	13.60	13.63
Mattawa DS	-	-	-	5.18	5.18	5.18	5.19	5.20	5.21	5.21	5.22	5.22	5.22	5.23	5.24	5.26	5.29	5.33	5.37	5.42	5.46	5.39	5.40	5.42
Monteith DS	-	-	-	2.24	2.24	2.24	2.25	2.26	2.26	2.26	2.27	2.27	2.27	2.28	2.29	2.30	2.31	2.34	2.36	2.38	2.40	2.37	2.38	2.39
Moosonee DS	-	-	-	8.69	8.67	8.66	8.67	8.66	8.67	8.68	8.69	8.69	8.67	8.68	8.69	8.71	8.73	8.78	8.83	8.89	8.94	8.84	8.85	8.86
Shiningtree DS	-	-	-	3.02	3.00	2.99	2.99	2.98	2.97	2.97	2.97	2.96	2.95	2.94	2.94	2.94	2.93	2.94	2.95	2.96	2.98	2.93	2.93	2.93
Smooth Rock Falls DS	-	-	-	1.93	1.92	1.92	1.92	1.91	1.91	1.91	1.91	1.90	1.90	1.90	1.90	1.90	1.90	1.91	1.93	1.94	1.95	1.92	1.92	1.92
Temagami DS 2	-	-	-	2.65	2.65	2.66	2.68	2.69	2.70	2.71	2.72	2.73	2.74	2.75	2.77	2.79	2.81	2.84	2.87	2.90	2.93	2.90	2.92	2.93
Verner DS	-	-	-	4.56	4.55	4.54	4.54	4.53	4.53	4.52	4.51	4.49	4.48	4.48	4.48	4.49	4.50	4.53	4.56	4.58	4.61	4.53	4.53	4.53
Warren DS	-	-	-	5.57	5.55	5.53	5.53	5.51	5.51	5.48	5.47	5.45	5.43	5.42	5.42	5.42	5.44	5.47	5.50	5.53	5.55	5.46	5.45	5.45

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Appendix B:

Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations	Voltages (kV)	Supply Circuits
1.	Ansonville TS	230/115	A9K A94N A5H A4H P91G A93I A8K
2.	Crystal Falls TS	230/44	H23S H24S
3.	Dymond TS	115/44	D4Z D3K D2L W71D
4.	Hearst TS	115/27.6	F1E
5.	Hunta SS	115	H7T A5H A4H H9K H6T D2H D3H
6.	Kapuskasing TS	230/115/28	H9K L21S K38S F1E
7.	Kirkland Lake TS	115/44	A8K A9K D3K K2 K4
8.	Little Long SS	230/44	L20D L21S
9.	Moosonee SS	115	T7M T8M M3K M9K
10.	North Bay TS	230/44	L5H
11.	Otter Rapids SS	115	T7M T8M R21D D6T
12.	Otto Holden TS	230/115/14	L5H D5H H4Z H23S H24S
13.	Pinard TS	500/230/115	L20D H22D R21D D3H D501P D4 D6T D23G D2H
14.	Porcupine TS	500/230/115	P91G P15T P7G D501P P13T P502X
15.	Ramore TS	115/27.6	A9K
16.	Spruce Falls TS	230/115/14	F1E K38S
17.	Timmins TS	115/27.6	H7T T2R H6T P15T T61S P13T
18.	Trout Lake TS	230/44	H24S W71D
19.	Widdifield SS	230	H23S H24S W71D

Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	A4H/A5H	Ansonville TS	Hunta SS	115
2.	A8K/A9K	Ansonville TS	Kirkland Lake TS	115
3.	D2H/D3H	Pinard TS	Hunta SS	115
4.	H6T/H7T	Hunta SS	Timmins TS	115
5.	P13T/P15T	Porcupine TS	Timmins TS	115
6.	T7M/T8M	Otter Rapids SS	Moosenee SS	115
7.	D2L	Dymond TS	Crystal Falls TS	115
8.	H9K	Hunta SS	Kapuskasing TS	115
9.	K2	Kirkland Lake TS	Radial	115
10.	K4	Kirkland Lake TS	Radial	115
11.	L1S	Martindale TS	Crystal Falls TS	115
12.	L5H	Crystal Falls TS	Otto Holden TS	115
13.	D3K	Dymond TS	Kirkland Lake TS	115
14.	P7G	Porcupine TS	Radial	115
15.	T61S	Timmins TS	Radial	115
16.	F1E	Kapuskasing TS	Hearst TS	115
17.	T2R	Timmins TS	Radial	115
18.	D23G	Pinard TS	Radial	230
19.	H22D	Pinard TS	Radial	230

20.	H23S/H24S	Martindale TS	Otto Holden TS	230
21.	K38S	Kapuskasing TS	Spruce Falls TS	230
22.	L20D	Pinard TS	Little Long SS	230
23.	L21S	Kapuskasing TS	Little Long SS	230
24.	P91G	Porcupine TS	Ansonville TS	230
25.	R21D	Otter Rapids SS	Radial	230
26.	W71D	Dymond TS	Widdfield SS	230
27.	P502X	Porcupine TS	Hanmer TS	500
28.	D501P	Porcupine TS	Pinard TS	500

Appendix C: Voltage Performance Analysis at Dymond TS

To address the on-going voltage issue due to operation of SC11& SC12 Capacitor banks at Dymond TS under N-1-1 contingency, Hydro One can de-rate the capacitor bank between 14-16MX. The capacitor banks can only be physically de-rated in the steps of 3MX.

Following table shows a PSSE simulation result with both capacitors de-rated to 15MX. (*Hydro One 2022 Winter Base case used far simulation purpose).*

Bus	Contingency														
	N-0					D3K O/S					D3K O/S +W71D				
		24+24 MX Caps		15+15 MX Caps			24+24 MX Caps		15+15 MX Caps			24+24 MX Caps		15+15 MX Caps	
	No Cap	ON	% Change	ON	% Change	No Cap	ON	% Change	ON	% Change	No Cap	ON	% Change	ON	% Change
Dymond TS 220	243.89	246.62	1.12	245.59	0.69	244.44	248.25	1.56	246.80	0.96					
Dymond TS 115	123.49	125.67	1.77	124.84	1.10	124.05	127.08	2.44	125.92	1.50	117.51	131.96	12.30	125.76	7.03
Dymond TS 44	46.35	47.11	1.63	46.82	1.02	46.55	47.59	2.25	47.19	1.39	44.28	49.37	11.50	47.15	6.47
Temagami 115	123.41	124.93	1.22	124.35	0.76	123.98	126.06	1.68	125.27	1.04	119.78	129.21	7.88	125.19	4.52

Capacitor bank switching under the studied scenario is infrequent due to the N-1-1 condition and voltage change limits shall take this into consideration. Sizing the capacitor banks between 14-16MX is shown to reduce the voltage change to reasonable limits based on the in frequent nature of the occurrence. This reduction allows for reactive support at Dymond TS to remain at a level that can still help with normal operations during non-contingency scenarios or system changes such as load growth. Simulation results will continue to be studied to correctly size the capacitor banks.

Appendix D: List of LDC's

Sr. No.	Local Distributor Company	Connection Type (TX/DX)
1.	Hydro One Distribution	TX/DX
2.	North Bay Hydro	DX
3.	Northern Ontario Wires Inc.	TX/DX
4.	Hearst Power Distribution Co.	DX
5.	Greater Sudbury Hydro Inc.	DX

Appendix E: List of Municipalities in the region

Sr. no.	Name of Municipality
1	Town of Hearst
2	Town of Kapuskasing
3	Town of Smooth Rock Falls
4	Town of Cochrane
5	Town of Foleyet
6	Town of Iroquois Falls
7	Town of Kirkland Lake
8	Town of Englehart.
9	Township of Black River
10	Township of Matheson
11	Township of East Ferris
12	City of North Bay
13	City of Temiskaming Shores
14	City of Timmins
15	Municipality of West Nipissing

Appendix F: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CEP	Community Energy Plan
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
MEP	Municipal Energy Plan
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
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 D

2024 Asset Condition Assessment

Northern Ontario Wires Inc.

Asset Condition Assessment Report 2024

Client Document No.: 0001

August 21, 2024

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REVISION HISTORY

Revision	Document Status – Revision Description	Date
IFR	Issued For Review	August 21, 2024

Executive Summary

This report relays the findings of an Asset Condition Assessment ("ACA") of the major electrical assets of Northern Ontario Wires ("NOW"). NOW engaged BBA to conduct as ACA based on the latest demographic, testing and inspection data.

This Asset Condition Assessment is based on data compiled up to August 2024 and covers the following assets classes:

Distribution Assets
1. Wood Poles
2. Pole-mount Transformers
3. Pad-mount Transformers
4. Primary Overhead ("OH") Conductors
5. Primary Underground ("UG") Cables
6. Overhead Switches

Station Assets
1. Power Transformers and Tap Changers
2. Station Switchgears

For all asset classes that underwent assessment, BBA used a consistent scale of asset health, containing five categories – from Very Good to Very Poor. The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, given as a score from 0 to 100. The HI formulations for individual asset classes represent weighted averages of numerical scores for individual HI subcomponents, known as condition parameters, scored on a scale from 0 to 100. The numerical score ranges, condition categories, and typical characteristics of an asset are described in Table 0-1.

Table 0-1: Definition of HI Scores

Score (%)	Condition Category	Description
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components
[70-85)	Good	Significant deterioration of select components to be managed through normal maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components
[30-50)	Poor	Widespread serious deterioration across multiple components
[0-30)	Very Poor	Extensive serious deterioration – an asset has reached its end-of-life

The relative contribution of various condition parameter scores on the aggregate HI results is a function of weighting – assigned by an engineer to each HI subcomponent prior to commencing calculations. Using this methodology, BBA calculated HI results for NOW's wood poles, pole-mounted transformers, power transformers, tap changers, and station switchgears. For the remaining asset classes BBA was not provided enough produce a valid HI and age-based results were calculated instead. NOW's Health Index ("HI") results are summarized in Figure 0-1 and Table 0-2. Table 0-3 presents the age each asset class compared to the Typical Useful Life ("TUL").

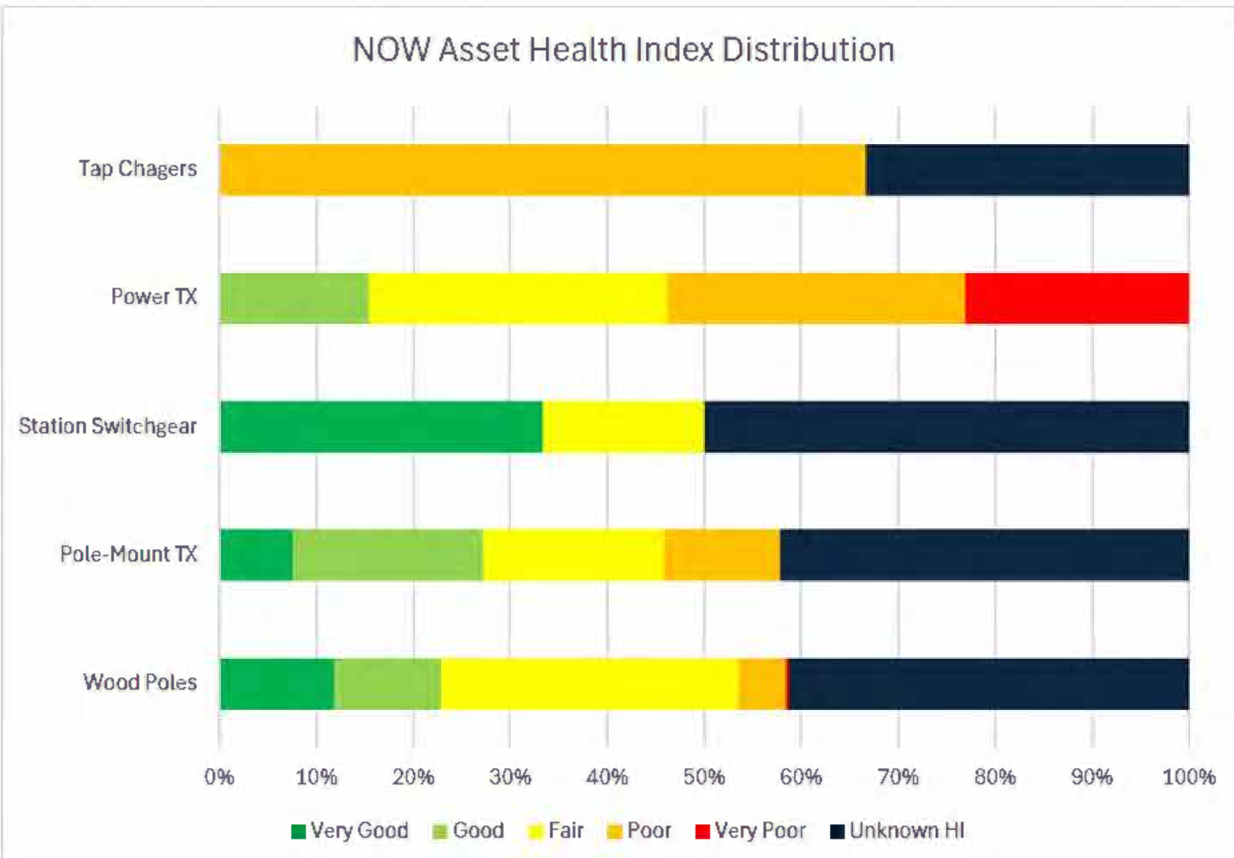

Figure 0-1: NOW Asset HI Distribution

Table 0-2: NOW Asset HI Results

Asset Category	Population	HI Distribution						DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	
Distribution Assets								
Wood Poles	2998	354	331	920	146	9	1238	75%
Pole-Mount Transformers	581	44	114	108	70	0	245	71%
Station Assets								
Power Transformers	13	0	2	4	4	3	0	99%
Tap Changers	3	0	0	0	2	0	1	85%
Station Switchgears	6	2	0	1	0	0	3	58%

Table 0-3: NOW Asset Age Results

Asset Category	Population	Age Demographics by TUL						TUL
		< 33%	33-66%	67-100%	101-133%	>133%	Unknown	
Distribution Assets								
Wood Poles	2998	513	604	852	611	278	140	45
Pole-Mount Transformers	581	85	57	84	92	18	245	40
Pad-Mount Transformers	26	0	11	15	0	0	0	40
OH Conductors	1226	0	650	523	41	0	12	60
UG Cables	25	0	0	0	16	9	0	25
OH Switches	143	0	78	55	6	0	4	45
Station Assets								
Power Transformers	13	0	0	0	4	8	1	45
Tap Changers	3	0	0	0	0	2	1	30
Station Switchgears	6	0	0	0	1	3	2	40

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Acronym	Definition
ACA	Asset Condition Assessment
AM	Asset Management
DAI	Data Availability Index
DG	Dissolved Gas Analysis
HI	Health Index
NOW	Northern Ontario Wires
OH	Overhead
OQ	Oil Quality
TUL	Typical Useful Life

1. Introduction

This report summarizes the results of an Asset Condition Assessment (“ACA”) study carried out by BBA on behalf of Northern Ontario Wires (“NOW”). NOW engaged BBA to update the ACA based on the demographic and inspection data provided by NOW in June through August 2024.

The Asset Condition Assessment methodology was applied to different categories of fixed assets that are employed in NOW’s distribution system. Adoption of the ACA methodology would require periodic asset inspections and recording of their condition to identify those most at risk, requiring focused investments into risk mitigation. Additionally, computing the HI (“Health Index”) for distribution assets requires identifying End of Life (“EOL”) criteria for various components associated with each asset type. Each criterion represents a factor that is influential in determining the component’s current condition relative to conditions reflective of potential failure. These components and tests shown in the tables are weighted based on their importance in determining a given asset’s EOL.

The assets classes covered in the report include the following:

Distribution Assets

1. Wood Poles
2. Pole-mount Transformers
3. Pad-mount Transformers
4. Primary Overhead (“OH”) Conductors
5. Primary Underground (“UG”) Cables
6. Overhead Switches

Station Assets

1. Power Transformers and Tap Changers
2. Station Switchgears

2. Asset Health Index Calculation Methodology

ACA is the process of determining an HI, which is a quantitative expression of an asset's current condition. A brand-new asset should have an HI of 100% and an asset in very poor health should have an HI below 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 2-1 presents the HI ranges and the corresponding asset condition.

Table 2-1: Definition of HI Scores

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of ageing 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 planning process to replace or rehabilitate, considering 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 the assessment

2.1. Condition Parameters

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific to each asset class. A condition parameter can be comprised of many sub-condition parameters. For example, the oil quality ("OQ") condition parameter of an asset belonging to the station power transformer asset class includes multiple sub-condition parameters such as acid number, interfacial tension, dielectric strength, and water content.

To determine the overall 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 particular asset type. 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 2-1 provides an example of an HI formulation ("HIF") table.

Figure 2-1: HI Formulation Components

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 Indicator of 4 represents the best grade, whereas a Condition Indicator of 0 represents the worst grade. In some cases where there are multiple sub-condition parameters contributing to a single condition parameter, the lowest sub-Condition Indicator is taken as the overall Condition Indicator for that parameter. This prevents deficiencies in an asset's health from being covered up by an averaging process during the HI calculation.

The conversion from alphabetic ranking to numerical grade and a brief character description of the grade is provided in Table 2-2.

Table 2-2: Sample Letter-Numerical Conversion Chart

Letter/Number Grade	Grade Description
A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

2.2. Final Asset Health Index Formulation

The final HI, which is a function of the Condition Indicators and weights, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} W_i * CI_i}{CI_{max.}}\right)$$

where:

- i corresponds to the condition parameter number within the HI formulation;
- CI_i represents the Condition Indicator as determined from the testing or field-inspection procedure that is associated with condition parameter i;
- Wi represents the relative importance of condition parameter i within the HI based on the impact of the parameter on the asset's overall failure probability;
- CI_{max} represents the highest numerical grade that can be assigned to the asset and is being used to normalize the final HI score between 0% and 100%; and
- HI represents the asset health index as a percentage.

2.3. Asset Health Index Results

An asset's HI is given as a percentage; the HI is calculated only if sufficient condition parameter data for a given asset is available. The subset of the total population with sufficient data parameters is called the sample size. HI results can be analyzed on a per-asset, per-asset-class, or per-system basis depending on the granularity required in the analysis.

2.4. Data Availability Index

The DAI is a measure of the availability of condition parameter data for a specific asset, as they pertain to the construction of the HI score. The DAI is determined by comparing the sum of the weights of the condition parameters available to the total weight of the condition parameters used to construct the HI for an asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} W_i * \alpha_i}{\sum_{i=1} W_i}\right)$$

where:

- *i* iterates through the condition parameters within the HI formulation;
- W_i is the weight assigned to condition parameter *i*;
- α_i represents the data availability coefficient, which is equal to 1 if data is available, and equal to 0 when data is unavailable; and

- *DAI* represents the Data Availability Index as a percentage.

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 higher DAI will correlate to HI scores with a higher degree of confidence. For an individual asset, the HI was not calculated if the DAI fell below 70%. The average DAI for each asset class is summarized in *Table 2-3* below. Overhead switches, pad-mount transformers, overhead conductors and underground cables were evaluated based on age only, therefore the DAI for these asset classes is not relevant.

Table 2-3: Average DAI by Asset Class

Asset Class	Average DAI
Wood Poles	75%
Pole-mounted Transformers	71%
Substation Switchgears	58%
Substation Power Transformers	99%
Substation Power Transformer Tap Changers	85%

2.5. Data Gaps

The HIFs calculated in this study are based only on available data provided by NOW. In almost all instances, additional condition parameters or tests exist that can be performed on an asset to further ascertain its state of degradation. In certain cases, condition parameters may be available for one or several assets in a class, but unavailable for others in the same class. This scenario represents a data gap, wherein the planner must determine whether the number of assets for which a particular parameter is available is sufficient to include it in the calculation of the overall HI.

An asset with all condition parameter data available will have a DAI value of 100%, independent of that 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. The DAI threshold is taken to be 70% throughout this study.

2.6. Use of Age as a Condition Parameter

There is a degree of debate within the electrical utility industry regarding the appropriateness of including age as a condition parameter for calculating asset Health Indices. At the core of the argument against the use of age in assessing asset condition is the notion that age implies a linear degradation path for an asset that does not always match the experience in the field.

While some assets lose their structural integrity faster than would be expected with 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 time than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, BBA attempts to limit the instances where it relies on age as a parameter explicitly incorporated into the calculation of asset HI. In some cases, however, the limited number of condition parameters available for the 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 the condition of complex equipment (e.g., power transformers) – which contain 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.

In the context of the current study, the availability of data on condition parameters varied significantly across asset classes. Where BBA deemed the number of available condition parameters as insufficient to calculate a reliable HI for a particular asset class, and especially where the available information amounted to factors that do not represent the most significant degradation factors for a particular type of equipment, we included age as one of the condition parameters where data was available.

3. Asset Condition Assessment Results

This section presents the current HIF for each asset class, the calculated HI scores, Typical Useful Life ("TUL") results, and reviews the data available to perform the study. Figure 3-1 and Table 3-1 summarize the HI Results for each asset class in the ACA study. Table 3-2 shows the age results of each asset class.

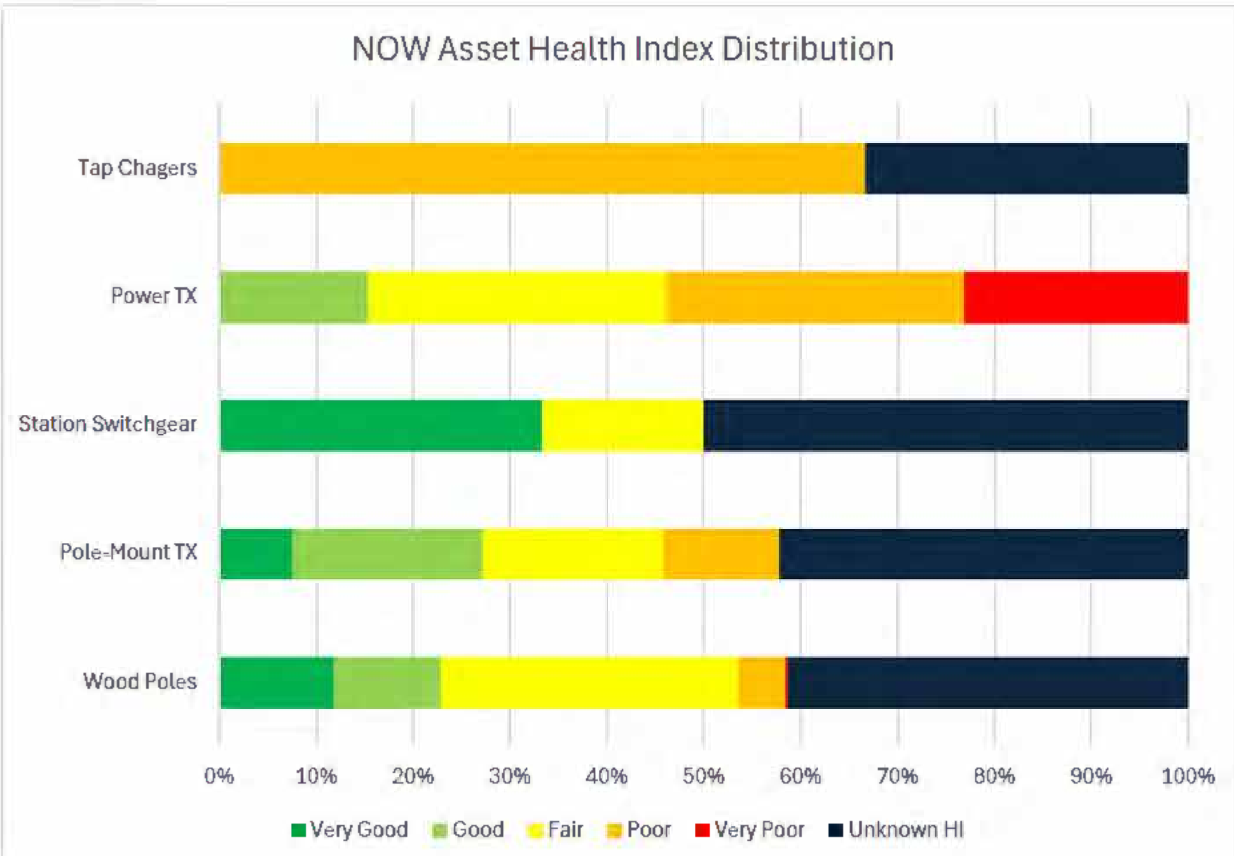


Figure 3-1: NOW Asset HI Distribution

Table 3-1: NOW Asset HI Results

Asset Category	Population	HI Distribution						DAI
		Very Good	Good	Fair	Poor	Very Poor	Unknown HI	
Distribution Assets								
Wood Poles	2998	354	331	920	146	9	1238	75%
Pole-Mount Transformers	581	44	114	108	70	0	245	71%
Station Assets								
Power Transformers	13	0	2	4	4	3	0	99%
Tap Changers	3	0	0	0	2	0	1	85%
Station Switchgears	6	2	0	1	0	0	3	58%

Table 3-2: NOW Asset Age Results

Asset Category	Population	Age Demographics by TUL						TUL
		< 33%	33-66%	67-100%	101-133%	>133%	Unknown	
Distribution Assets								
Wood Poles	2998	513	604	852	611	278	140	45
Pole-Mount Transformers	581	85	57	84	92	18	245	40
Pad-Mount Transformers	26	0	11	15	0	0	0	40
OH Conductors	1226	0	650	523	41	0	12	60
UG Cables	25	0	0	0	16	9	0	25
OH Switches	143	0	78	55	6	0	4	45
Station Assets								
Power Transformers	13	0	0	0	4	8	1	45
Tap Changers	3	0	0	0	0	2	1	30
Station Switchgears	6	0	0	0	1	3	2	40

3.1. Health Indices

3.1.1. Wood Poles

Condition Assessment Methodology

Wood poles are the most common asset owned by an electrical utility and are an integral part of the distribution system. Poles are the support structure for OH distribution lines as well as assets such as OH transformers, switches, and reclosers.

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation processes for wood poles involve biological and environmental mechanisms such as fungal decay, wildlife damage, and effects of weather which can impact the mechanical strength of the pole. Loss in the strength of the pole can present additional safety and environmental risks to the public and the utility. In the short term (one to three years), the most informative end-of-life criterion is the calculation of remaining strength through pole testing. However, since pole strength tends to fall off quickly as a pole starts to degrade, the preferred predictor over the medium to long term (three to ten years) is age. Generally, poles that are newer than ten or twenty years in service are not tested at all other than by way of visual inspections. A pole that is not yet showing effects of age but exhibits other defects such as large cracks or rot or is out of plumb may also be targeted for replacement.

The HI for wood poles is calculated by considering a combination of service age, and visual inspection results. Table 3-3 summarizes the methodology to combine these criteria into an overall HI for wood poles. Appendix A provides grading tables for each condition parameter.

Table 3-3: Wood Poles HI Algorithm

Condition Parameter	Weight	Ratings	Numerical Score	Max Score
Service Age	10	A,B,C,D,E	4,3,2,1,0	40
Guy Wire Condition	4	A,C,E	4,3,2,1,0	16
Cross Arm Condition	3	A,E	4,3,2,1,0	12
Surface Wear and Scaling	2	A,B,C,D,E	4,3,2,1,0	8
Bent, Cracked, Rotten	2	A,B,C,D,E	4,3,2,1,0	8
Wood Pecker, Insect Damage, Bird Nests	1	A,B,C,D,E	4,3,2,1,0	4
Burns, Lightning Damage	1	A,B,C,D,E	4,3,2,1,0	4
			Total Score	**92**

Data Collection and Assumptions

NOW's inspection records, and pole asset registry were the primary sources of information used to complete the wood poles condition assessment. Pole visual inspections were recorded between April to July 2024. The average DAI for wood poles was 75%

Demographics

NOW owns 2,998 wood poles across its three service areas. The service age is known for 95% of NOW's wood poles. Table 3-4 presents the wood poles' age demographics by service area. Figure 3-2 shows the age distribution of wood poles.

Figure 3-2 presents the age distribution, and Figure 3-3 shows the age demographics by TUL. The TUL for wood poles is 45 years. The age demographics by TUL reveal that 9% of the assets have exceeded 133% of their TUL, indicating they are well beyond their expected service life. Additionally, 20% of the poles are between 101% and 133% of their TUL, slightly past their anticipated lifespan. The remaining poles fall into other TUL categories, illustrating the varying stages of their service life.

Table 3-4: Age of Wood Poles by Service Area

Age	Number of Wood Poles by Service Area				
	Cochrane	Iroquois Falls	Kapuskasing	Unknown Area	Total
0-15 years	204	139	166	4	513
16-30 years	138	110	356	0	604
31-45 years	392	276	183	1	852
46-60 years	77	332	202	0	611
61+ years	50	7	221	0	278
Unknown	5	117	17	1	140
Total	**866**	**981**	**1145**	**6**	**2998**

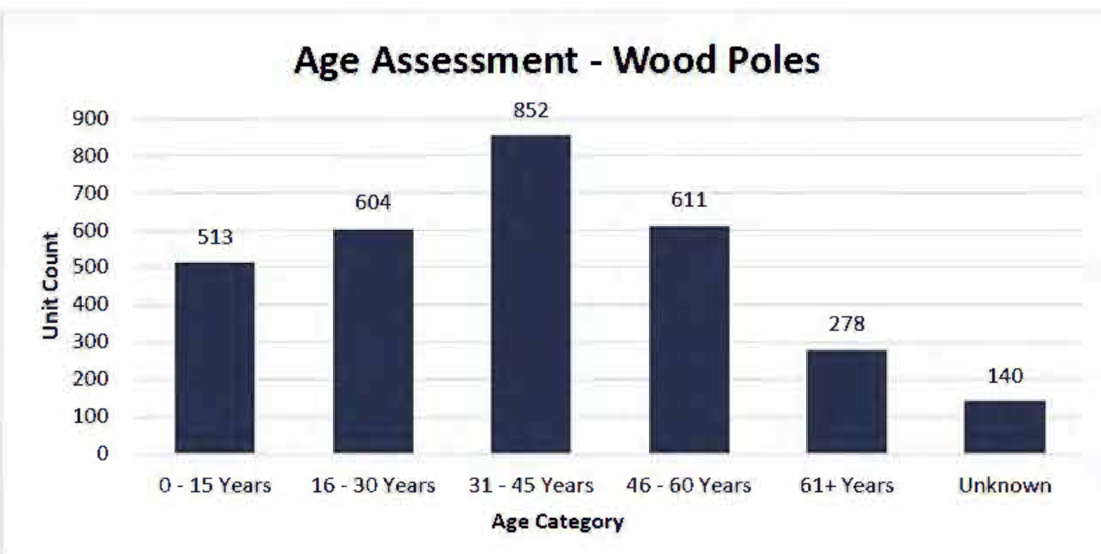


Figure 3-2: Wood Pole Age Demographics

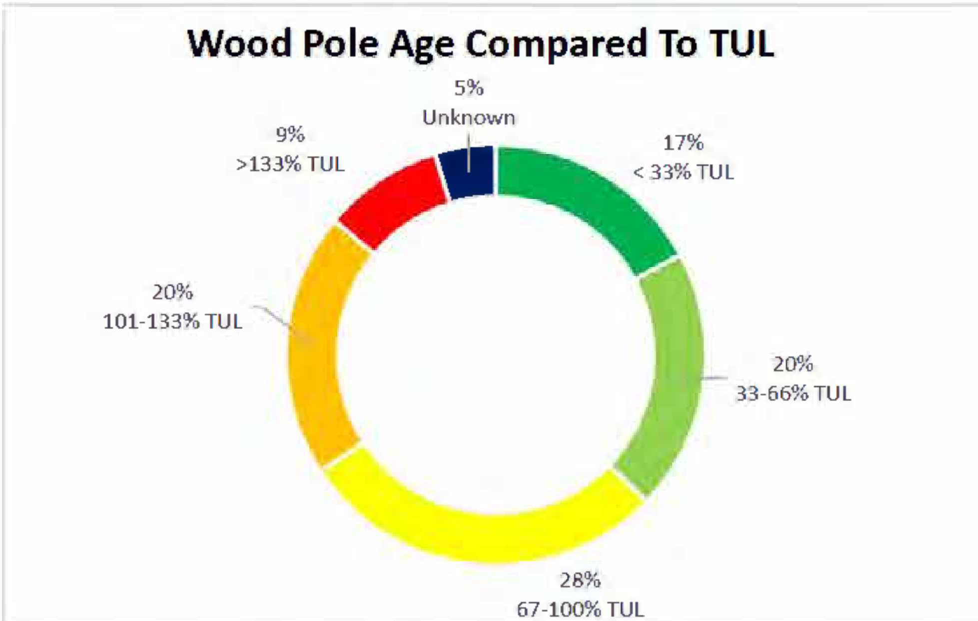


Figure 3-3: Age Summary of Wood Poles by TUL

Results

HI results were calculated for 2,998 wood poles and are summarized in Table 3-5 and Figure 3-4 below. There are 907 wood poles whose condition was identified at Fair. Additionally, 41% of the wood poles have an unknown HI due to insufficient data. The age results for wood poles are shown in Figure 3-5.

Table 3-5: Wood Pole HI Results by Service Area

Condition	Number of Wood Poles by Service Area				
	Cochrane	Iroquois Falls	Kapuskasing	Unknown Area	Total
Very Good	182	108	61	3	354
Good	148	139	44	0	331
Fair	393	438	75	1	907
Poor	44	56	59	0	159
Very Poor	5	0	4	0	9
Unknown HI	94	240	902	2	1238
Total	866	981	1145	6	2998

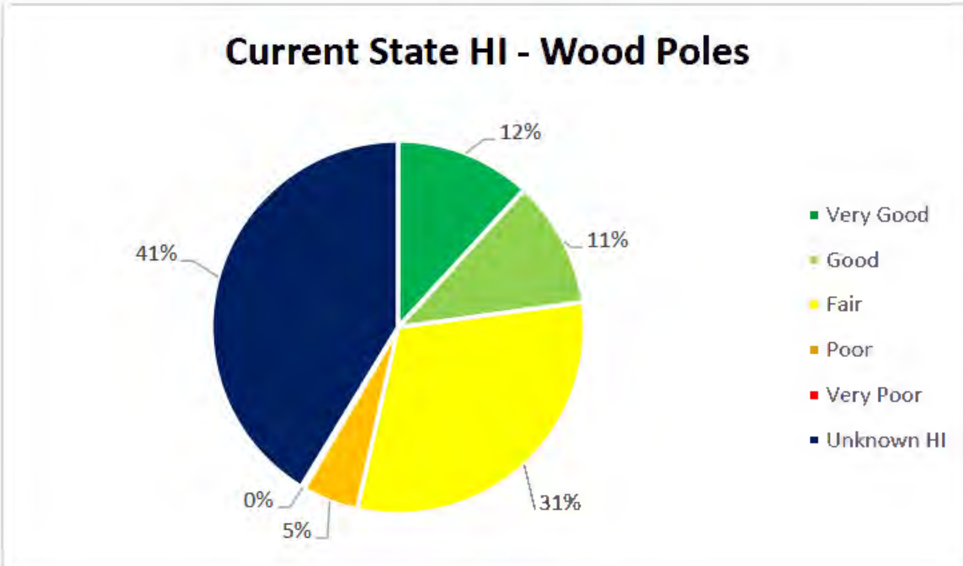


Figure 3-4: HI Results for Wood Poles

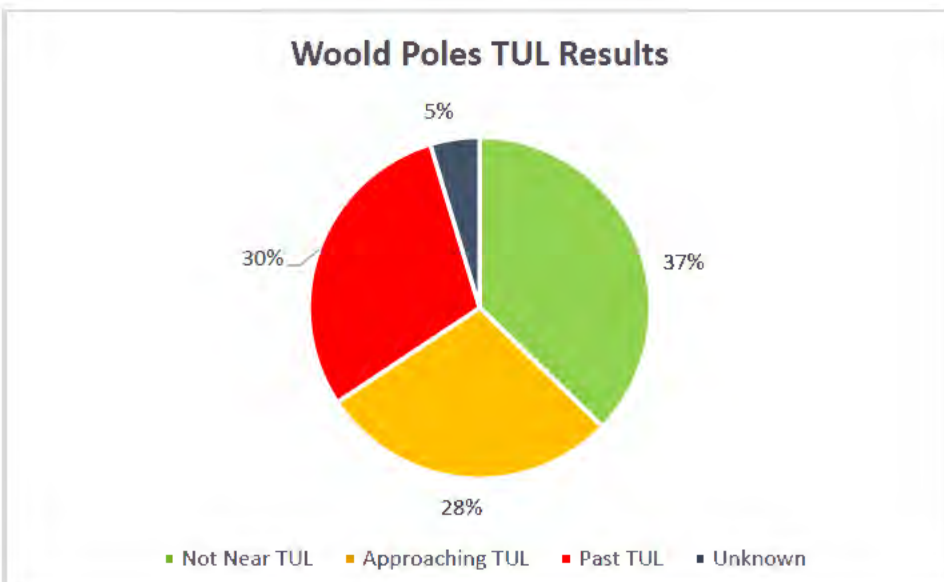


Figure 3-5: TUL Results for Wood Poles

3.1.2. Pole-Mounted Transformers

Condition Assessment Methodology

Pole-mount distribution transformers represent a significant asset class within the distribution system. Although the number of units is relatively limited compared to other asset categories, each transformer plays a critical role in delivering reliable service. NOW owns a total of 581 pole-mounted transformers across its three service areas, each with a modest replacement value.

Pole-mount distribution transformers are typically managed as a run-to-failure asset class, requiring minimal maintenance beyond routine visual inspections. Transformers may be replaced in planned projects based on identifiable degradation, pole line rebuilds, road relocations, or upgrade projects in response to customer load growth.

Pole-mount distribution transformers typically reach their end-of-life due to physical tank deterioration (e.g., corrosion), which in extreme cases can lead to an instance of leaking oil. Where corrosion is detected, a transformer may be cycled back to the shop and re-painted with gaskets being replaced. Other modes of failure include overheated connections caused by loosened connectors, which are identified during visual inspections and addressed by tightening to reduce the risk of failure.

Most commonly, utilities replace Pole-mount distribution transformers as part of OH rebuild projects. Occasionally, a transformer will become overloaded due to changes in customer usage which can be detected by summing loads monitored with automated meter infrastructure and can lead to internal failures if not rectified. The HI values for pole-mount distribution transformers are calculated by considering a combination of service age, and visual inspection results. Table 3-6 shows the HI algorithm for pole-mount distribution transformers. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 3-6: Pole-Mount Distribution Transformer HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	10	A,B,C,D,E	4,3,2,1,0	40
Paint Corrosion	1	A,B,C,D,E	4,3,2,1,0	4
Oil Leaks	4	A,E	4,0	16
Grounding System	1	A,B,C,D,E	4,3,2,1,0	4
Heating or Discolouration	4	A,B,C,D,E	4,3,2,1,0	16
Connections Condition	2	A,B,C,D,E	4,3,2,1,0	8
			Total Score	**88**

Data Collection and Assumptions

The service age was available for 58% of the pole-mount transformers. Visual inspection records between June to July 2024 were used to determine the asset's overall condition. Visual inspection results were available for 86% of the pole-mounted transformers. The average DAI for pole-mount transformers was 71%.

Demographics

NOW owns 581 pole-mount distribution transformers across its three service territories. The service age is known for near 58% of NOW's pole-mount transformers. Table 3-7 presents the age demographics of pole-mount transformers by service area.

Table 3-7: Pole-mount Transformer Age Demographics by Service Area

Age	Number of Pole-Mounted Transformers				
	Cochrane	Iroquois Falls	Kapuskasing	Unknown	Total
0-13 years	45	11	29	0	85
14-26 years	23	10	24	0	57
27-40 years	41	8	35	0	84
41-53 years	54	16	22	0	92
>54 years	4	6	8	0	18
Unknown	67	106	70	2	245
Total	234	157	188	2	581

Figure 3-6 presents the age distribution of the pole-mount transformers. Most known pole-mounted transformers are between 11-30 years old. Figure 3-7 provides the age demographics for pole-mounted transformers by TUL. The TUL for pole-mount transformers is 40 years. The data indicates that 42% of the pole-mounted transformers have an unknown age. Among those with known ages, 15% are within 33% of their TUL, 10% are between 33-66% of their TUL, 14% are between 67-100% of their TUL, 16% are between 101-133% of their TUL, and 3% have exceeded 133% of their TUL, indicating they are well beyond their expected service life.

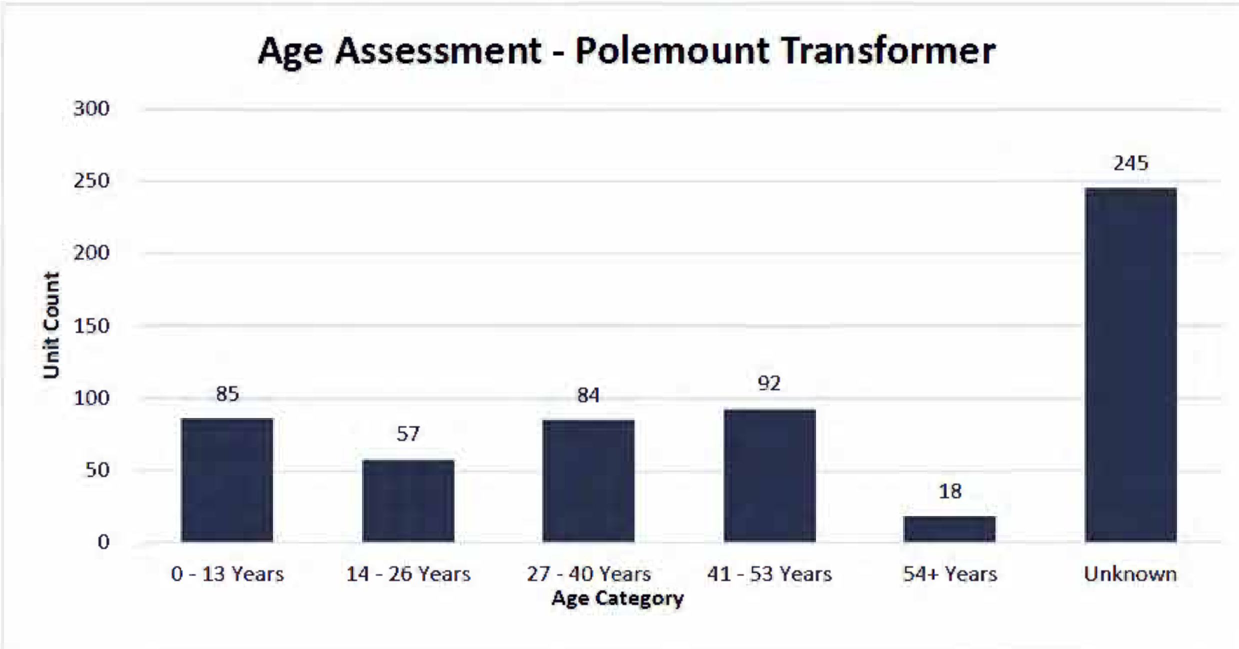


Figure 3-6: Consolidated Age Demographics of Pole-mount Transformers

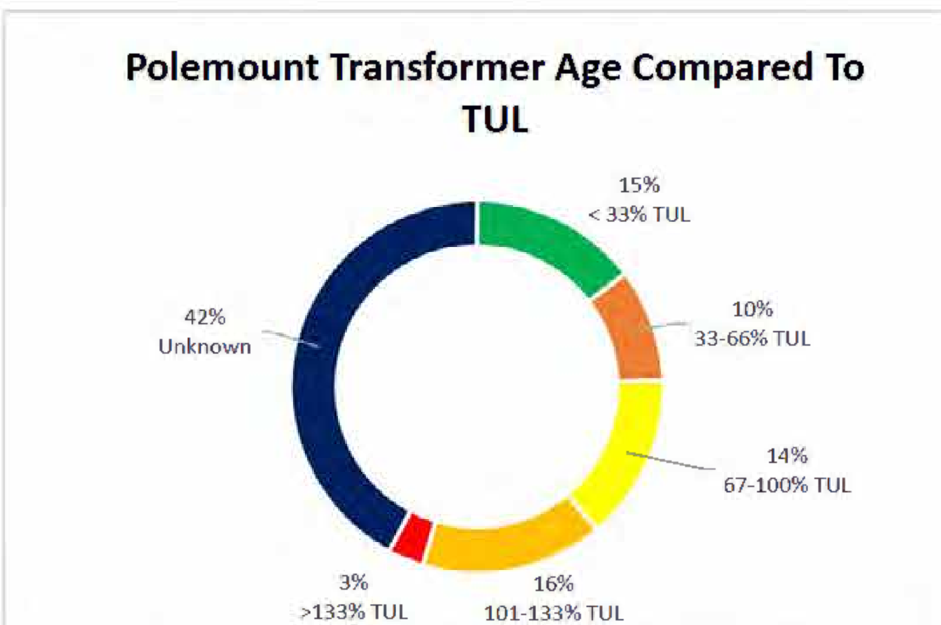


Figure 3-7: Age Summary Pole-Mount Transformer by TUL

Results

NOW owns 581 pole-mounted transformers. Valid HI results were calculated for 336 of these transformers. If service age was not listed, the HI was determined based on visual inspection results. The HI results for pole-mounted transformers are summarized in Table 3-8 and Figure 3-8.

The breakdown of HI scores shows that 8% of the transformers are in very good condition, 20% are in good condition, 19% are in fair condition, and 12% are in poor condition. Additionally, 42% of the pole-mounted transformers have an unknown HI due to insufficient data. The age results for pole-mounted transformers are shown in Figure 3-9.

Table 3-8: Pole-Mount Transformers HI Results by Service Area

Condition	Number of Pole-Mounted Transformers by Service Area				
	Cochrane	Iroquois Falls	Kapuskasing	Unknown Area	Total
Very Good	7	12	25	0	44
Good	61	11	42	0	114
Fair	51	18	39	0	108
Poor	48	10	12	0	70
Very Poor	0	0	0	0	0
Unknown HI	67	106	70	2	245
Total	234	157	188	2	581

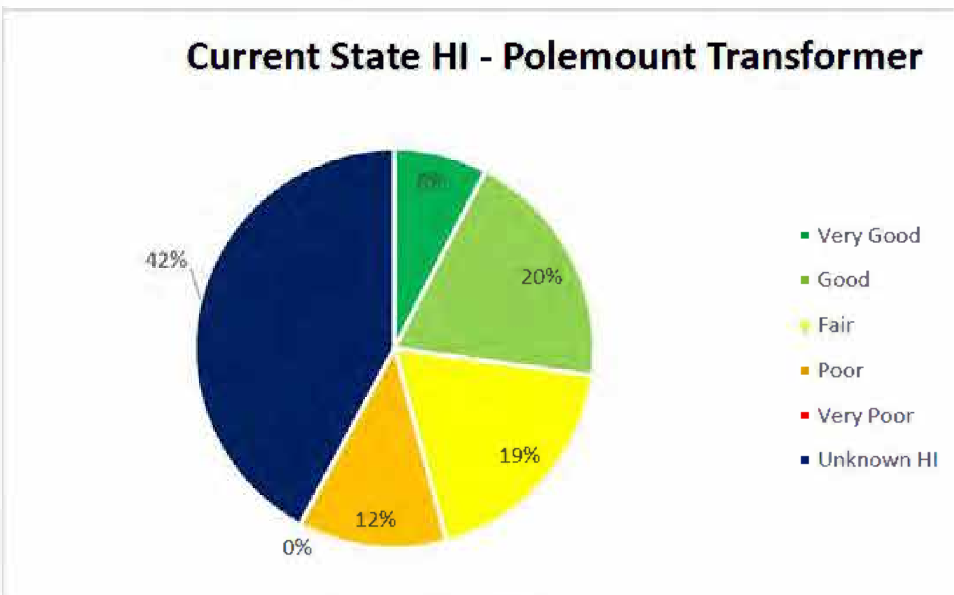


Figure 3-8: Pole-Mounted Transformer HI Results

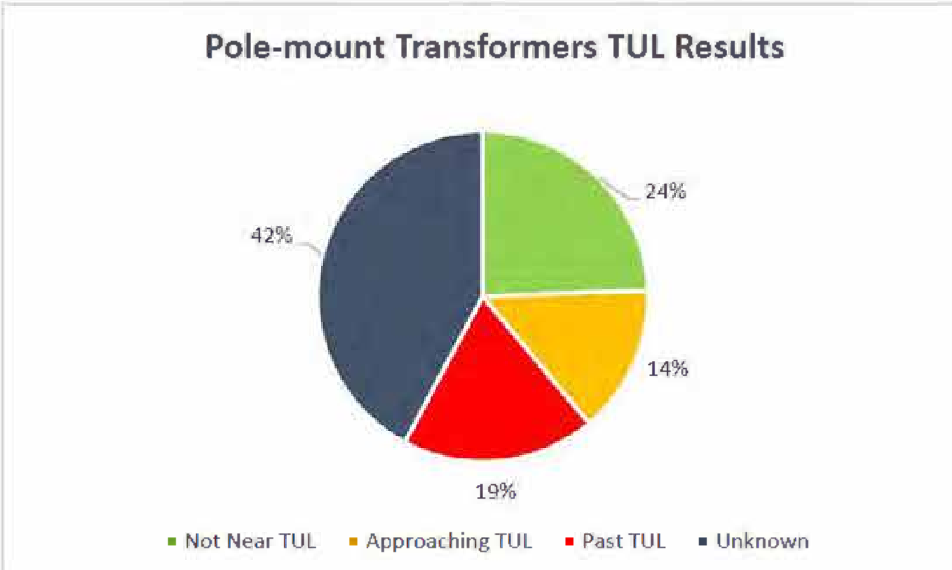


Figure 3-9: Pole-Mounted Transformer TUL Results

3.1.3. Pad-Mounted Transformers

Condition Assessment Methodology

NOW owns 26 pad-mounted transformers across its service areas. However, due to insufficient data, a valid Health Index (HI) could not be established for this asset class. The lack of detailed condition and age data makes it challenging to assess the current state and remaining life of these transformers accurately.

Typically, pad-mounted transformers are managed as run-to-failure assets, with minimal maintenance beyond visual inspections and IR scans. These transformers may be replaced during planned projects due to identifiable degradation, such as corrosion, road relocations, or upgrades prompted by customer load growth.

Most commonly, utilities replace pad mounted transformers as part of UG rebuild projects. Occasionally, a transformer will become overloaded due to changes in customer usage which can be detected by summing loads monitored with automated meter infrastructure and can lead to internal failures if not rectified. The HI values for pad-mount distribution transformers are calculated by considering a combination of service age, visual inspection results, and IR scan results.

Table 3-9 provides the HIF for pad-mounted transformers. NOW should consider collecting data for some or all of the HIF condition parameters to support future ACAs for pad-mounted transformers.

Table 3-9: Pad-Mount Transformer Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	2	B,C,D,E	3,2,1,0	6
			Total Score	**26**

Data Collection and Assumptions

A valid HI could not be established for this asset class due to poor data availability. Because of insufficient age data, the ages of the pad-mounted transformers were estimated based on the average age of pole-mount transformers on the same feeder as the pad-mount transformer. Following this approach, estimated ages were assigned to 100% of the pad-mount transformers.

Demographics

NOW owns 26 pad-mount transformers throughout its three service areas. The installation year is estimated for 100% of the pad-mount transformers based on the average age of the pole-mount transformers on the corresponding feeder. Figure 3-10 presents the estimated age demographics of the pad-mounted transformers, showing that most transformers fall within the 27-40 years old.

Figure 3-11 shows the age demographics of the pad-mount transformers compared to their TUL of 40 years. The majority of the transformers (58%) are within 67-100% of their TUL, indicating they are nearing the end of their useful life. Another 42% are within 33-66% of their TUL, indicating they are in mid-life.

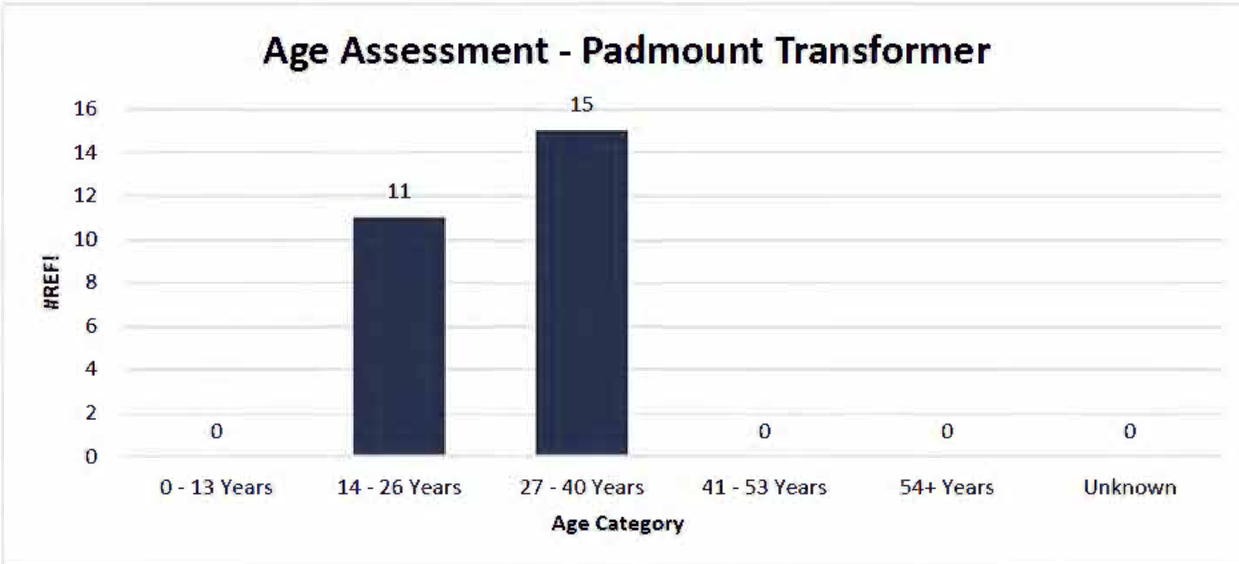


Figure 3-10: Pad-Mount Transformer Estimated Age Demographic

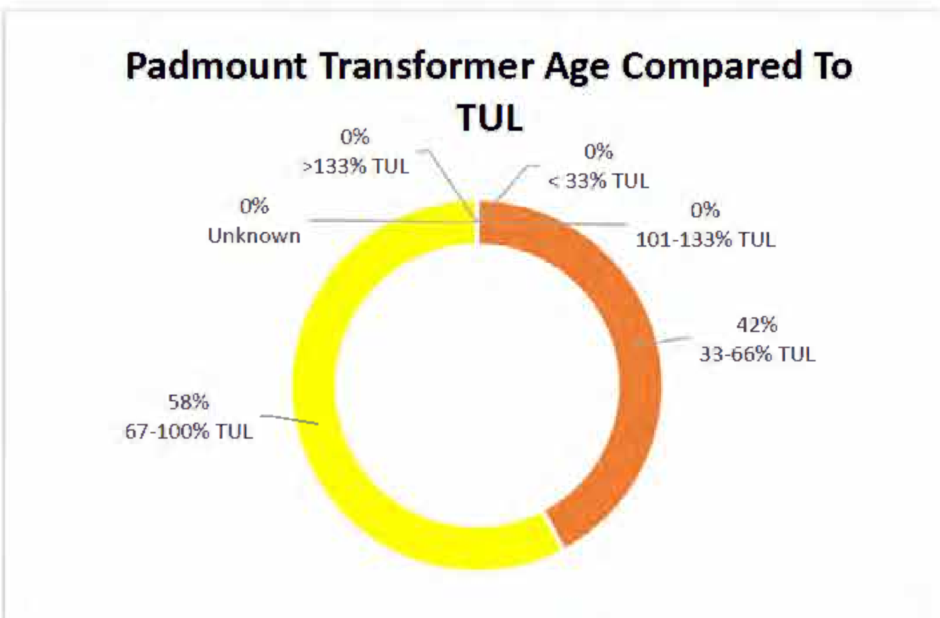


Figure 3-11: Pad-Mount Transformer Estimated Age Summary by TUL

Results

Age results for Pad-mount Transformers are shown in Figure 3-12 below.

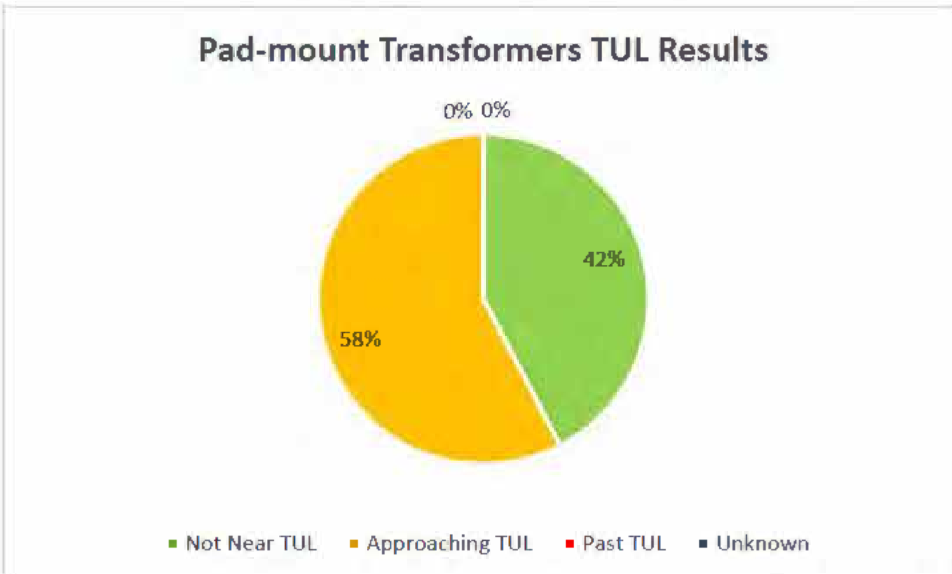


Figure 3-12: Pad-Mount Transformer TUL Results

3.1.4. Overhead Primary Conductors

Condition Assessment Methodology

OH conductor assets tend to be renewed when poles are replaced, when voltages are upgraded, or when lines are restrung for technical reasons. It is very rare that the conductor condition would drive a distinct replacement investment program. There is one recognized conductor risk, namely the tendency for small copper conductors to age at an accelerated rate and become brittle. Although laboratory tests exist to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for estimating the tensile strength of conductors and estimating the remaining life of an asset is the use of service age. BBA's recommended HIF for OH conductors is shown in Table 3-10.

Table 3-10: OH Conductor HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Small Conductor Risk	1	A,E	4,0	4
			Total Score	**12**

Data Collection and Assumptions

The asset information provided by NOW was utilized to complete the assessment of overhead (OH) conductors. However, a valid HI could not be established for this asset class due to poor data availability. Because of insufficient age data, the ages of the conductors were estimated based on the average age of pole-mounted transformers on the same feeder as the overhead conductor segments. Following this approach, estimated ages were assigned to 99% of the conductor line segments. Additionally, due to the unavailability of conductor length data, the analysis was conducted on conductor segments.

Demographics

NOW owns 1226 OH primary conductor segments across its three service areas. Figure 3-13 illustrates the age distribution of these conductors, with the majority (1,100 segments) estimated to be 21-40 years old, 114 segments in the 41-60 years range, and 12 segments of unknown age. Figure 3-14 compares these ages to their theoretical useful life (TUL) of 60 years. Most segments (90%) fall within 33-66% of their TUL, indicating they are mid-life, while 9% are nearing the end of their TUL.

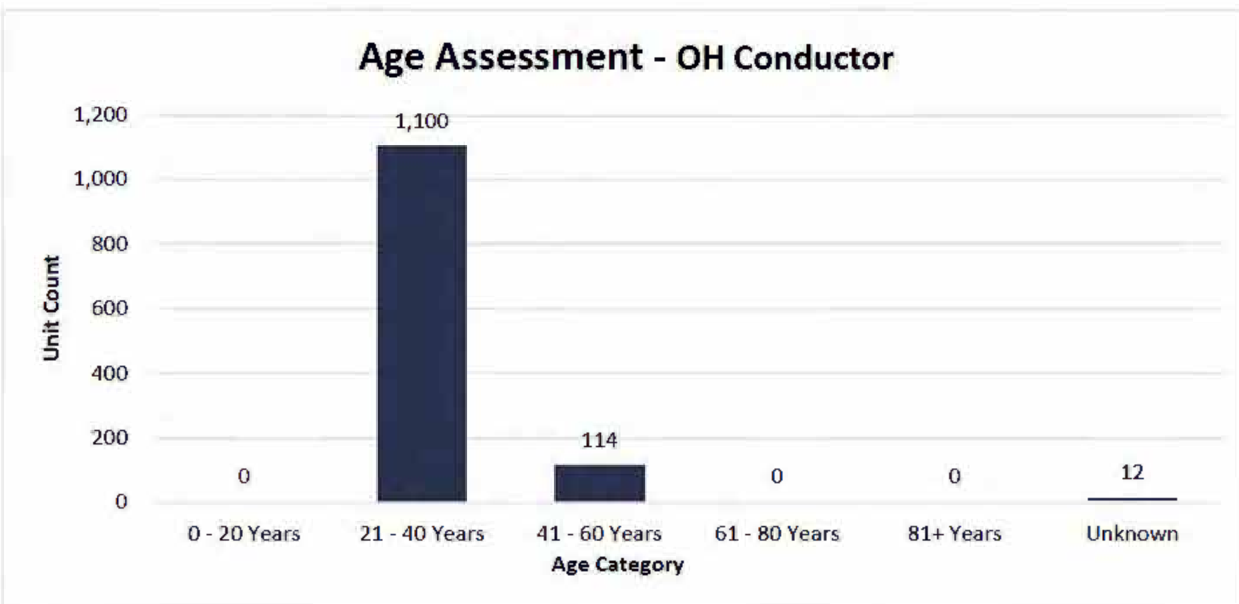


Figure 3-13: Primary OH Conductor Segments by Installation Year

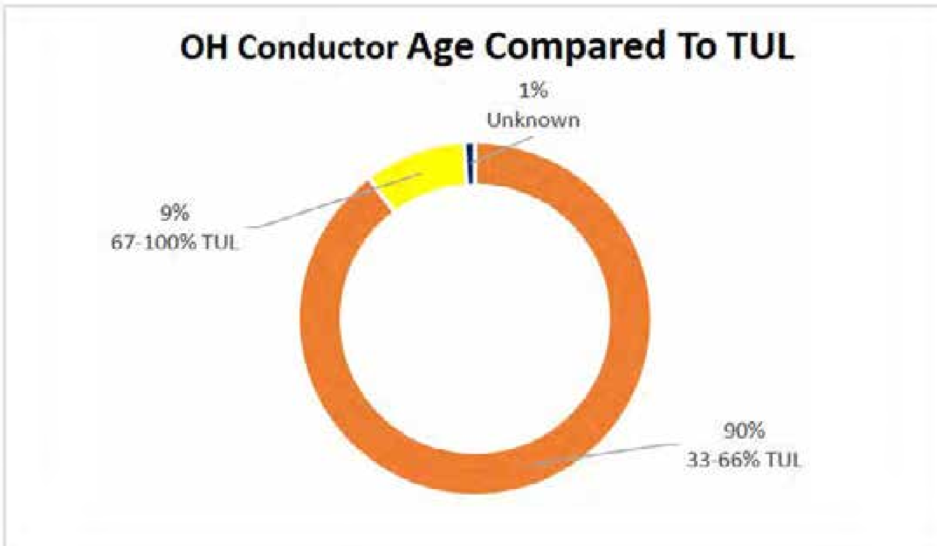


Figure 3-14: Primary OH Conductor Age Summary by TUL

Results

Age results for OH conductors are shown in Figure 3-15.

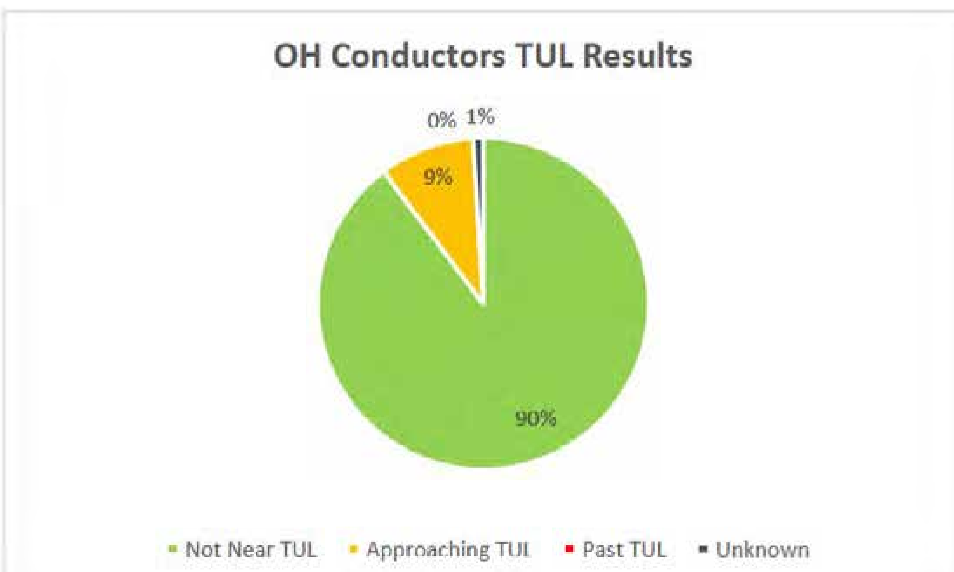


Figure 3-15: Primary OH Conductor TUL Results

3.1.5. Primary Underground Cables

Condition Assessment Methodology

Distribution UG primary cables are one of the more challenging assets in electricity systems from a condition assessment viewpoint. Although several test techniques, such as partial discharge testing, have become available over recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring cable failure rates and the impacts of in-service failures on reliability and operating costs. In recognition of these difficulties, cables are replaced when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs, become higher than the annualized cost of cable replacement.

Service age provides a reasonably good measure of the remaining life of cables with the lack of visual inspection for cable defects. As a minimum, age-based parameters and the knowledge of past failure instances will allow the comparison of a given cable segment to other cables of similar vintage. An additional parameter that can be considered is that any cable sections that have previously experienced a fault are considered a higher risk for recurrence although the data on this topic requires further research.

Many test labs are offering partial discharge ("PD") measurements to assess the condition of cables in service. PD testing of cables is performed online without disrupting the plant or facilities or offline when required. The data obtained from PD tests can provide critical information regarding the quality of cable insulation and its impact on cable system health. Table 3-11 provides the HIF for UG cables. NOW should consider collecting data for some or all of the HIF condition parameters to support future ACAs for UG cables.

Table 3-11: UG Cable HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	10	A,B,C,D,E	4,3,2,1,0	40
Cable Failure Analysis	10	A,B,C,D,E	4,3,2,1,0	40
Field Testing	10	A,B,C,D,E	4,3,2,1,0	40
Condition of Concentric Neutral	9	A,B,C,D,E	4,3,2,1,0	36
Outage Records in Last 5 Years	8	A,B,C,D,E	4,3,2,1,0	32
Loading History	5	A,B,C,D,E	4,3,2,1,0	20
			Total Score	**208**

Data Collection and Assumptions

A valid HI could not be established for this asset class due to poor data availability. Because of insufficient age data, the ages of the UG cable segments were estimated based on the average age of pole-mounted transformers on the same feeder as the UG cable segment. Following this approach, estimated ages were assigned to 100% of the UG Cable segments. Additionally, due to the unavailability of circuit length data, the analysis was conducted on cables segments.

Demographics

NOW owns 25 underground (UG) cable segments across its three service areas. The installation year for 100% of these segments has been estimated based on the average age of pole-mounted transformers on the corresponding feeder. Figure 3-16 presents the UG cable segments by their estimated age.

According to Figure 3-17 , the age demographics of primary UG cables in relation to their TUL of 25 years show that 64% of the segments are within 101-133% of their TUL, indicating they have slightly exceeded their expected lifespan. Additionally, 36% of the segments are over 133% of their TUL, suggesting they are well beyond their expected useful life. This data highlights that a significant portion of the UG cables is aging, with many already past their designed lifespan.

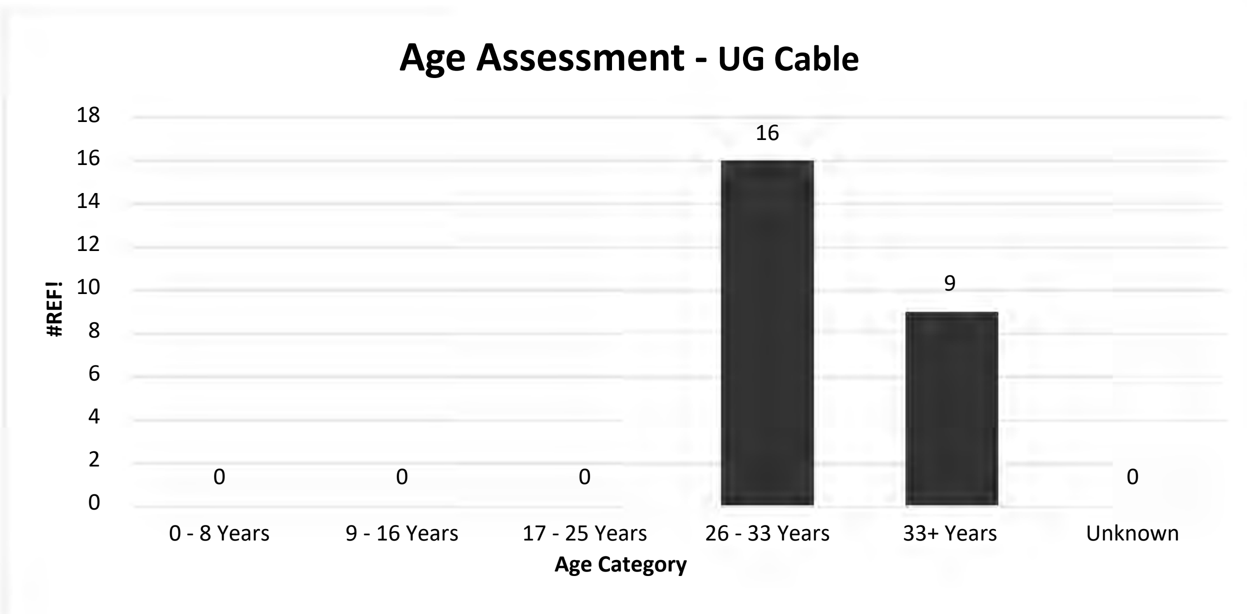


Figure 3-16: Primary UG Cable Segments by Estimated Installation Year

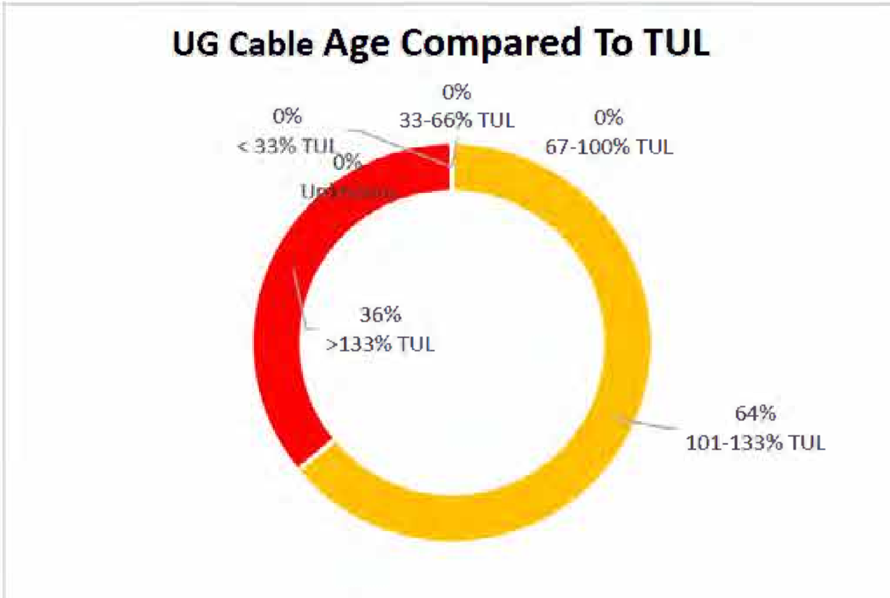


Figure 3-17: Primary UG Cable Age Summary by TUL

Results

Age results for UG Cables are shown in Figure 3-18 below. All of NOW's UG cables are estimated to be Past TUL.

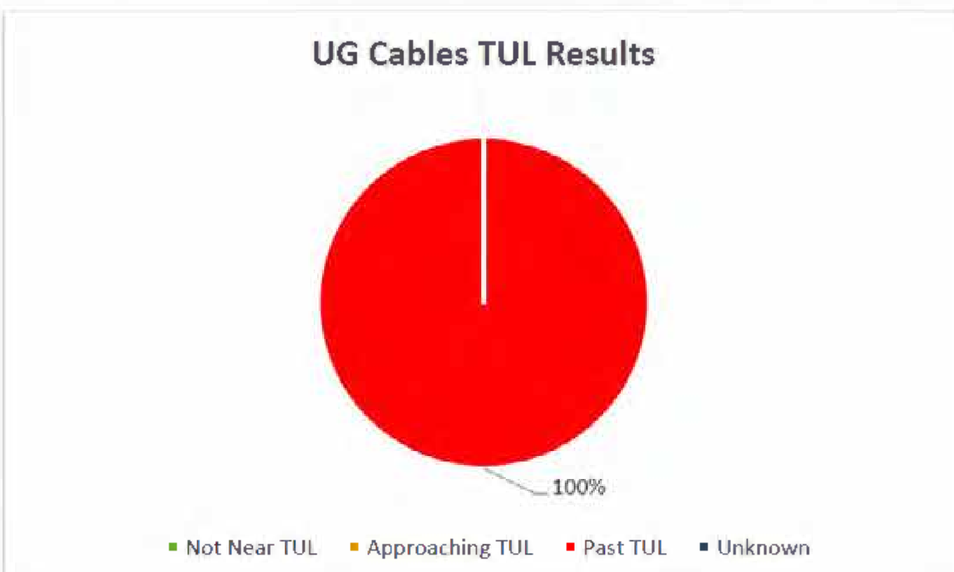


Figure 3-18: Primary UG Cable TUL Results

3.1.6. Overhead Switches

Condition Assessment Methodology

Overhead switches represent critical infrastructure for electrical utilities. The primary means of inspecting and maintaining switches are to visually identify dirt and corrosion and to use IR scans to find "hot" connections. Traditional air-insulated, handle-operated switches are highly maintainable and can often be extended indefinitely and nearly completely rebuilt on the pole. Newer single-piece devices can also be maintained but would generally be removed from the pole and maintained in a shop setting.

The HI for distribution load-break switches is calculated by considering the overall condition of the asset. Table 3-12 provides the HIF for Overhead switches. NOW should consider collecting data for some or all of the HIF condition parameters to support future ACAs for overhead switches.

Table 3-12: UG Cable HI Algorithm

Condition Criteria	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	2	B,C,D,E	3,2,1,0	6
			Total Score	**14**

Data Collection and Assumptions

A valid HI could not be established for this asset class due to poor data availability. Because of insufficient age data, the ages of the overhead switches were estimated based on the average age of pole-mounted transformers on the same feeder as the switch. Following this approach, estimated ages were assigned to 97% of the overhead switches.

Demographics

NOW owns 143 overhead switches throughout its three service areas. The installation year is known for 97% of the overhead switches. Figure 3-19 presents the estimated age demographics of the overhead switches, showing that most switches fall within the 16-30 years and 31-45 years age categories.

Figure 3-20 shows the age demographics of the overhead switches compared to their theoretical useful life (TUL) of 45 years. The majority of the switches (55%) are within 33-66% of their TUL, indicating they are mid-life. Another 38% are within 67-100% of their TUL, nearing the end of their useful life, while 4% have exceeded their TUL. Additionally, 3% of the switches have an unknown age.

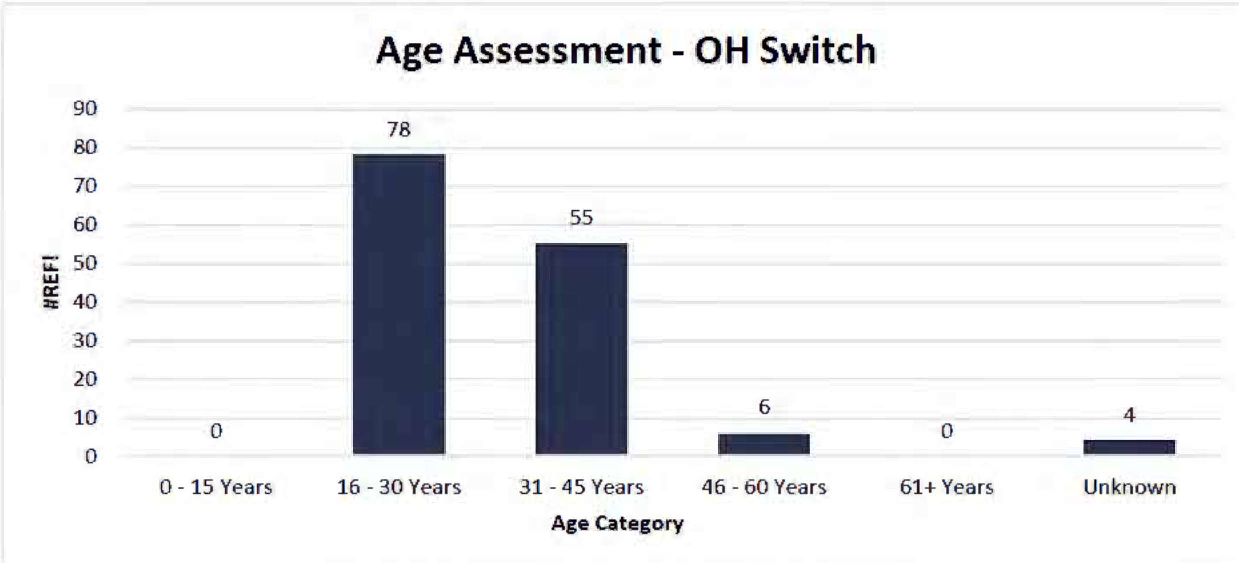


Figure 3-19: Overhead Switch by Installation Year

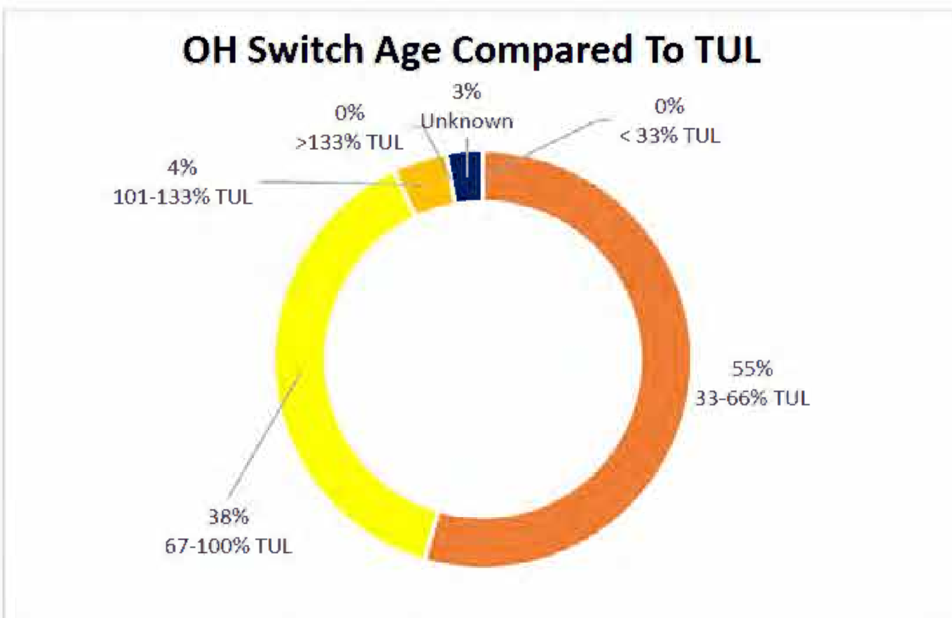


Figure 3-20: Overhead Switch Age Summary by TUL

Results

Age results for OH Switches are shown in Figure 3-21 below.

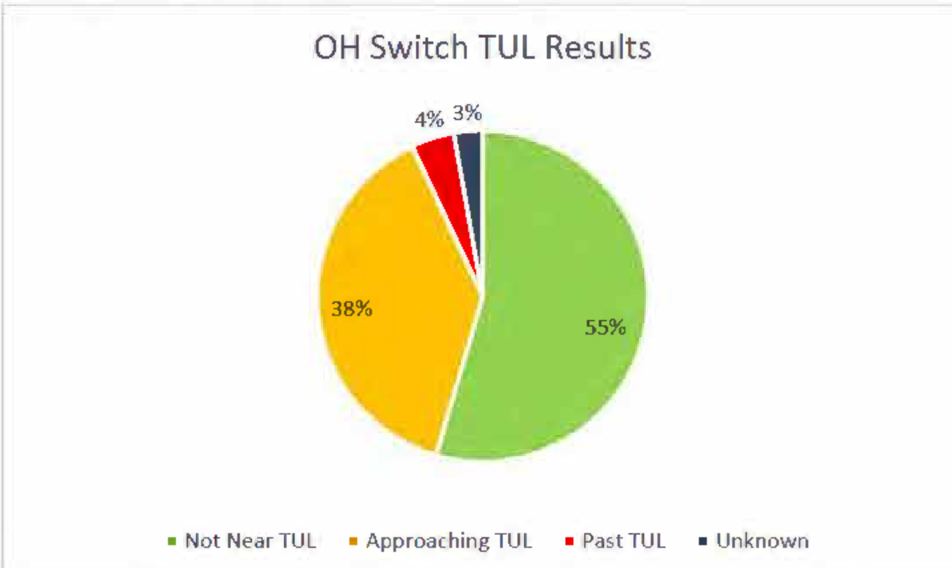


Figure 3-21: OH Switch TUL Results

3.1.7. Power Transformers

Condition Assessment Methodology

Power transformers are the single most critical asset class owned by an LDC. Each transformer can be valued in the range of hundreds of thousands to millions of dollars and can affect a significant number of customers. Degradation mechanisms include loss of insulation or oil quality due to overload or low-level internal faults causing heating, arcing, and/or physical deterioration such as corrosion or failed cooling systems.

Table 3-13 below provides the power transformer HI algorithm. The HI for power transformers is calculated considering both the service age, dissolved gas analysis, oil quality, and overall visual inspection results. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 3-13: Power Transformer HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Dissolved Gas Analysis	10	A,E	4,0	40
Oil Quality	8	A,C,E	4,2,0	32
Overall Condition	8	A,B,C,D,E	4,3,2,1,0	32
			Total Score	**120**

Data Collection and Assumptions

NOW's inspection records and power transformer registry were the primary sources used to complete the condition assessment. The inspections data provided by NOW were conducted between. Service age information was available for 92% of NOW's power transformers, while data on dissolved gas analysis, oil quality, and overall visual condition was available for 100% of the transformers. The average DAI for power transformers is 99%

Demographics

NOW owns a total of 13 power transformers. The service age is known for 92% of the power transformers. Figure 3-22 presents the age distribution of the power transformers.

Figure 3-23 summarizes the age demographics by TUL. The TUL for power transformers is 45 years. The chart indicates that a significant portion of the power transformers have surpassed their expected service life, with 62% of the units exceeding 133% of their TUL. Additionally, 31% of the transformers are between 101-133% of their TUL, indicating they are past their anticipated lifespan. Additionally, 8% of the power transformers have an unknown age.

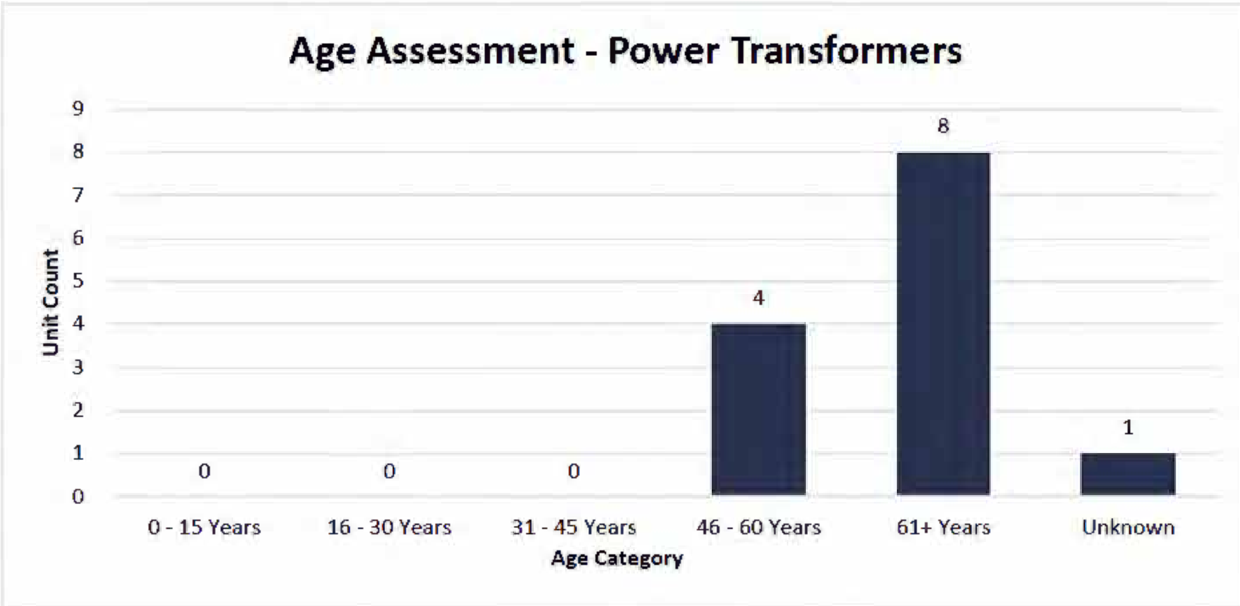


Figure 3-22: Power Transformer Age Demographics

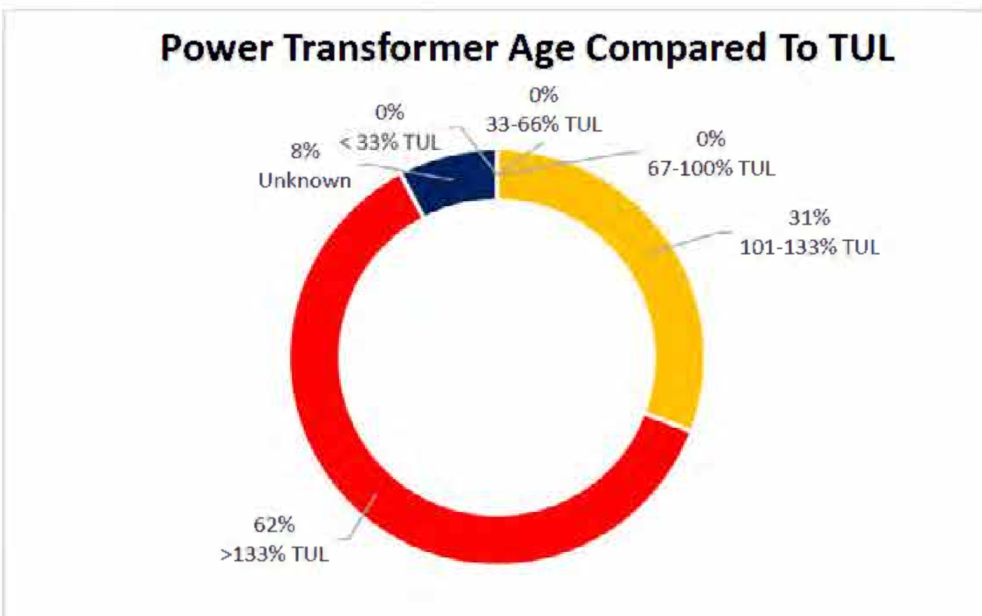


Figure 3-23: Age Summary of Power Transformers by TUL

Results

NOW owns 13 power transformers and valid HI results were calculated for all of them. The HI results for power transformers are presented in Figure 3-24. The majority of NOW's power transformers are in Fair or Poor condition. The age results for power transformers are shown in Figure 3-25. The majority of NOW's power transformers are Past TUL.

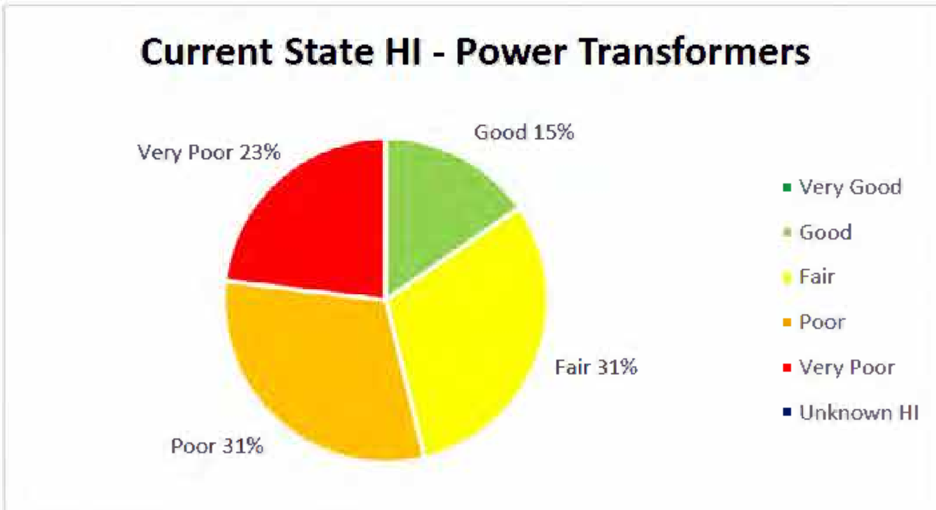


Figure 3-24: Power Transformer HI Results

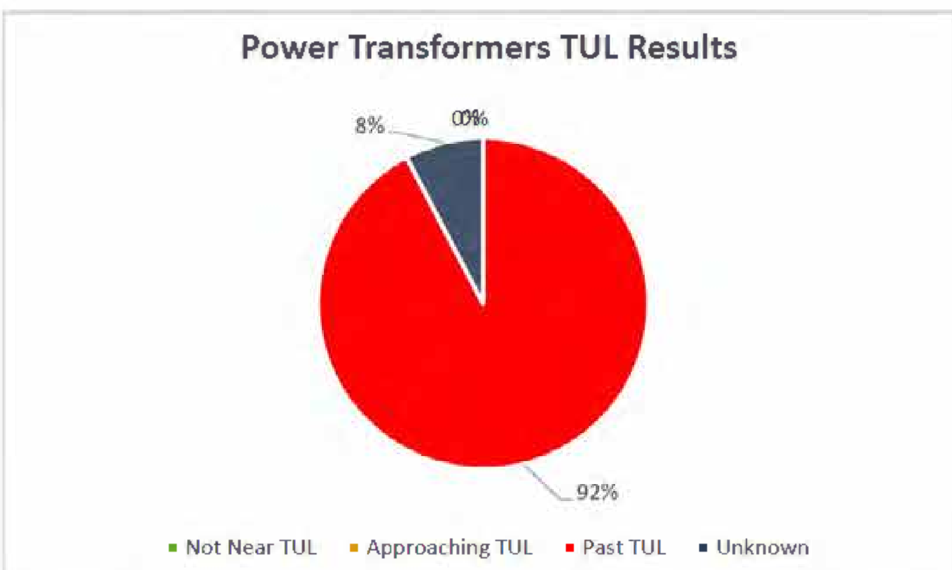


Figure 3-25: Power Transformer TUL Results

3.1.8. Power Transformer Tap Changers

Condition Assessment Methodology

Power transformers tap changers are essential for regulating voltage levels, ensuring stable and reliable power delivery to customers. The health of tap changers is assessed based on Dissolved Gas Analysis (DGA), Oil Quality, and Overall Condition. Degradation mechanisms include contamination of insulating oil, accumulation of dissolved gases indicating potential faults, wear and tear from mechanical operations, and physical deterioration of contacts or control systems.

Table 3-14 provides the power transformer tap changer HI algorithm. The HI for power transformer tap changers is calculated using both the service age, dissolved gas analysis and oil quality. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 3-14: Power Transformer Tap Changer HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	9	A,B,C,D,E	4,3,2,1,0	36
Dissolved Gas Analysis	6	A,E	4,0	24
Oil Quality	5	A,C,E	4,2,0	20
			Total Score	**80**

Data Collection and Assumptions

NOW's inspection records and asset registry were the primary sources used to complete the condition assessment of power transformer tap changers. The visuals inspections data provided by NOW were conducted in April 2023. Service Age was available for 66% of NOW's power transformer tap changers. Dissolved Gas Analysis and Overall Visual Inspection results were available for 100% of the power transformer tap changers. The average DAI for NOW's power transformer tap changers is 85%.

Demographics

NOW owns 3 power transformer tap changers. Figure 3-26 presents the age distribution of the tap changers. The service age is known for two of the three power transformer tap changers. Figure 3-27 provides an age summary by TUL. The TUL for power transformer tap changers is 30 years. For the two out of three tap changers with available service age data, it is evident that these assets have significantly exceeded their TUL.

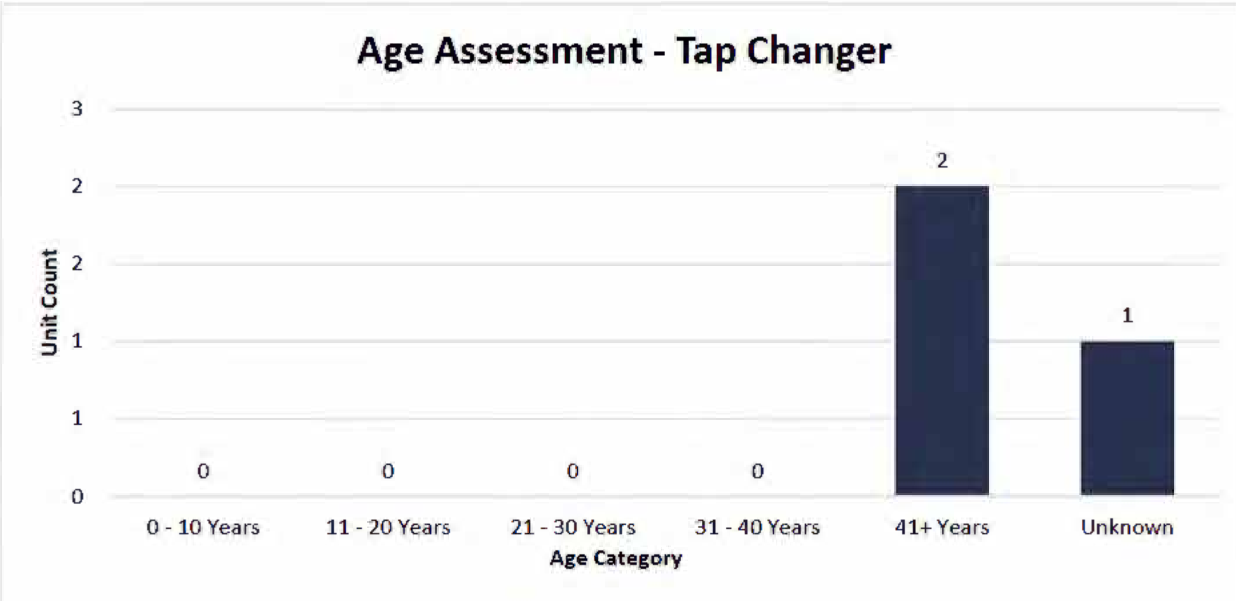


Figure 3-26: Age Demographics of Power Transformer Tap Changers

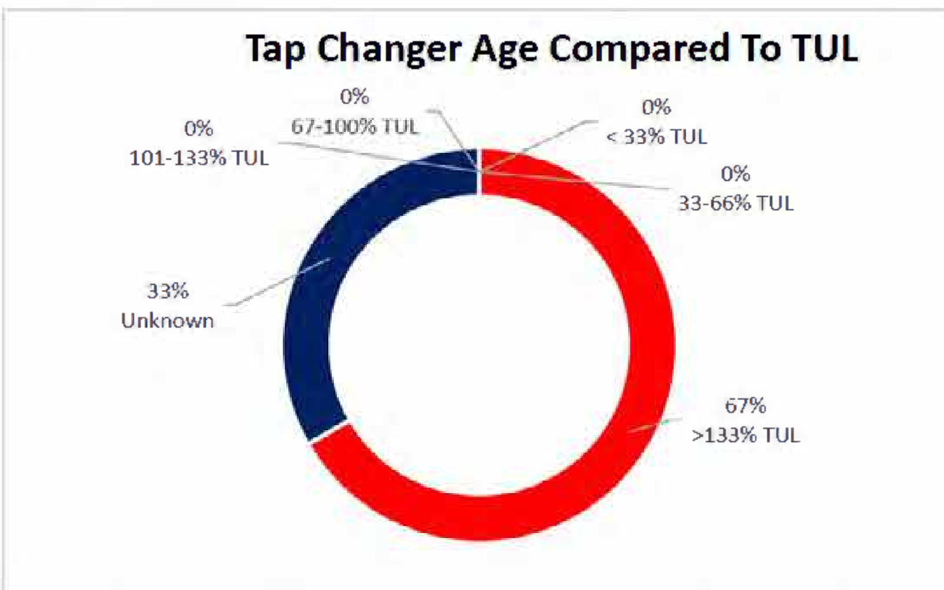


Figure 3-27: Power Transformer Tap Changer Age Summary by TUL

Results

Valid HI results were calculated for two of the three power transformer tap changers. HI results for power transformer tap changers are shown in Figure 3-28 below. Two of the three power transformer tap changers have a Poor HI, while the third tap changer lacked sufficient data to generate a valid HI. The age results of tap chargers are presented in Figure 3-29.

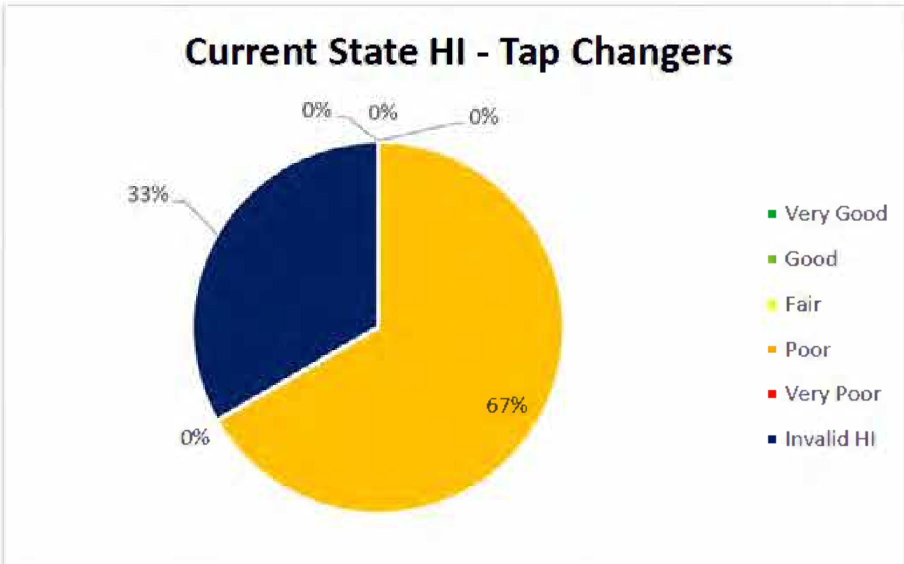


Figure 3-28: Power Transformer Tap Changer HI Results

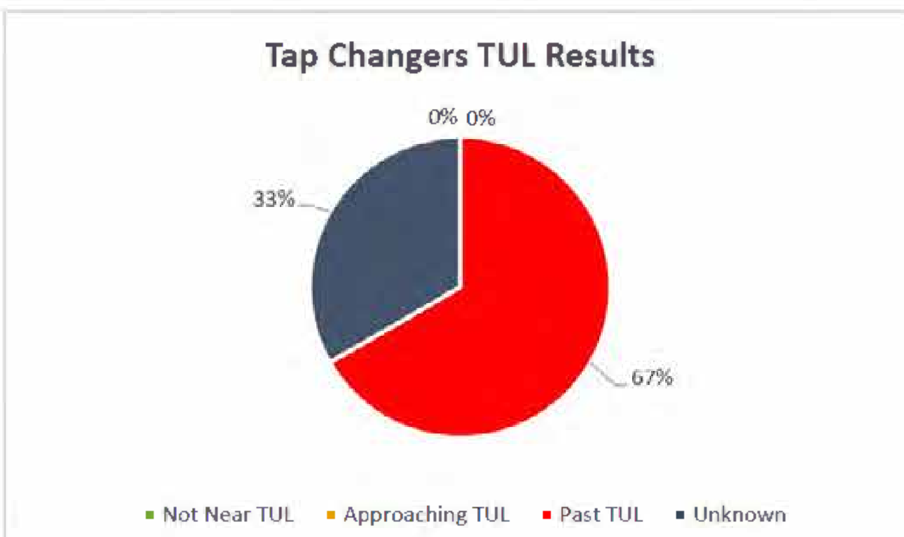


Figure 3-29: Power Transformer Tap Changer TUL Results

3.1.9. Station Switchgear

Condition Assessment Methodology

The HI for station switchgear units is calculated by considering a combination of service age and inspection results. Table 3-15 summarizes the methodology to combine these criteria into an overall HI. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 3-15: Station Switchgear HI Algorithm

Condition Criteria	Weight	Ranking	Numerical Grade	Max Score
Service Age	1	A,B,C,D,E	4,3,2,1,0	4
Electrical Testing	3	A, E	4,0	12
Visual Condition	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**32**

Data Collection and Assumptions

NOW currently owns six switchgear units. The HI for these units is calculated using service age, electrical testing, and visual inspection results. Visual inspections were conducted between July to September 2023. Service age data is available for 67% of the switchgear units, visual inspection results for 50%, and electrical testing results for 67%. The average DAI for station switchgears was 58%.

Demographics

NOW owns 6 switchgear units, and the service age is known for 67% of them. Figure 3-30 presents the age distribution of station switchgear units. Figure 3-31 shows the age demographics of the station switchgear units by TUL, which shows that most switchgear units are past their TUL. The TUL for switchgears is 40 years.

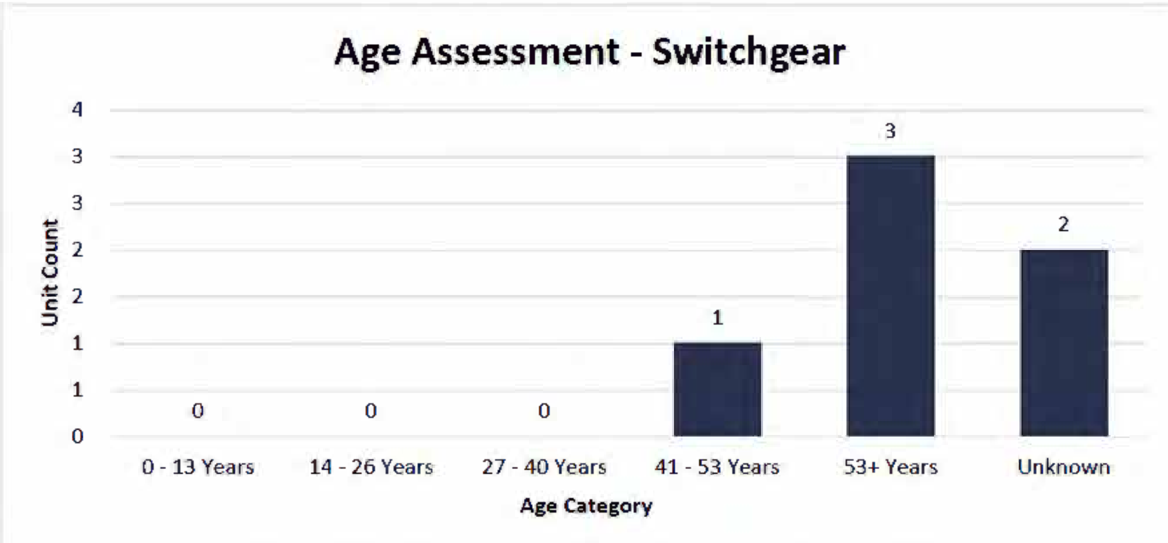


Figure 3-30: Age Demographics of Station Switchgear Units

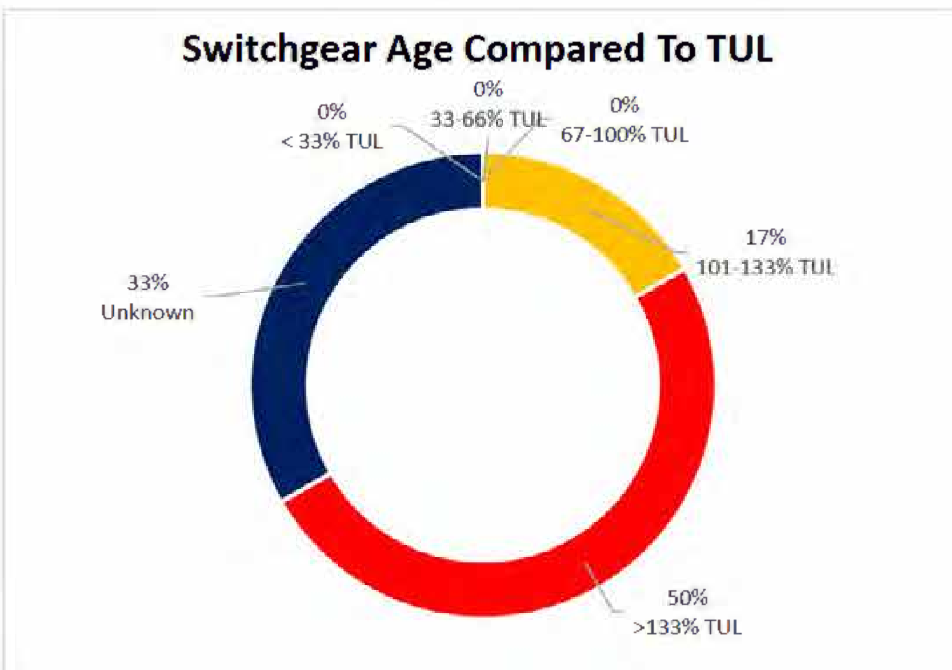


Figure 3-31: Age Summary of Station Switchgear Units by TUL

Results

Valid HI were calculated for 3 of the station switchgears. The HI results for station switchgears are presented in Figure 3-32 below. The age results for station switchgears are presented in Figure 3-33.

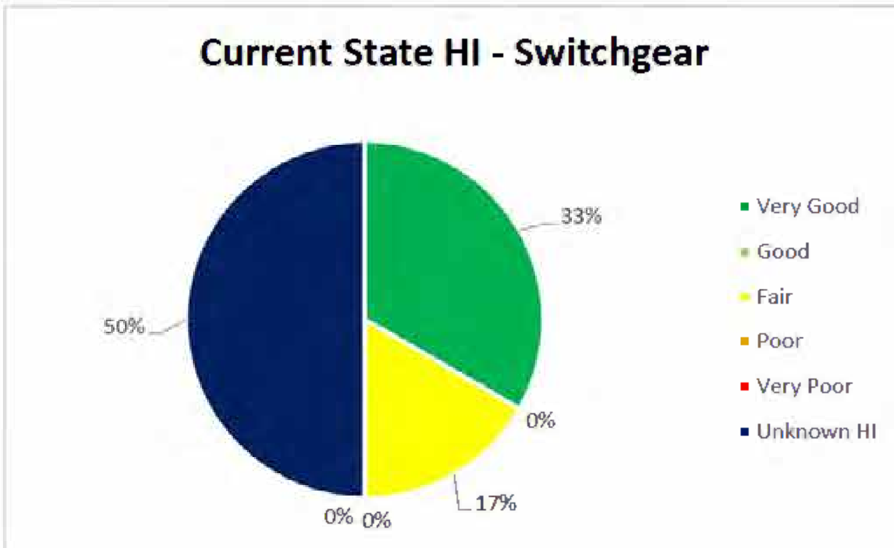


Figure 3-32: Station Switchgear HI Results

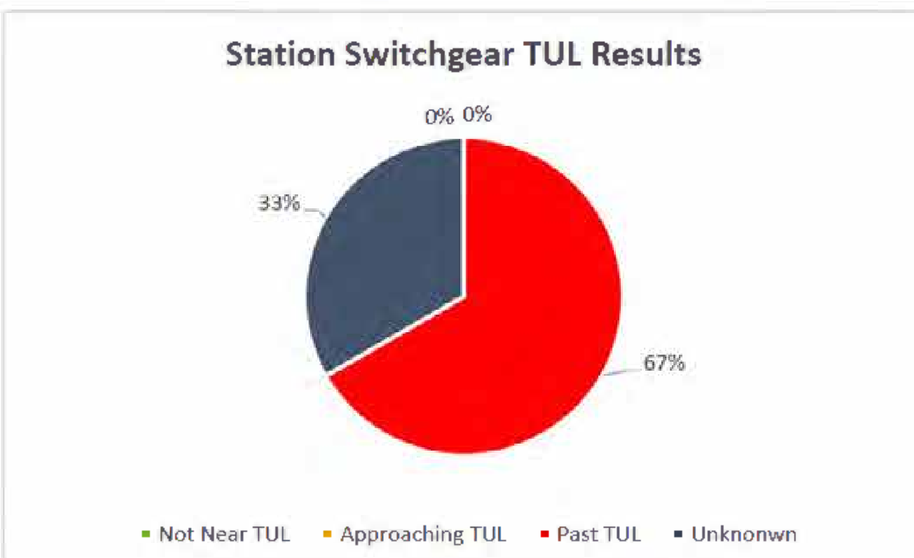


Figure 3-33: Station Switchgear TUL Results

4. Conclusions & Recommendations

4.1. Conclusions

A complete ACA framework for NOW represents an integral component of its broader AM framework, enabling it to proactively manage its 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, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging the HI insights allows for NOW'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. The following sections target additional condition parameters that NOW might consider implementing to work towards a best practice HI formulation for each asset class. Recommendations are also provided to improve the quality of data currently available to standardize the data collection process for future iterations of the ACA.

4.2. Recommendations for Distribution Assets

4.2.1. Wood Poles

NOW's inspection records generally provided useful condition information for wood poles. Inspection results were kept separate from the asset registry. BBA found that the formatting of the inspection results was not the most efficient. To improve data quality, NOW should consider consolidating its inspection records and asset registry. This would allow asset information and inspection records to be combined and correlated easily for future condition assessments.

There was also a lack of testing information for NOW's wood poles. Inspection services should be advised to give consistent reporting of remaining strength, preferably as a percentage of remaining life. Pole testing should be completed for all wood poles over ten years of age to verify the condition.

4.2.2. Pole-Mount Transformers

It is recommended that NOW establish transformer demographics for all distribution transformers as part of a regular inspection. The inspection data currently being collected for pole-mount transformers is detailed and comprehensive.

The following additional condition parameters may provide useful insight subject to the economics of assessing the remaining lives of NOW's pole-mounted transformer population for longer-term planning:

- Peak loading history.
- IR Scan

4.2.3. Pad-Mount Transformers

At a minimum, age and condition data should be made available for all units. Because of the potential for transformers to be removed from one location, rehabilitated and then installed elsewhere, transformers are often tracked by serial number.

As part of the Asset Management Plan, an enhanced formulation based on criteria similar to pad-mounted switchgear assets would give a better indication of asset health. Suggested additional parameters include, as a minimum, condition of structures/pads and IR scan results.

4.2.4. Overhead Conductors

NOW will need to improve the age availability of OH conductors. It is recommended that NOW record the Facility ID of the closest pole to each conductor line segment. Once this is done, the age of each line segment can be estimated based on the age of the closest distribution pole. It is recommended that NOW also prioritize recording the wire length for all their OH Conductors.

NOW should also ensure that all OH conductor segments of #4 or #6 copper are tagged in the asset registry. These small copper conductors tend to age at an accelerated rate and become brittle. This condition parameter is important to include in the OH conductor Health Index Formulation ("HIF").

4.2.5. Underground Cables

Now will need to improve the age availability of UG cables. Service age provides a reasonably good measure of the remaining life of UG cables, while additional knowledge of past failure instances allows for comparison between cable segments of similar vintage. It is recommended that NOW also prioritize recording the wire length for all their UG Cables.

Recognized HI guides recommend a multi-parameter HIF for UG cables. It is recommended that NOW perform cable failure analysis, conduct cable testing, and track cable outages by cable/circuit ID to support future ACAs for UG cables.

4.2.6. OH Switches

Condition data from visual inspection should be collected and translated into condition scores (A, B, C, D, E) and consolidated in the asset registry. Electronic field data collection methods are preferred. In addition to the data currently being collected, a best-practice formulation may consider some additional condition parameters such as:

- Condition of operating mechanism
- Condition of terminations
- IR Scan

4.3. Station Assets

4.3.1. Power Transformers and Tap Changers

Power transformers are a critical asset class and should be managed under the context of a thorough AM Plan. Inspection results for NOW's power transformers and tap changers are detailed and comprehensive.

There are several additional condition parameters that NOW can collect moving forward to improve the accuracy of the power transformer HI and align the formulation with industry best-practices:

- Condition of Bushings
- Condition of Conservator
- Condition of Gaskets and Seals
- Condition of Transformer Connectors
- Condition of Tap Changers

4.3.2. Station Switchgears

The data availability for NOW's station switchgears is good. BBA recommends adding age data into the asset registry.

Appendix A: Condition Parameters Grading Tables

A.1 Wood Poles

Table A-1: Criteria for Wood Pole Service Age

Condition Rating	Age
A	0 to 15 years
B	16 to 30 years
C	31 to 45 years
D	46 to 60 years
E	61 years or older

Table A-2: Criteria for Wood Pole Guy Wire Condition

Condition Rating	Corresponding Condition
A	No issues noted
C	One issue noted
E	Multiple issues noted

Table A-3: Criteria for Wood Pole Cross Arm Condition

Condition Rating	Corresponding Condition
A	Numerical Grade 4
E	Numerical Grade 0

Table A-4: Criteria for Wood Pole Bent, Cracked, Broken, or Rotten

Condition Rating	Corresponding Condition
A	Numerical Grade 4
B	Numerical Grade 3
C	Numerical Grade 2
D	Numerical Grade 1
E	Numerical Grade 0

Surface Wear and Scaling – See Table A-4

Wood Pecker, Insect Damage, Bird Nests – See Table A-4

Burn, Lightning Damage – See Table A-4

A.2 Pole-Mount Transformers

Table A-5: Pole-Mounted Transformers Service Age

Condition Rating	Age
A	0 to 13 years
B	14 to 26 years
C	27 to 40 years
D	41 to 53 years
E	54 years or older

Table A-6: Pole-Mounted Transformers Paint Corrosion

Condition Rating	Corresponding Condition
A	Rating 5
B	Rating 4
C	Rating 3
D	Rating 2
E	Rating 1

Table A-7: Pole-Mounted Transformer Oil Leaks

Condition Rating	Corresponding Condition
A	Yes
E	No

Grounding System – See Table A-6

Heating or Discolouration – See Table A-6

Condition of Connections – See Table A-6

A.3 Power Transformers and Tap Changers

Table A-8: Power Transformer Service Age

Condition Rating	Age
A	0 to 15 years
B	16 to 30 years
C	31 to 45 years
D	46 to 60 years
E	61 years or older

Table A-9: Tap Changers Service Age

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 30 years
D	31 to 40 years
E	41 years or older

Table A-10: Power Transformer Visual Condition Grading

Condition Rating	Corresponding Condition
A	Visual Inspection did not identify any areas of concern
E	Visual Inspection identified one or more areas of concern

Table A-11: Gas Concentration (ppm) Limits for Power Transformers and Tap Changers.[1]

<table>
<tr><th rowspan="3">Gas</th><th colspan="4">O2/N2 Ratio <= 0.2</th><th colspan="4">O2/N2 Ratio >0.2</th></tr>
<tr><th colspan="4">Transformer Age in Years</th><th colspan="4">Transformer Age in Years</th></tr>
<tr><th>Unknown</th><th>1-9</th><th>10-30</th><th>>30</th><th>Unknown</th><th>1-9</th><th>10-30</th><th>>30</th></tr>
<tr><td>H_2</td><td>80</td><td colspan="2">75</td><td>100</td><td>40</td><td colspan="3">40</td></tr>
<tr><td>CH_4</td><td>90</td><td>45</td><td>90</td><td>110</td><td>20</td><td colspan="3">20</td></tr>
<tr><td>C_2H_6</td><td>90</td><td>30</td><td>90</td><td>150</td><td>15</td><td colspan="3">15</td></tr>
<tr><td>C_2H_4</td><td>50</td><td>20</td><td>50</td><td>90</td><td>50</td><td>25</td><td colspan="2">60</td></tr>
<tr><td>C_2H_2</td><td>1</td><td colspan="3">1</td><td>2</td><td colspan="3">2</td></tr>
<tr><td>CO</td><td>900</td><td colspan="3">900</td><td>500</td><td colspan="3">500</td></tr>
<tr><td>CO_2</td><td>9000</td><td>5000</td><td colspan="2">10000</td><td>5000</td><td>3500</td><td colspan="2">5500</td></tr>
</table>

[1] IEEE Std. C57.104, "IEEE Guide for the Interpretation of Gases Generated in Mineral Oil-Immersed Transformers," 2019.

Table A-12: Gas Rate of Change Limits for Power Transformers and Tap Changers[1]

Gas	Maximum (ppm) variation between consecutive DGA samples	
	O2/N2 Ratio <= 0.2	O2/N2 Ratio >0.2
H_2	40	25
CH_4	30	10
C_2H_6	25	7
C_2H_4	20	
C_2H_2	Any Increase	
CO	250	175
CO_2	2500	1750

Table A-13: Power Transformer and Tap Changers DGA Results

Condition Rating	Corresponding Condition
A	All parameters within acceptable limits
B	1 parameter does not meet acceptability limits
C	2 parameters do not meet acceptability limits
D	3 parameters do not meet acceptability limits
E	4 or more parameters do not meet acceptability limits

Table A-14: Power Transformer and Tap Changers Oil Quality

Test	Station Transformer Voltage Class		Grade
	U ≤ 69 kV	69 kV ≤ U ≤ 230 kV	
Acid Number	≤0.05	≤0.04	A
	0.05-0.20	0.04-0.15	C
	≥0.20	≥0.15	E
Interfacial Tension [mN/m]	≥30	≥35	A
	25-30	30-35	C
	≤25	≤30	E
Dielectric Strength [kV]	>23 (1 mm gap)	>28 (1 mm gap)	A
	≤40	≤47	E
Water Content [ppm]	<35	<25	A
	≥35	≥25	E

A.4 Station Switchgear

Table A-15: Criteria for Switchgear Service Age

Condition Rating	Age
A	0 to 13 years
B	14 to 26 years
C	27 to 40 years
D	41 to 53 years
E	54 years or older

Table A-16: Station Switchgear Visual Condition

Condition Rating	Corresponding Condition
A	No issue noted in Visual Inspection
B	One issue noted in Visual Inspection
C	Two issues noted in Visual Inspection
D	Three issues noted in Visual Inspection
E	Four or more issues noted in Visual Inspection

Table A-17: Switchgear Electrical Condition

Condition Rating	Corresponding Condition
A	Acceptable
E	Not Acceptable

Appendix D-1

TECHNICAL REPORT
Destroyes & Mill
Substation Maintenance

ELECTEKPOWER

TECHNICAL REPORT

Destroyes & Mill Substation Maintenance

Prepared for:

Northern Ontario WIRES Inc.

287 Teefy Street
Iroquois Falls, Ontario
P0L 1C0

Prepared by:
Electek Power Services
12-868 Falconbridge Road
Sudbury, Ontario
P3A 5K7

Electek Reference #: 23068448
Customer Purchase Order: 3258 & 3301

Prepared by: Gary Taylor
Field Service Manager

Date: August 2023

ELECTEKPOWER

TECHNICAL REPORT

August 15, 2023

Northern Ontario Wires
287 Teefy Street
Iroquois Falls, Ontario
P0L1C0

Attention: Mr. Marc Belanger

Subject: Destroyes & Mill Substation Preventative Maintenance

Customer PO: 3258 & 3301
Electek Ref.: 23068448

Dear Sir,

Please find attached our technical report pertaining to the preventative maintenance testing and inspections performed at the Destroyes & Mill substations in July of 2023.

In general the equipment was found to be in fair operating condition. We have attached a brief summary of observations and recommendations that should be addressed.

Thank you for the opportunity to be of service. If you have any questions concerning this report, please do not hesitate to contact myself at (705) 507-1329.

Regards,

Gary Taylor
Field Service Manager
Northern Ontario

SUMMARY

Destroyes Substation

Power Transformer

Observations

- Electrical test results – Acceptable, see attached
- Visual inspection
  - Primary junction box was drained of oil and cleaned. A new gasket was installed on the cover and box filled with new Voltesso 35 to proper level. See attached pictures.
  - A leak was found at the conservator valve. Union fitting was tightened, continue to monitor. See attached picture.
  - Conservator was found empty, (2) barrels of oil were added to bring unit to proper level. See attached picture.
- Oil analysis
  - Oxidation inhibitor is below acceptable limit.
  - Moisture content exceeds IEEE limits.

Recommendations

- Inhibitor should be added to the unit in order to preserve general oil qualities.
- Monitor conservator valve leak. If worsens replace fittings.
- Continue performing routine preventative maintenance testing.
- Resample unit annually to better trend rate of rise.

Switchgear

Observations

- Electrical test results – Acceptable, see attached
- Visual inspection
  - Switchgear was found very dirty.
  - Switches were all cleaned, lubricated and exercised.
  - Cell gaskets had fallen on bus. Gaskets were glued back in place.

Recommendations

- Perform routine preventative maintenance testing, inspections and cleaning on a more frequent basis.

Mill Substation

Power Transformer

Observations

- Electrical test results
    - Power factor significantly exceeds acceptable limits. No previous results were available for comparison.
    - Secondary winding resistance exceeds acceptable limits. No previous results were available for comparison.
- Visual inspection
    - Transformer is leaking from the snorkel & manhole cover. See attached picture.
    - Primary junction box has been drained of oil sometime over the years in service. The primary connections are duct sealed and taped with 130C.
    - Transformer is down to primer and rusting in areas.
- Oil analysis
    - Oxidation inhibitor is below acceptable limit.
    - Moisture content exceeds IEEE limits.

Recommendations

- Inhibitor should be added to the unit in order to preserve general oil qualities.
- Replace manhole cover and snorkel gaskets.
- Continue performing routine preventative maintenance testing.
- Resample unit in 6 months to better trend rate of rise.
- Consider having the unit painted.

Switchgear

Observations

- Electrical test results – Acceptable, see attached
- Visual inspection
    - Switchgear was found very dirty.
    - Switches were all cleaned, lubricated and exercised.
    - PT fuse covers are burnt. Most fuses are open. See attached picture.

Recommendations

- Consider removing PT's from switchgear as there no longer in use.
- Perform routine preventative maintenance testing, inspections and cleaning on a more frequent basis.

Cambridge Transformer

Observations

- Oil analysis
    - Power factor exceeds IEEE limits for in service oil.
    - Oxidation inhibitor is below acceptable limit.
    - Moisture content exceeds IEEE limits.

Recommendations

- Inhibitor should be added to the unit in order to preserve general oil qualities.
- Resample unit in 6 months to better trend rate of rise.
- Consider performing electrical testing on unit.

ANNEX A: DESTROYES POWER TRANSFORMER TEST RESULTS

Destroyes Transformer

ELECTEKPOWER

Client	Northern Ontario Wires		
Execution date	2023-07-09	Reason of the job	Routine
Tested by	Gary Taylor	Location	Iroquois Falls
Approved by		Asset	Transformer
Report ID		Asset type	Two-winding
Report issue date	2023-07-26 10:56:28 AM	Asset serial number	1-2577
Work order		Manufacturer	Ferranti-Packard

Summary

Performed tests	Assessment
Overall PF & CAP	Pass
Exciting Current	Pass
Leakage Reactance H-X	Pass
TTR H-X	Pass
DC Winding Resistance H	Pass
DC Winding Resistance X	Pass
Insulation Resistance	Pass

Overall Assessment	Acceptable

Tested by:
Gary Taylor

Approved by:

Location & company information

Location	
Name	Northern Ontario Wires
Region	
Division	
Area	
Plant	
Address	287 Teefy Street
City	Iroquois Falls
State/Province	Ontario
Postal code	P0L 1C0
Country	Canada

Company	
Company	Electek Power Services
Department	
Address	12-868 Falconbridge Road
City	Sudbury
State/Province	Ontario
Postal code	P3A 5K7
Country	Canada
Phone No.	(705) 507-1329
Fax No.	
E-mail	gtaylor@electek.ca

Geo coordinates	

Contact person	
Name	Marc Belanger
Phone No. 1	(705) 232-8494
Phone No. 2	
Fax No.	
E-mail	marc.belanger@nowinc.ca

Comment

Transformer nameplate data

Serial number	1-2577	Apparatus ID	Destroyes Transformer
Manufacturer	Ferranti-Packard	Feeder	
Manufacturing year	1966	No. phases	3
Manufacturer type	ONAN	Vector group	Dyn1

Comment

Voltage ratings

Winding	Voltage L-L	Voltage L-N	Insul. level L-L
H	12.000 kV	kV	110 kV
X	4.000 kV	2.309 kV	75 kV

Power ratings

Rated power	Cooling class	Temp. rise wind.
4.000 MVA	ONAN	55

Current ratings at rated power

Winding		
H	X	Rated power
192.000 A	579.000 A	4.000 MVA

Short-circuit rating

Max. short-circuit current	kA	s

Impedances

Ref. temp.	75 °C

Leakage reactance H - X

Zk[%]	Base power	Base voltage	Load losses Pk	OLTC position	DETC position
5.000 %	4.000 MVA	12.000 kV	W	17	

Others

Category	Distribution
Status	In operation
Tank type	Sealed conservator
Insulation medium	Mineral oil
Fluid insulation volume	1370 gals
Fluid insulation weight	11760 lbs
Total weight	32530 lbs

Tap Changers nameplate data

OLTC

Serial number	
Manufacturer	Ferranti Packard
Manufacturer type	
Winding	H
Tap scheme	1...33
No. of taps	33

Tap	Voltage
1	10800.0 V
2	10875.0 V
3	10950.0 V
4	11025.0 V
5	11100.0 V
6	11175.0 V
7	11250.0 V
8	11325.0 V
9	11400.0 V
10	11475.0 V
11	11550.0 V
12	11625.0 V
13	11700.0 V
14	11775.0 V
15	11850.0 V
16	11925.0 V
17	12000.0 V
18	12075.0 V
19	12150.0 V
20	12225.0 V
21	12300.0 V
22	12375.0 V
23	12450.0 V

Tap	Voltage
24	12525.0 V
25	12600.0 V
26	12675.0 V
27	12750.0 V
28	12825.0 V
29	12900.0 V
30	12975.0 V
31	13050.0 V
32	13125.0 V
33	13200.0 V

Test set information

Model	Serial number	Calibration date
TESTRANO 600	GK813Z	2023-02-15
CP TD12	CM745F	2023-02-15

Global test conditions

Weather	Clear	Humidity	48 %
Unit location	Outside	Ambient temperature	22 °C

Overall PF & CAP

Ambient temperature	22°C	Weather	Clear
Top oil temperature	35 °C	Humidity	48%

Comments

Standard test

Block 1: injection at H

Corr. temperature	35 °C
Corr. factor	0.72

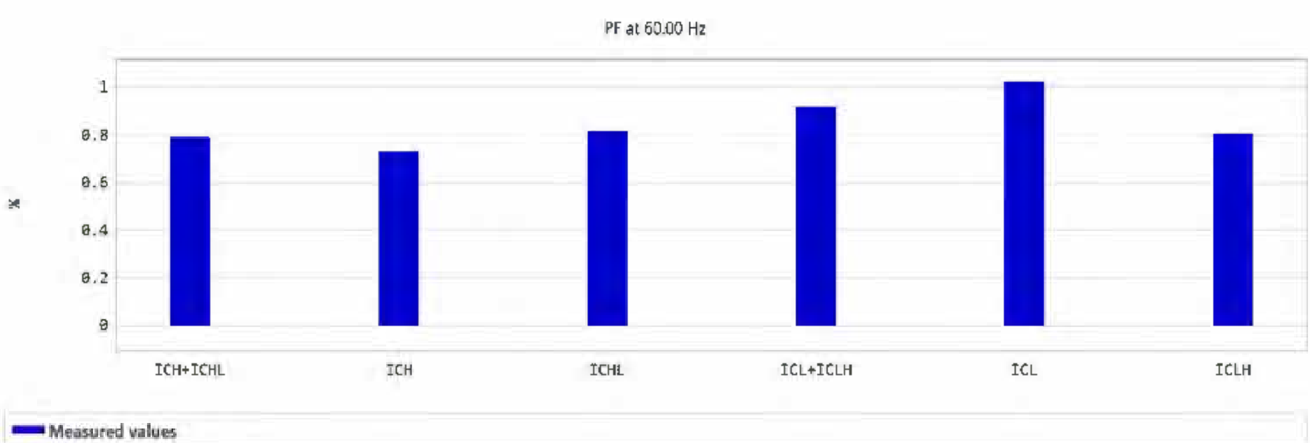
No.	Meas	Test mode	Freq.	V out	I out	Watt losses	PF meas	PF corr	Cap. meas	Assessment
1	ICH+ICHL	GST	60.00 Hz	6.00 kV	17.90 mA	1173.29 mW	1.0923 %	0.7865 %	7912.1 pF	Pass
2	ICH (V)	GSTg-A	60.00 Hz	6.00 kV	6.44 mA	390.17 mW	1.0101 %	0.7273 %	2843.3 pF	Pass
3	ICHL (V)	UST-A	60.00 Hz	6.00 kV	11.47 mA	776.61 mW	1.1288 %	0.8127 %	5069.1 pF	Pass

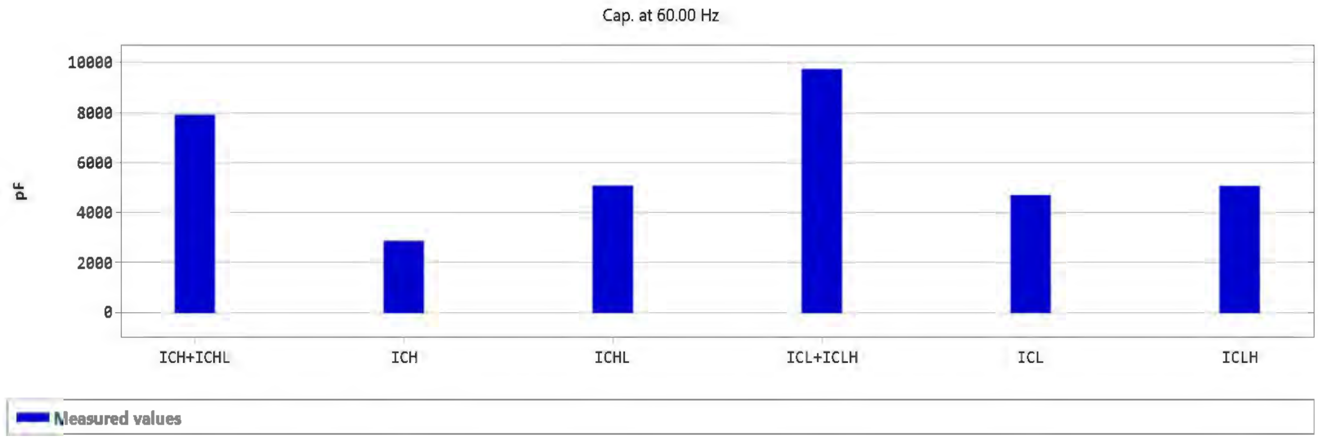
Block 2: injection at X

Corr. temperature	35 °C
Corr. factor	0.72

No.	Meas.	Test mode	Freq.	V out	I out	Watt losses	PF meas	PF corr	Cap. meas	Assessment
4	ICL+ICLH	GST	60.00 Hz	2.00 kV	7.35 mA	186.40 mW	1.2685 %	0.9133 %	9742.8 pF	Pass
5	ICL (V)	GSTg-A	60.00 Hz	2.00 kV	3.53 mA	99.86 mW	1.4150 %	1.0188 %	4876.0 pF	Pass
6	ICLH (V)	UST-A	60.00 Hz	2.00 kV	3.82 mA	85.16 mW	1.1145 %	0.8024 %	5067.6 pF	Pass

Graphs for standard test




Cap. at 60.00 Hz
pF
10000
8000
6000
4000
2000
0
ICH+ICHL
ICH
ICHL
ICL+ICLH
ICL
ICLH
Measured values

Exciting Current

Comment

Measurement settings

Test voltage	6 kV
Test frequency	60.00 Hz
Tap changer under test	OLTC

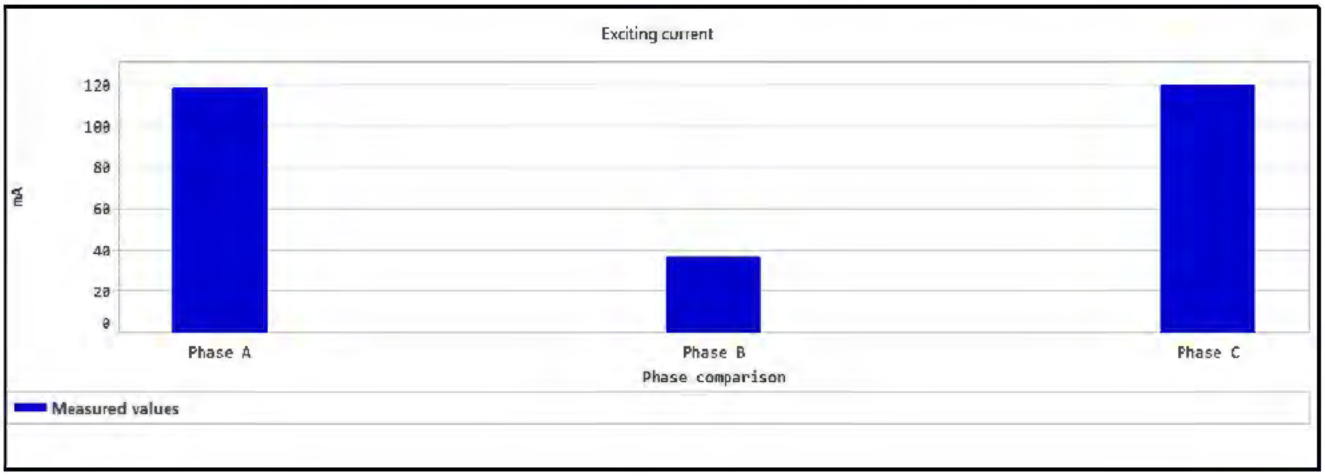
Automatic tap control	No

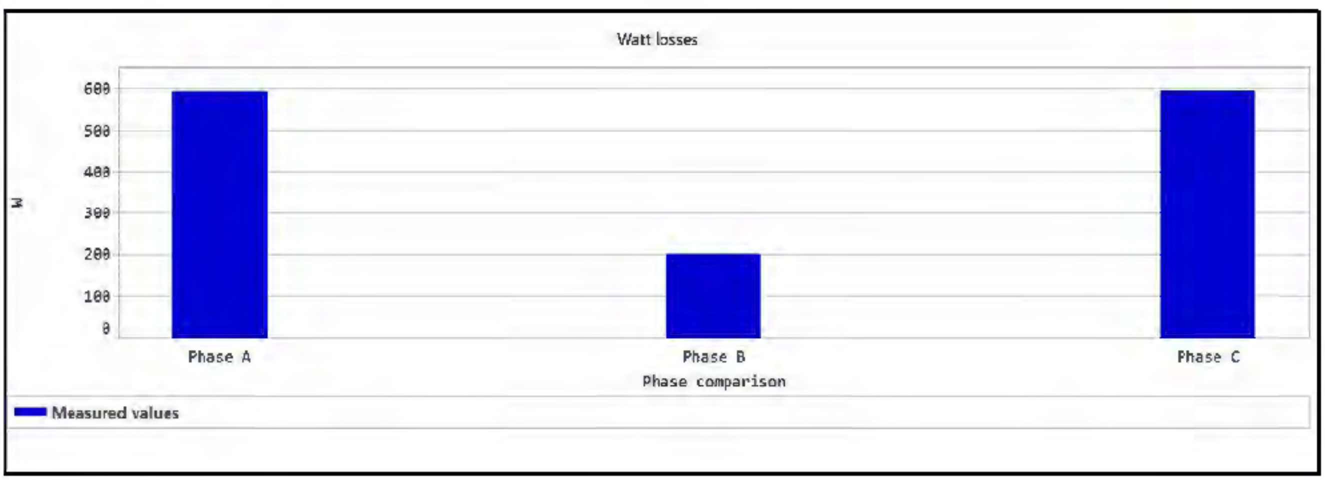
Averaging	2
Bandwidth	±20 Hz
AvoidTestFrequency	No

Use reference voltage	No

Measurements (sorted by tap)

Tap	*Phase*	*V out*	*I out*	*I phase*	*Watt losses*	*Reactance*	*Assessment*
1	A	6.00 kV	118.446 mA	-33.45 °	592.989 W	27.922 kΩ	Pass
1	B	6.00 kV	36.619 mA	-24.22 °	200.373 W	67.225 kΩ	Pass
1	C	6.00 kV	119.827 mA	-34.21 °	594.537 W	28.147 kΩ	Pass





Leakage Reactance H-X

Comment

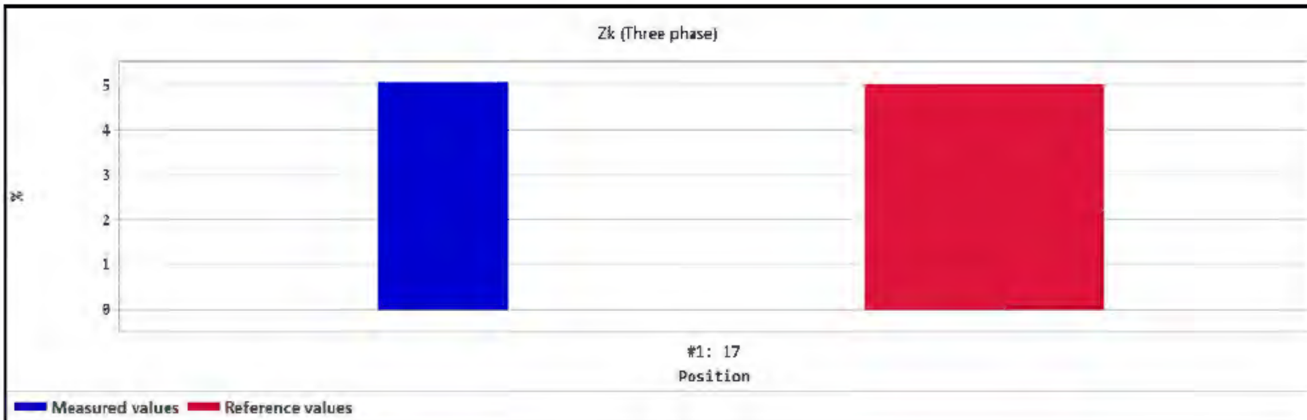
Measurement settings

Auto shorting	Enabled	Winding temperature	20 °C
Current limit	33.00 A	Reference temperature	75 °C
Default frequency	60.00 Hz	Temperature correction factor (K)	1
Winding material	Copper		

Result table for three phase test

Position	*Phase*	*Rk**	*Xk**	*Zk**	*Zk calc**	*Zk dev*	*Assessment*
#1: 17	A	211.613 mΩ	1.840 Ω	1.852 Ω	5.04 %	0.71 %	Pass
	B	133.232 mΩ	1.745 Ω	1.750 Ω			
	C	194.360 mΩ	1.826 Ω	1.836 Ω			

Graphs for three phase test



TTR H-X

Comment

Measurement settings

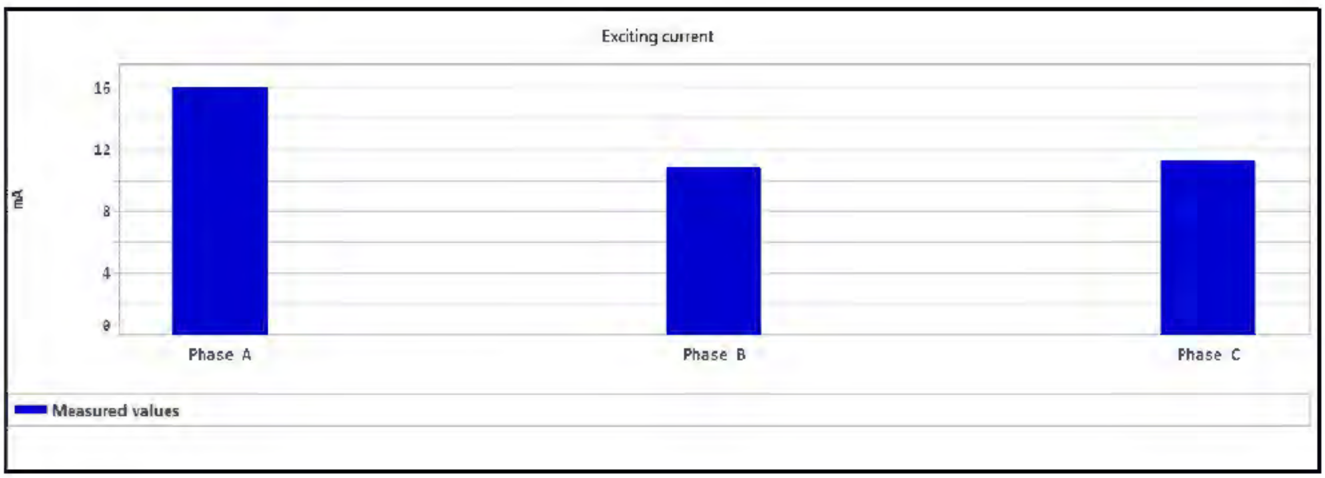
Test voltage	120 V
Test frequency	60.00 Hz
Tap changer under test	OLTC

Automatic tap control	No
Ratio	TTR*

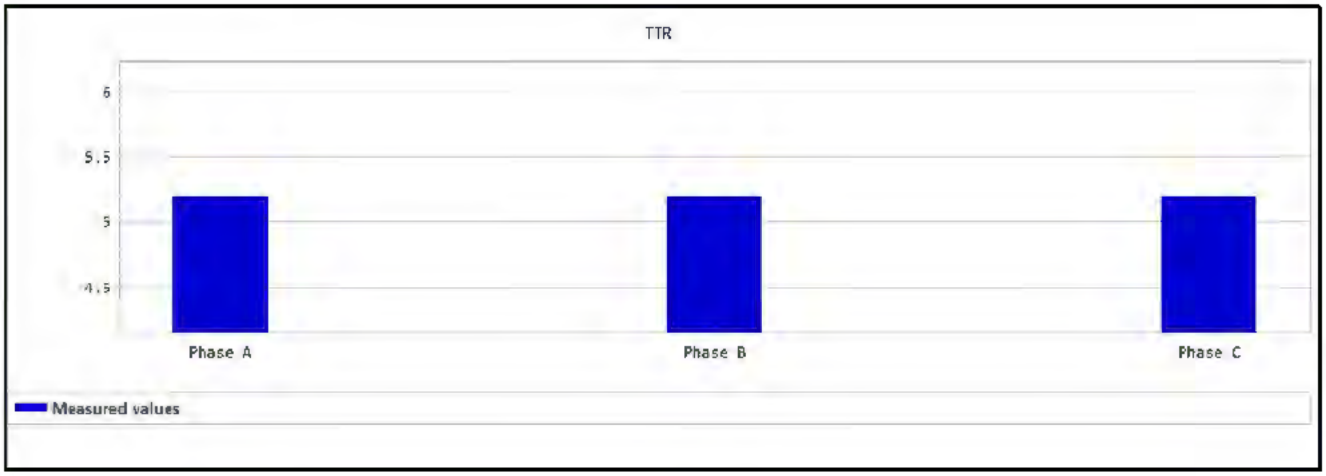
Measurements (sorted by tap)

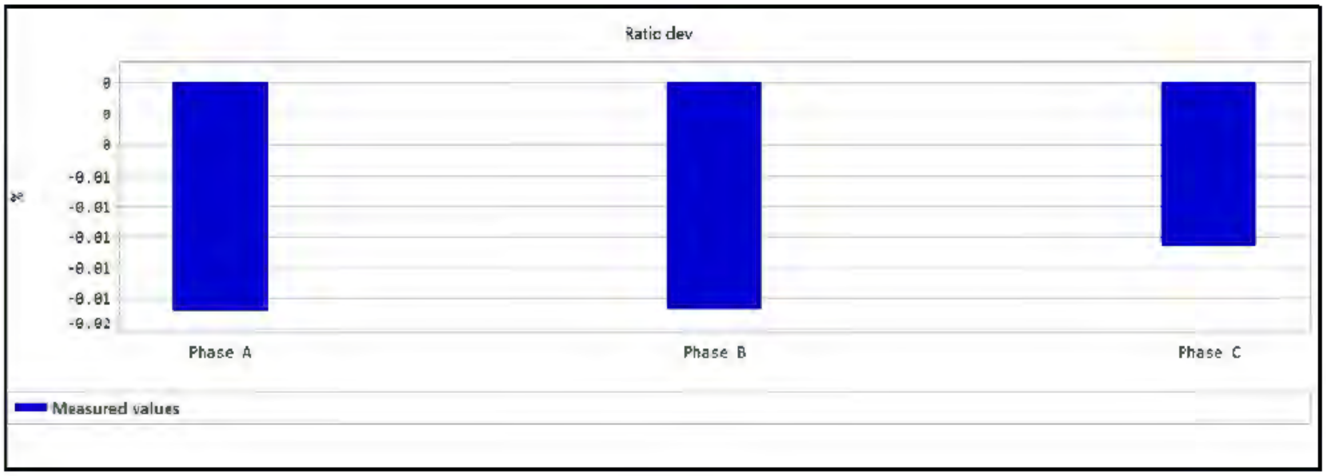
Tap	*Phase*	*Nom. Ratio*	*V prim (L-L)*	*I prim*	*V sec (L-L)*	*V phase*	*TTR**	*Ratio dev*	*Assessment*
17	A	5.1962	119.92 V	15.973 mA	39.98 V	30 °	5.1954	-0.01 %	Pass
17	B	5.1962	119.92 V	10.788 mA	39.98 V	30.01 °	5.1954	-0.01 %	Pass
17	C	5.1962	119.92 V	11.249 mA	39.98 V	30 °	5.1956	-0.01 %	Pass

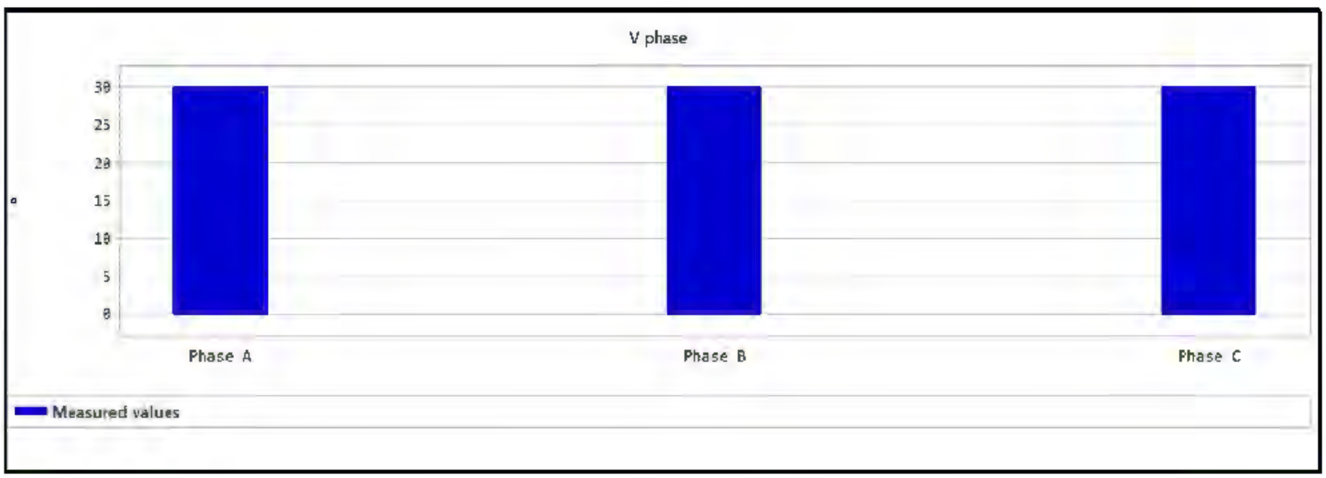
Graph for exciting current



Graphs for standard test







DC Winding Resistance H

Comment

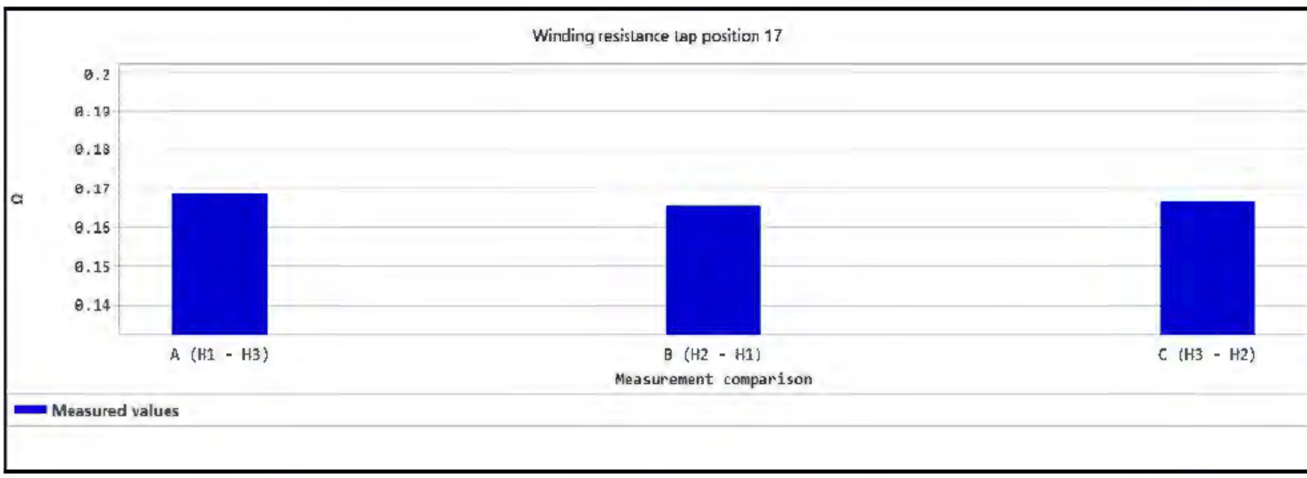
Measurement settings

Test current	5 A	Tap changer under test	OLTC
Output mode	16 A @ 340 V	Automatic tap control	No
	1 ph.		

Automatic result	True
Settling time (At)	5 s
Tolerance R dev	0.01 %
Recording time	200.0 ms

	A (H1 - H3)			*B (H2 - H1)*			*C (H3 - H2)*		
Tap	*R meas*	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*
17	168.466 mΩ	0.007 %	168.466 mΩ	165.566 mΩ	0.003 %	165.566 mΩ	166.613 mΩ	0.001 %	166.613 mΩ

Graphs for standard test



DC Winding Resistance X

Comment

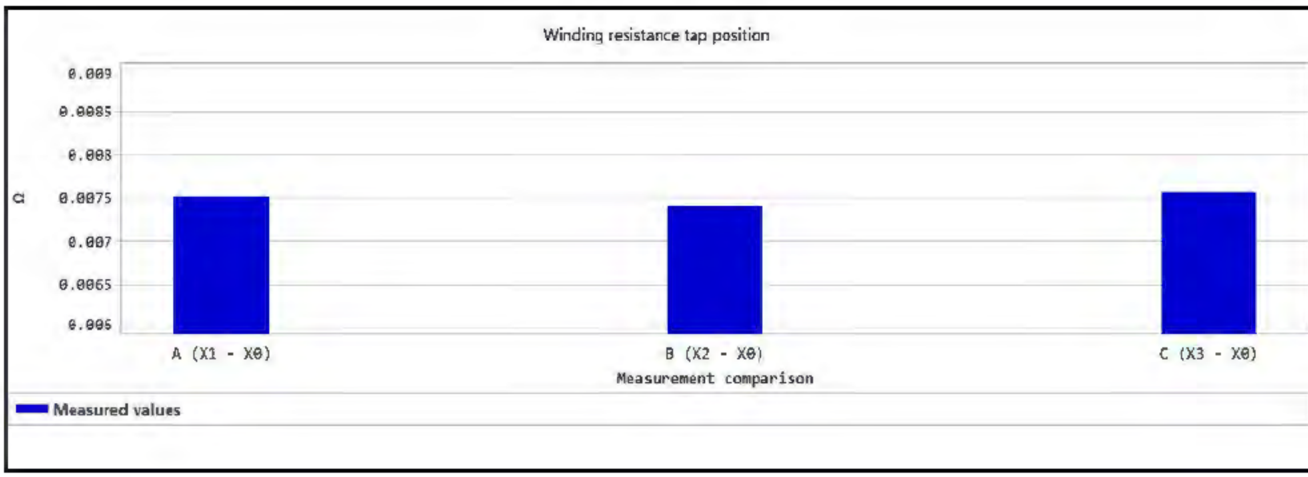
Measurement settings

Test current	5 A
Output mode	16 A @ 340 V
	1 ph.

Automatic result	True
Settling time (At)	5 s
Tolerance R dev	0.03 %
Recording time	200.0 ms

A (X1 - X0)			*B (X2 - X0)*			*C (X3 - X0)*		
R meas	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*
7.510 mΩ	0.010 %	7.510 mΩ	7.407 mΩ	0.017 %	7.407 mΩ	7.562 mΩ	0.024 %	7.562 mΩ

Graphs for standard test



Insulation Resistance

Comment

Test object temperature	35 °C
Reference temperature	20 °C

Ambient temperature	22 °C
Humidity	48 %

Name **High - Low/Ground**

Time	R meas	R corr	V DC	I DC
60 s	1.367 GΩ	3.827 GΩ	1.00 kV	731.529 nA

Name **Low - High/Ground**

Time	R meas	R corr	V DC	I DC
60 s	2.048 GΩ	5.734 GΩ	1.00 kV	488.281 nA

Name **High/Low - Ground**

Time	R meas	R corr	V DC	I DC
60 s	1.597 GΩ	4.471 GΩ	1.00 kV	626.174 nA

SDMyers INTELLIGENT TRANSFORMER MANAGEMENT

Date Printed 8/15/2023 **TC# 9002**

Customer	6000885 Electek-Nother Ontario Wires	**City**	Sarnia, ON	**Location**	OUTDOOR
Sub-Name	DETROYES	**Unit No.**		**Other**	

NAMEPLATE DATA

Manufacturer	FERRANTI		**Equipment Type**	TRANSFORMER
Manufacture Date	1/1/1966		**Transformer Class**	
Serial No.	1-2577		**Impedance %**	5.00
KVA Rating	4,000		**Phase/Cycle**	3/60
High Voltage	12,000	D	**Liquid Type**	OIL
Low Voltage	2,300	Y	**Gallons**	1,370
Weight	32,529.8		**Other Access**	

ADDITIONAL EQUIPMENT

Radiators	Yes	**Conservator Tank**	
Fans	No	**LTC Compartment**	
Water Cooled		**Bushing Location**	SIDE ENCL.
Oil Pumps	No	**Breather**	
Top FPV (inch)	0	**Hose Length (feet)**	
Bottom FPV (inch)	0	**Service Online**	
InsulationType	55C	**Power Available**	

VISUAL INSPECTION

DATE	LEVEL	SAMPLE TEMP	TOP TEMP	P/V	PAINT	LEAKS
07/09/23	NORMAL	25	29		GOOD	NONE

FIELD SERVICE

DATE	SERVICE

Additional Information

Reason Not Tested

LIQUID SCREEN TEST DATA

DATE	SERVICE	ACID	IFT	DIEL 877	DIEL 1816	GAP	COLOR		SP. GRAV.	VISUAL	SEDIMENT
07/09/23		0.020 AC	40.0 AC	52 AC			0.50	AC	0.852 AC	CLEAR AC	NONE AC

INHIBITOR CONTENT

DATE	PCT. BY WEIGHT
07/09/23	<0.02% UN

NOTE - STUDIES SHOW THAT A LEVEL OF 0.3% INHIBITOR IS OPTIMUM FOR PRESERVATION OF IN-SERVICE TRANSFORMER OILS. OILS WITH A LEVEL BELOW 0.08% ARE CONSIDERED TO BE UNINHIBITED.

LIQUID POWER FACTOR

DATE	25 C	100 C
07/09/23	0.009 AC	0.431 AC

KEY TO ABBREVIATIONS: AC - ACCEPTABLE QU - QUESTIONABLE UN - UNACCEPTABLE RS - RESAMPLE

NOTE: * After a result indicates that the test or service was performed by an outside source.

Customer	6000885 Electek-Nother Ontario Wires	S/N	1-2577				
Sub-Name	DETROYES	Mfg.	FERRANTI	Gallons	1,370	High Volt.	12,000
Location	OUTDOOR	Unit No.		KVA	4,000	Low Volt.	2,300

KARL FISCHER TESTING MOISTURE CONTENT EXPRESSED IN PPM

DATE	AVG. TEMP	PPM	PCT. SATURATION		MOISTURE BY DRY WEIGHT PCT.
07/09/23	30	26	30 8	UN	3 32

RECOMMENDATION RETEST 3 MONTHS
The moisture content is unacceptable based on the equipment class and liquid type. A shorter test interval is recommended to monitor this unit

FURAN ANALYSIS EXPRESSED IN PPB

DATE	5H2F	2FOL	2FAL	2ACF	5M2F	TOTAL
07/09/23	ND	ND	ND	ND	ND	ND

RECOMMENDATION RETEST 1 YEAR
THESE BASELINE DATA INDICATE THE CELLULOSIC INSULATION IS IN GOOD CONDITION.

CALCULATED DP 800 **EST. LIFE REMAINING** 100%

GAS-IN-OIL ANALYSIS GAS CHROMATOGRAPHY EXPRESSED IN PPM

DATE	HYDROGEN	OXYGEN	NITROGEN	METHANE	CARBON MONOXIDE	CARBON DIOXIDE	ETHANE	ETHYLENE	ACETYLENE	TOTAL COMBUST.	TOTAL GAS
07/09/23	ND	28,600	50,500	ND	36	800	ND	2	ND	38	79,938

RECOMMENDATION RETEST 1 YEAR
A-THE ANALYSIS OF THIS SAMPLE SHOWS ONLY MINOR AMOUNTS OF COMBUSTIBLE GAS. THIS BASELINE INDICATES NORMAL OPERATION.

ICP METALS-IN-OIL EXPRESSED IN PPM

DATE	ALUMINUM	IRON	COPPER
07/09/23	<0.1	<0.03	<0.01

RECOMMENDATION RETEST 1 YEAR
THERE ARE NO DIAGNOSTIC LEVELS OF METALS IN THIS SAMPLE.
THESE DATA CAN SERVE AS A BASELINE FOR FUTURE ANALYSES.

PCB CONTENT EXPRESSED IN PPM

DATE	1242	1254	1260	OTHER	TOTAL

NOTE: * After a result indicates that the test or service was performed by an outside source.

ANNEX B: DESTROYES SWITCHGEAR TEST RESULTS

ELECTEKPOWER

SWITCHGEAR BUS RESISTANCE

Customer:	Northern Ontario Wires	Customer P.O. #:	3301	Job #:	23068448
Tested by:	GT / SC	Date:	July 9, 2023	Manufacturer:	S&C
Location:	Detroyes	Ambient Temp.:	33°C	Humidity:	27%

CONTACT RESISTANCE

DESIGNATION	CELL	PHASE	μΩ
Transformer secondary bus connection	F1-1 Switch Line Side	A	113.9
		B	115.9
		C	121.0
Transformer secondary bus connection	F1-2 Switch Line Side	A	184.0
		B	183.0
		C	189.5
Transformer secondary bus connection	F1-3 Switch Line Side	A	263.6
		B	248.6
		C	270.7

Test Equipment Used: ES001 @ 200A

INSULATION RESISTANCE TEST IN OHMS

	Phase to Phase	Phase to Ground	Line to Load
Phase A	140.1 GΩ	60.6 GΩ	
Phase B	154.5 GΩ	70.7 GΩ	
Phase C	135.2 GΩ	70.9 GΩ	
Test Voltage:	5 kV		

Test Equipment Used: ES005

COMMENTS:
Insulation resistance results include all feeder switches closed with fuses removed.

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Norther Ontario Wires	Customer P.O. #:	3301	Job #:	23068456
Tested by:	GT / SC	Date:	July 13, 2023	Cat #:	34560
Location:	Detroyes	Position:	F1-1	Manufacturer:	S&C
Rated Voltage:	5kV	Close Voltage:	Manual	Type:	
Rated Current:	600A	Open Voltage:	Manual	Year Built:	
Frequency:	60hZ	Motor Voltage:	Manual	Model:	
Interrupt Current:	40kA	Motor Mech. Type:	N/A	Instruction manual:	
Ambient Temp.:	33°C	Weather Cond.:	Cloudy	Humidity:	27%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X			X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers	X			X			X		
18. Cleaned fuses	X			X			X		
19. Condition of fuses	X			X			X		
20. Verify correct fuse size	X			X			X		
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened	X		
28. Latch mechanism	X		
29. Key interlocks	X		
30. Operating chain	X		
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater	X		
40. Screen/window cond'n	X		
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST IN OHMS

	Switch	Fuses
Phase A	76.0 µΩ	335.9 µΩ
Phase B	79.0 µΩ	273.1 µΩ
Phase C	72.7 µΩ	248.8 µΩ
Test Current:	10A	

Test Equipment Used: ES007

INSULATION RESISTANCE TEST IN OHMS

	Phase to Phase	Phase to Ground	Line to Load
Phase A			587 GΩ
Phase B			1.025 TΩ
Phase C			921 GΩ
Test Voltage:	5 kV		

Test Equipment Used: ES004

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Norther Ontario Wires	Customer P.O. #:	3301	Job #:	23068456
Tested by:	GT / SC	Date:	July 13, 2023	Cat #:	34560
Location:	Detroyes	Position:	F1-2	Manufacturer:	S&C
Rated Voltage:	5kV	Close Voltage:	Manual	Type:	
Rated Current:	600A	Open Voltage:	Manual	Year Built:	
Frequency:	60hZ	Motor Voltage:	Manual	Model:	
Interrupt Current:	40kA	Motor Mech. Type:	N/A	Instruction manual:	
Ambient Temp.:	33°C	Weather Cond.:	Cloudy	Humidity:	27%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X			X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers	X			X			X		
18. Cleaned fuses	X			X			X		
19. Condition of fuses	X			X			X		
20. Verify correct fuse size	X			X			X		
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened	X		
28. Latch mechanism	X		
29. Key interlocks	X		
30. Operating chain	X		
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater	X		
40. Screen/window cond'n	X		
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST IN OHMS

	Switch	Fuses
Phase A	75.8 μΩ	401.8 μΩ
Phase B	78.5 μΩ	375.3 μΩ
Phase C	81.0 μΩ	234.7 μΩ
Test Current:	10A	

Test Equipment Used: ES007

INSULATION RESISTANCE TEST IN OHMS

	Phase to Phase	Phase to Ground	Line to Load
Phase A			1.146 TΩ
Phase B			1.349 TΩ
Phase C			1.165 TΩ
Test Voltage:	5 kV		

Test Equipment Used: ES004

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

Fuses:

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Norther Ontario Wires	Customer P.O. #:	3301	Job #:	23068456
Tested by:	GT / SC	Date:	July 13, 2023	Cat #:	34560
Location:	Detroyes	Position:	F1-3	Manufacturer:	S&C
Rated Voltage:	5kV	Close Voltage:	Manual	Type:	
Rated Current:	600A	Open Voltage:	Manual	Year Built:	
Frequency:	60hZ	Motor Voltage:	Manual	Model:	
Interrupt Current:	40kA	Motor Mech. Type:	N/A	Instruction manual:	
Ambient Temp.:	33°C	Weather Cond.:	Cloudy	Humidity:	27%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X			X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers	X			X			X		
18. Cleaned fuses	X			X			X		
19. Condition of fuses	X			X			X		
20. Verify correct fuse size	X			X			X		
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened	X		
28. Latch mechanism	X		
29. Key interlocks	X		
30. Operating chain	X		
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater	X		
40. Screen/window cond'n	X		
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST IN OHMS

	Switch	Fuses
Phase A	77.7 μΩ	353.1 μΩ
Phase B	74.1 μΩ	369.3 μΩ
Phase C	75.1 μΩ	341.7 μΩ
Test Current:	10A	

Test Equipment Used: ES007

INSULATION RESISTANCE TEST IN OHMS

	Phase to Phase	Phase to Ground	Line to Load
Phase A			320.3 GΩ
Phase B			433 GΩ
Phase C			801 GΩ
Test Voltage:	5 kV		

Test Equipment Used: ES004

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

Fuses:

ANNEX C: MILL POWER TRANSFORMER TEST RESULTS

Mill Gate Transformer

ELECTEKPOWER

Client	Northern Ontario Wires		
Execution date	2023-07-09	Reason of the job	Routine
Tested by	Andrew Mckinnon	Location	Iroquois Falls
Approved by		Asset	Mill Gate Transformer
Report ID		Asset type	Two-winding
Report issue date	2023-07-26 11:41:09 AM	Asset serial number	261784
Work order		Manufacturer	Ferranti Electric

Summary

Performed tests	Assessment
Overall PF & CAP	Investigate
Leakage Reactance H-X	Pass
TTR H-X	Pass
DC Winding Resistance H	Pass
DC Winding Resistance X	Investigate
Insulation Resistance	Pass

Overall Assessment	Investigate

Tested by:
Andrew Mckinnon

Approved by:

Location & company information

Location	
Name	Northern Ontario Wires
Region	
Division	
Area	
Plant	
Address	287 Teefy Street
City	Iroquois Falls
State/Province	Ontario
Postal code	P0L 1C0
Country	Canada

Company	
Company	Electek Power Services
Department	
Address	12-868 Falconbridge Road
City	Sudbury
State/Province	Ontario
Postal code	P3A 5K7
Country	Canada
Phone No.	(705) 507-1329
Fax No.	
E-mail	gtaylor@electek.ca

Geo coordinates	

Contact person	
Name	Marc Belanger
Phone No. 1	(705) 232-8494
Phone No. 2	
Fax No.	
E-mail	marc.belanger@nowinc.ca

Comment

Transformer nameplate data

Serial number	261784
Manufacturer	Ferranti
Manufacturing year	1960
Manufacturer type	ONS

Apparatus ID	Mill Gate Transformer
Feeder	
No. phases	3
Vector group	Dyn11

Comment

Voltage ratings

Winding	Voltage L-L	Voltage L-N	Insul. level L-L
H	12.000 kV	kV	95 kV
X	3.984 kV	2.300 kV	75 kV

Power ratings

Rated power	Cooling class	Temp. rise wind.
2.000 MVA	ONAN	55

Current ratings at rated power

Winding		
H	X	Rated power
A	A	2.000 MVA

Short-circuit rating

Max. short-circuit current	kA	s

Impedances

Ref. temp.	75 °C

Leakage reactance H - X

Zk[%]	Base power	Base voltage	Load losses Pk	OLTC position	DETC position
5.18%	2 MVA	12 kV	W		

Others

Category	Distribution
Status	In operation
Tank type	Sealed conservator
Insulation medium	Mineral oil
Fluid insulation volume	375 gals
Fluid insulation weight	lbs
Total weight	72973 lbs

Test set information

Model	Serial number	Calibration date
TESTRANO 600	GK813Z	2023-02-18
CP TD12	CM745F	2023-02-18

Global test conditions

Weather	Clear	Humidity	27 %
Unit location	Outside	Ambient temperature	33 °C

Overall PF & CAP

Ambient temperature	33 °C		Weather	Clear
Top oil temperature	30 °C		Humidity	27 %

Comments

Standard test

Block 1: injection at H

Corr. temperature	20 °C
Corr. factor	1

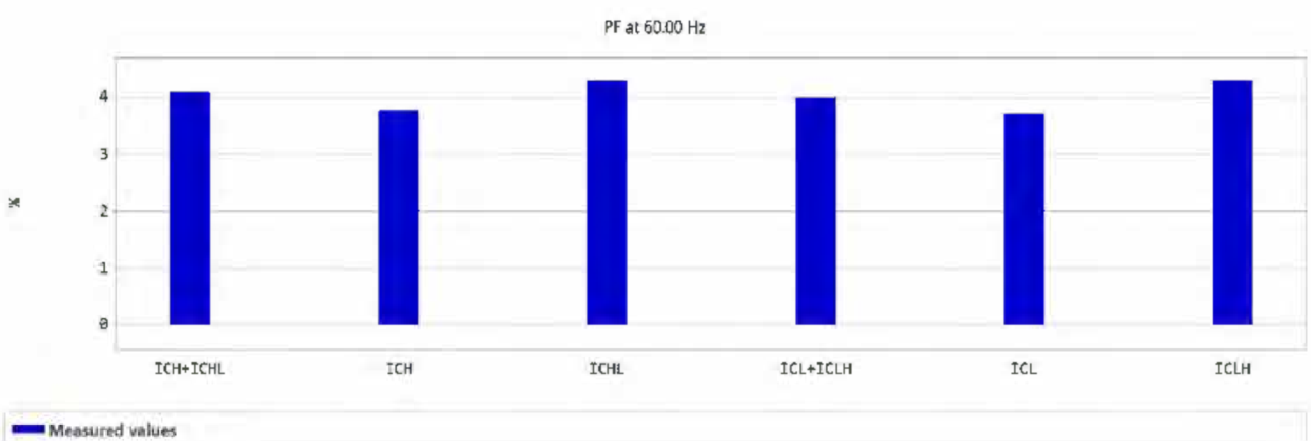
No.	Meas	Test mode	Freq.	V out	I out	Watt losses	PF meas	PF corr	Cap. meas	Assessment
1	ICH+ICHL	GST	60.00 Hz	6.00 kV	15.19 mA	3715.66 mW	4.0775 %	4.0775 %	6706.2 pF	Investigate
2	ICH (V)	GSTg-A	60.00 Hz	6.00 kV	6.27 mA	1410.11 mW	3.7500 %	3.7500 %	2765.9 pF	Investigate
3	ICHL (V)	UST-A	60.00 Hz	6.00 kV	8.93 mA	2288.65 mW	4.2726 %	4.2726 %	3944.0 pF	Investigate

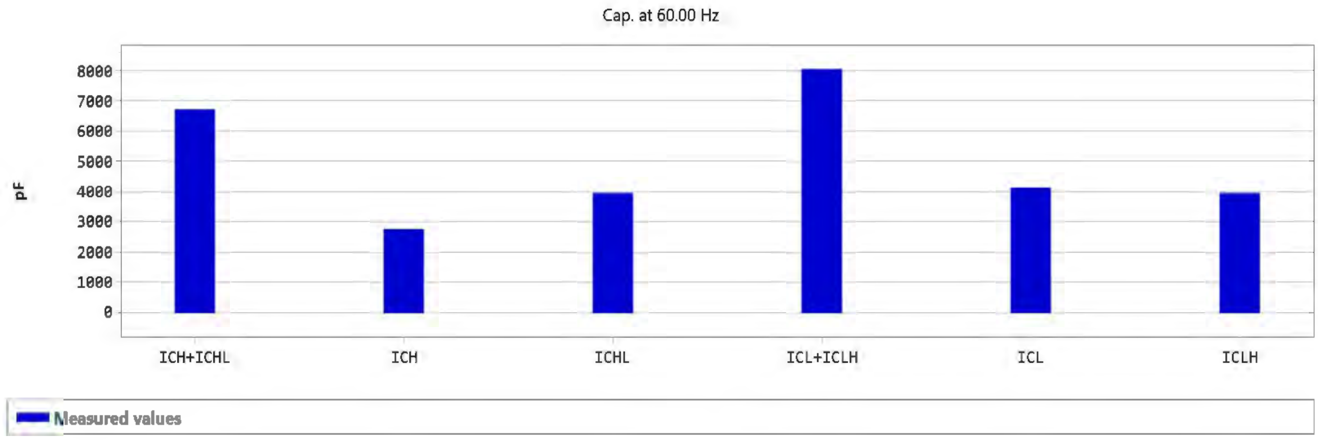
Block 2: injection at X

Corr. temperature	20 °C
Corr. factor	1

No.	Meas.	Test mode	Freq.	V out	I out	Watt losses	PF meas	PF corr	Cap. meas	Assessment
4	ICL+ICLH	GST	60.00 Hz	2.00 kV	6.07 mA	482.82 mW	3.9747 %	3.9747 %	8048.2 pF	Investigate
5	ICL (V)	GSTg-A	60.00 Hz	2.00 kV	3.10 mA	228.72 mW	3.6893 %	3.6893 %	4106.0 pF	Investigate
6	ICLH (V)	UST-A	60.00 Hz	2.00 kV	2.97 mA	254.36 mW	4.2757 %	4.2757 %	3942.1 pF	Investigate

Graphs for standard test




Cap. at 60.00 Hz
pF
8000
7000
6000
5000
4000
3000
2000
1000
0
ICH+ICHL
ICH
ICHL
ICL+ICLH
ICL
ICLH
Measured values

Leakage Reactance H-X

Comment

Measurement settings

Auto shorting	Enabled	Winding temperature	20 °C
Current limit	33.00 A	Reference temperature	75 °C
Default frequency	60.00 Hz	Temperature correction factor (K)	1.22
Winding material	Copper		

Result table for three phase test

Position	*Phase*	*Rk**	*Xk**	*Zk**	*Zk calc**	*Zk dev*	*Assessment*
#1	A	578.911 mΩ	3.636 Ω	3.681 Ω	5.07 %	-2.04%	Pass
	B	517.938 mΩ	3.634 Ω	3.670 Ω			
	C	520.148 mΩ	3.571 Ω	3.608 Ω			

TTR H-X

Comment

Measurement settings

Test voltage	120 V
Test frequency	60.00 Hz
Tap changer under test	DETC

Ratio	TTR*

Measurements (sorted by tap)

Tap	*Phase*	*Nom. Ratio*	*V prim (L-L)*	*I prim*	*V sec (L-L)*	*V phase*	*TTR**	*Ratio dev*	*Assessment*
1	A	5.2170	119.90 V	37.989 mA	39.70 V	30.01 °	5.2309	0.09 %	Pass
1	B	5.2170	119.90 V	28.418 mA	39.70 V	30.01 °	5.2309	0.09 %	Pass
1	C	5.2170	119.90 V	27.824 mA	39.70 V	30 °	5.2310	0.09 %	Pass

DC Winding Resistance H

Comment

Measurement settings

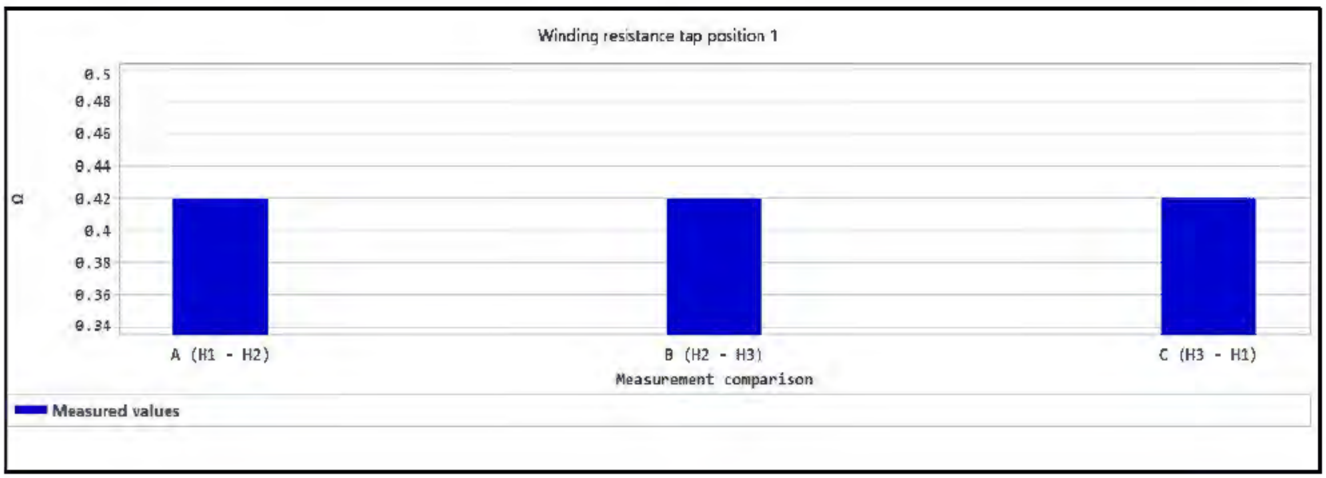
Test current	5 A
Output mode	16 A @ 340 V
	1 ph.

Tap changer under test	DETC

Automatic result	True
Settling time (At)	5 s
Tolerance R dev	0.01 %
Recording time	200.0 ms

	A (H1 - H2)			*B (H2 - H3)*			*C (H3 - H1)*		
Tap	*R meas*	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*
1	419.300 mΩ	0.004 %	419.300 mΩ	419.581 mΩ	0.004 %	419.581 mΩ	419.801 mΩ	0.002 %	419.801 mΩ

Graphs for standard test



DC Winding Resistance X

Comment

Measurement settings

Test current	5 A
Output mode	16 A @ 113 V
	3 ph.
Measurement	L-N

Winding temperature	20 °C
Reference temperature	°C
Temp. corr. factor (K)	

Automatic result	True
Settling time (At)	5 s
Tolerance R dev	0.01 %
Recording time	200.0 ms

A (X1 - X0)			*B (X2 - X0)*			*C (X3 - X0)*		
R meas	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*
18.558 mΩ	0.002 %	18.558 mΩ	32.874 mΩ	0.003 %	32.874 mΩ	26.227 mΩ	0.003 %	26.227 mΩ

Insulation Resistance

Comment

Test object temperature	30°C	Ambient temperature	33 °C
Reference temperature	20 °C	Humidity	27 %

Name	High - Low/Ground

Time	R meas	R corr	V DC	I DC
60 s	964 MΩ	1.908 GΩ	1.00 kV	1.037 µA

Name	Low - High/Ground

Time	R meas	R corr	V DC	I DC
60 s	523 MΩ	1.035 GΩ	1.00 kV	1.912 µA

Name	High/Low - Ground

Time	R meas	R corr	V DC	I DC
60 s	800 MΩ	1.584 GΩ	1.00 kV	1.250 µA

SDMyers INTELLIGENT TRANSFORMER MANAGEMENT

Date Printed 8/15/2023

TC# 9001

Customer	6000885 Electek-Nother Ontario Wires	**City**	Sarnia, ON	**Location**	
Sub-Name	MILL	**Unit No.**	T1	**Other**	

NAMEPLATE DATA

Manufacturer	FERRANTI		**Equipment Type**	TRANSFORMER
Manufacture Date			**Transformer Class**	ONAN
Serial No.	261784		**Impedance %**	5.18
KVA Rating	2,000		**Phase/Cycle**	1/60
High Voltage	12,000	D	**Liquid Type**	OIL
Low Voltage	2,300	Y	**Gallons**	1,420
Weight	33,099.7		**Other Access**	

ADDITIONAL EQUIPMENT

Radiators	Yes	**Conservator Tank**	
Fans	No	**LTC Compartment**	Yes
Water Cooled	No	**Bushing Location**	SIDE ENCL.
Oil Pumps	No	**Breather**	
Top FPV (inch)	0	**Hose Length (feet)**	
Bottom FPV (inch)	0	**Service Online**	
InsulationType	55C	**Power Available**	

VISUAL INSPECTION

DATE	LEVEL	SAMPLE TEMP	TOP TEMP	P/V	PAINT	LEAKS
07/09/23	NORMAL	16	30		FAIR	YES - NO INFO GIVEN

FIELD SERVICE

DATE	SERVICE

Additional Information

Reason Not Tested

LIQUID SCREEN TEST DATA

DATE	SERVICE	ACID	IFT	DIEL 877	DIEL 1816	GAP	COLOR		SP. GRAV.	VISUAL	SEDIMENT
07/09/23		0.060 QU	33.0 AC	55 AC			1.50	AC	0.865 AC	CLEAR AC	NONE AC

INHIBITOR CONTENT

DATE	PCT. BY WEIGHT
07/09/23	0.03% UN

NOTE - STUDIES SHOW THAT A LEVEL OF 0.3% INHIBITOR IS OPTIMUM FOR PRESERVATION OF IN-SERVICE TRANSFORMER OILS. OILS WITH A LEVEL BELOW 0.08% ARE CONSIDERED TO BE UNINHIBITED.

LIQUID POWER FACTOR

DATE	25 C	100 C
07/09/23	0.035 AC	1.440 AC

KEY TO ABBREVIATIONS: AC - ACCEPTABLE QU - QUESTIONABLE UN - UNACCEPTABLE RS - RESAMPLE

NOTE: * After a result indicates that the test or service was performed by an outside source.

Customer	6000885 Electek-Nother Ontario Wires	S/N	261784				
Sub-Name	MILL	Mfg.	FERRANTI	Gallons	1,420	High Volt.	12,000
Location		Unit No.	T1	KVA	2,000	Low Volt.	2,300

KARL FISCHER TESTING MOISTURE CONTENT EXPRESSED IN PPM

DATE	AVG. TEMP	PPM	PCT. SATURATION		MOISTURE BY DRY WEIGHT PCT.
07/09/23	21	59	102.6	UN	12.10

RECOMMENDATION RETEST 3 MONTHS
The moisture content is unacceptable based on the equipment class and liquid type. A shorter test interval is recommended to monitor this unit.

FURAN ANALYSIS EXPRESSED IN PPB

DATE	5H2F	2FOL	2FAL	2ACF	5M2F	TOTAL
07/09/23	ND	ND	200	ND	ND	200

RECOMMENDATION RETEST 6 MONTHS
THESE BASELINE DATA INDICATE THE CELLULOSIC INSULATION IS IN GOOD CONDITION.

CALCULATED DP 650 **EST. LIFE REMAINING** 85%

GAS-IN-OIL ANALYSIS GAS CHROMATOGRAPHY EXPRESSED IN PPM

DATE	HYDROGEN	OXYGEN	NITROGEN	METHANE	CARBON MONOXIDE	CARBON DIOXIDE	ETHANE	ETHYLENE	ACETYLENE	TOTAL COMBUST.	TOTAL GAS
07/09/23	12	23,300	51,500	2	152	2,170	ND	9	ND	175	77,145

RECOMMENDATION RETEST 1 YEAR
A-THE ANALYSIS OF THIS SAMPLE SHOWS ONLY MINOR AMOUNTS OF COMBUSTIBLE GAS. THIS BASELINE INDICATES NORMAL OPERATION.

ICP METALS-IN-OIL EXPRESSED IN PPM

DATE	ALUMINUM	IRON	COPPER
07/09/23	<0.1	<0.03	0.06

RECOMMENDATION RETEST 1 YEAR
THERE ARE NO DIAGNOSTIC LEVELS OF METALS IN THIS SAMPLE. THESE DATA CAN SERVE AS A BASELINE FOR FUTURE ANALYSES.

PCB CONTENT EXPRESSED IN PPM

DATE	1242	1254	1260	OTHER	TOTAL

NOTE: * After a result indicates that the test or service was performed by an outside source.

ANNEX D: MILL SWITCHGEAR TEST RESULTS

ELECTEKPOWER

SWITCHGEAR BUS RESISTANCE

Customer:	Northern Ontario Wires	Customer P.O. #:	3301	Job #:	23068448
Tested by:	AM / MJ	Date:	July 9, 2023	Manufacturer:	S&C
Location:	Mill Substation	Ambient Temp.:	33°C	Humidity:	27%

CONTACT RESISTANCE

DESIGNATION	CELL	PHASE	μΩ
Transformer secondary bus connection	SW1 Switch Line Side	A	197.1
		B	180.6
		C	206.0
Transformer secondary bus connection	"Upper Town" SW2 Switch Line Side	A	250.3
		B	205.1
		C	255.3
Transformer secondary bus connection	"Lower Town" SW3 Switch Line Side	A	300.2
		B	257.7
		C	312.0

Test Equipment Used: ES001 @ 200A

INSULATION RESISTANCE TEST IN OHMS

	Phase to Phase	Phase to Ground	Line to Load
Phase A	2.027 GΩ	563 MΩ	
Phase B	2.875 GΩ	1.076 GΩ	
Phase C	2.239 GΩ	1.519 GΩ	
Test Voltage:	5 kV		

Test Equipment Used: ES005

COMMENTS:

Insulation resistance results include all switches closed with fuses removed.

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Norther Ontario Wires	Customer P.O. #:	3301	Job #:	23068456
Tested by:	MJ	Date:	July 13, 2023	Cat #:	34530
Location:	Mill	Position:	SW1	Manufacturer:	S&C
Rated Voltage:	5.5 kV	Close Voltage:	Manual	Type:	
Rated Current:	400 A	Open Voltage:	Manual	Year Built:	
Frequency:	60 Hz	Motor Voltage:	Manual	Model:	
Interrupt Current:		Motor Mech. Type:	N/A	Instruction manual:	
Ambient Temp.:	33°C	Weather Cond.:	Cloudy	Humidity:	27%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X			X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers	X			X			X		
18. Cleaned fuses			X			X			X
19. Condition of fuses			X			X			X
20. Verify correct fuse size			X			X			X
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened	X		
28. Latch mechanism	X		
29. Key interlocks	X		
30. Operating chain	X		
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater	X		
40. Screen/window cond'n	X		
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST IN OHMS

	Switch	Fuses
Phase A	95 μΩ	N/A
Phase B	85 μΩ	N/A
Phase C	105 μΩ	N/A
Test Current:	10A	

Test Equipment Used: ES008

INSULATION RESISTANCE TEST IN OHMS

	Phase to Phase	Phase to Ground	Line to Load
Phase A			397.8 GΩ
Phase B			449 GΩ
Phase C			446 GΩ
Test Voltage:	5 kV		

Test Equipment Used: ES005

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

Fuses: No fuses in switch (not in use)

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Norther Ontario Wires	Customer P.O. #:	3301	Job #:	23068456
Tested by:	MJ	Date:	July 13, 2023	Cat #:	34530
Location:	Mill	Position:	Upper Town SW2	Manufacturer:	S&C
Rated Voltage:	5.5 kV	Close Voltage:	Manual	Type:	
Rated Current:	400 A	Open Voltage:	Manual	Year Built:	
Frequency:	60 Hz	Motor Voltage:	Manual	Model:	
Interrupt Current:		Motor Mech. Type:	N/A	Instruction manual:	
Ambient Temp.:	33°C	Weather Cond.:	Cloudy	Humidity:	27%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X			X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers	X			X			X		
18. Cleaned fuses			X			X			X
19. Condition of fuses			X			X			X
20. Verify correct fuse size			X			X			X
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened	X		
28. Latch mechanism	X		
29. Key interlocks	X		
30. Operating chain	X		
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater	X		
40. Screen/window cond'n	X		
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST IN OHMS

	Switch	Fuses
Phase A	102 μΩ	N/A
Phase B	86 μΩ	N/A
Phase C	103 μΩ	N/A
Test Current:	10A	

Test Equipment Used: ES008

INSULATION RESISTANCE TEST IN OHMS

	Phase to Phase	Phase to Ground	Line to Load
Phase A			405 GΩ
Phase B			475 GΩ
Phase C			361 GΩ
Test Voltage:	5 kV		

Test Equipment Used: ES005

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

Fuses: No fuses in switch (not in use)

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Norther Ontario Wires	Customer P.O. #:	3301	Job #:	23068456
Tested by:	MJ	Date:	July 13, 2023	Cat #:	34530
Location:	Mill	Position:	Lower Town SW3	Manufacturer:	S&C
Rated Voltage:	5.5 kV	Close Voltage:	Manual	Type:	
Rated Current:	400 A	Open Voltage:	Manual	Year Built:	
Frequency:	60 Hz	Motor Voltage:	Manual	Model:	
Interrupt Current:		Motor Mech. Type:	N/A	Instruction manual:	
Ambient Temp.:	33°C	Weather Cond.:	Cloudy	Humidity:	27%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X			X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers	X			X			X		
18. Cleaned fuses	X			X			X		
19. Condition of fuses	X			X			X		
20. Verify correct fuse size			X			X			X
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened	X		
28. Latch mechanism	X		
29. Key interlocks	X		
30. Operating chain	X		
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater	X		
40. Screen/window cond'n	X		
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST IN OHMS

	Switch	Fuses
Phase A	89 µΩ	280 µΩ
Phase B	74 µΩ	220 µΩ
Phase C	86 µΩ	410 µΩ
Test Current:	10A	

Test Equipment Used: ES008

INSULATION RESISTANCE TEST IN OHMS

	Phase to Phase	Phase to Ground	Line to Load
Phase A			558 GΩ
Phase B			289.2 GΩ
Phase C			243.2 GΩ
Test Voltage:	5 kV		

Test Equipment Used: ES005

	As Found	As Left
Operation Counter	N/A	N/A

COMMENTS:

Fuses: S&C Power fuse, Cat#: 86181, FOR: SM-5, AMP: 400E, 7.2kV

ANNEX E: CAMBRIDGE TRANSFORMER OIL RESULTS

SDMyers INTELLIGENT TRANSFORMER MANAGEMENT

Date Printed 8/15/2023 **TC# 9003**

Customer 6000885 Electek-Nother Ontario Wires **City** Sarnia, ON **Location** OUTDOOR
Sub-Name CAMBRIDGE **Unit No.** **Other**

NAMEPLATE DATA

Manufacturer	FERRANTI		**Equipment Type**	TRANSFORMER
Manufacture Date	1/1/1975		**Transformer Class**	ONAN
Serial No.	2-305235		**Impedance %**	5.40
KVA Rating	2,000		**Phase/Cycle**	3/60
High Voltage	12,000	D	**Liquid Type**	OIL
Low Voltage	4,160	Y	**Gallons**	267
Weight	24,691.7		**Other Access**	

ADDITIONAL EQUIPMENT

Radiators	Yes	**Conservator Tank**	
Fans	No	**LTC Compartment**	No
Water Cooled	No	**Bushing Location**	SIDE ENCL.
Oil Pumps	No	**Breather**	
Top FPV (inch)	0	**Hose Length (feet)**	
Bottom FPV (inch)	0	**Service Online**	
InsulationType	55C	**Power Available**	

VISUAL INSPECTION

DATE	LEVEL	SAMPLE TEMP	TOP TEMP	P/V	PAINT	LEAKS
07/09/23	NORMAL	26	55		GOOD	NONE

FIELD SERVICE

DATE	SERVICE

Additional Information

Reason Not Tested

LIQUID SCREEN TEST DATA

DATE	SERVICE	ACID	IFT	DIEL 877	DIEL 1816	GAP	COLOR		SP. GRAV.	VISUAL	SEDIMENT
07/09/23		0.030 AC	39.0 AC	47 AC			1.50	AC	0.876 AC	CLEAR AC	NONE AC

INHIBITOR CONTENT

DATE	PCT. BY WEIGHT
07/09/23	0.08% UN

NOTE - STUDIES SHOW THAT A LEVEL OF 0.3% INHIBITOR IS OPTIMUM FOR PRESERVATION OF IN-SERVICE TRANSFORMER OILS. OILS WITH A LEVEL BELOW 0.08% ARE CONSIDERED TO BE UNINHIBITED.

LIQUID POWER FACTOR

DATE	25 C	100 C
07/09/23	0.509 UN	11.400 UN

KEY TO ABBREVIATIONS: AC - ACCEPTABLE QU - QUESTIONABLE UN - UNACCEPTABLE RS - RESAMPLE

NOTE: * After a result indicates that the test or service was performed by an outside source.

SDMyers ACTS 4:12 INTELLIGENT TRANSFORMER MANAGEMENT

 Date Printed 8/15/2023 **TC# 9003**

Customer	6000885 Electek-Nother Ontario Wires	**S/N**	2-305235				
Sub-Name	CAMBRIDGE	**Mfg.**	FERRANTI	**Gallons**	267	**High Volt.**	12,000
Location	OUTDOOR	**Unit No.**		**KVA**	2,000	**Low Volt.**	4,160

KARL FISCHER TESTING MOISTURE CONTENT EXPRESSED IN PPM

DATE	AVG. TEMP	PPM	PCT. SATURATION		MOISTURE BY DRY WEIGHT PCT.
07/09/23	31	33	37 8	UN	4 03

RECOMMENDATION RETEST 3 MONTHS
The moisture content is unacceptable based on the equipment class and liquid type. A shorter test interval is recommended to monitor this unit.

FURAN ANALYSIS EXPRESSED IN PPB

DATE	5H2F	2FOL	2FAL	2ACF	5M2F	TOTAL
07/09/23	ND	ND	ND	ND	ND	ND

RECOMMENDATION RETEST 1 YEAR
THESE BASELINE DATA INDICATE THE CELLULOSIC INSULATION IS IN GOOD CONDITION.

CALCULATED DP 800 **EST. LIFE REMAINING** 100%

GAS-IN-OIL ANALYSIS GAS CHROMATOGRAPHY EXPRESSED IN PPM

DATE	HYDROGEN	OXYGEN	NITROGEN	METHANE	CARBON MONOXIDE	CARBON DIOXIDE	ETHANE	ETHYLENE	ACETYLENE	TOTAL COMBUST.	TOTAL GAS
07/09/23	ND	580	44,700	7	351	2,020	ND	14	ND	372	47,672

RECOMMENDATION RETEST 1 YEAR
A-THE ANALYSIS OF THIS SAMPLE SHOWS ONLY MINOR AMOUNTS OF COMBUSTIBLE GAS. THIS BASELINE INDICATES NORMAL OPERATION.

ICP METALS-IN-OIL EXPRESSED IN PPM

DATE	ALUMINUM	IRON	COPPER
07/09/23	<0.1	<0.03	0.03

RECOMMENDATION RETEST 1 YEAR
THERE ARE NO DIAGNOSTIC LEVELS OF METALS IN THIS SAMPLE.
THESE DATA CAN SERVE AS A BASELINE FOR FUTURE ANALYSES.

PCB CONTENT EXPRESSED IN PPM

DATE	1242	1254	1260	OTHER	TOTAL

NOTE: * After a result indicates that the test or service was performed by an outside source.

ANNEX F: PICTURES

Station ID:	Destroyes Substation		
Project File:	23068448	Date:	09-Jul-23
Client:	Northern Ontario Wires	Electek Rep:	Gary Taylor
Location:	Iroquois Falls, Ontario	Client Rep:	Marc Belanger

Comments:

Primary Connection Cabinet

Primary drained and cleaned. New gasket installed.

Comments:

Primary Connection Cabinet

Switch contacts cleaned. Contact resistance verified prior to closing cabinbet.

A = 202µΩ

B = 203µΩ

C = 189µΩ

ELECTEKPOWER

Station ID:	Destroyes Substation		
Project File:	23068448	Date:	09-Jul-23
Client:	Northern Ontario Wires	Electek Rep:	Gary Taylor
Location:	Iroquois Falls, Ontario	Client Rep:	Marc Belanger

Comments:

Conservator Level

(2) Barrels of voltesso 35 were added to the transformer and primary connection cabinet to bring the unit to proper level.

Comments:

Primary Connection Cabinet

Primary connection cabinet was filled with new volteso 35 to proper level.

ELECTEKPOWER

Station ID:	Destroyes Substation		
Project File:	23068448	Date:	09-Jul-23
Client:	Northern Ontario Wires	Electek Rep:	Gary Taylor
Location:	Iroquois Falls, Ontario	Client Rep:	Marc Belanger

Comments:

Conservator Piping

A leak was found at the conservator piping valve. Fitting was tightened to try and stop leak. Continue to monitor.

Comments:

ELECTEKPOWER

Station ID:	Mill Substation		
Project File:	23068448	Date:	09-Jul-23
Client:	Northern Ontario Wires	Electek Rep:	Myles Jennings
Location:	Iroquois Falls, Ontario	Client Rep:	Marc Belanger

Comments:

Mill substation transformer leak

Transformer is leaking from snorkel flange manhole cover.

Comments:

Rear of metering cabinet

Burnt fuseholder - potential transformer fuse holders are showing traces of heat

Note: PT's are not in use and several fuses are open.

Appendix D-2

TECHNICAL REPORT
Mateev Substation Maintenance

ELECTEKPOWER

TECHNICAL REPORT

Mateev Substation Maintenance

Prepared for:

Northern Ontario WIRES Inc.

287 Teefy Street
Iroquois Falls, Ontario
P0L 1C0

Prepared by:
Electek Power Services
12-868 Falconbridge Road
Sudbury, Ontario
P3A 5K7

Electek Reference #: 23088575
Customer Purchase Order: 3379

Prepared by: Gary Taylor
Field Service Manager

Date: August 2023

ELECTEKPOWER

TECHNICAL REPORT

September 13, 2023

Northern Ontario Wires
287 Teefy Street
Iroquois Falls, Ontario
P0L1C0

Attention: Mr. Marc Belanger

Subject: Mateev Substation Preventative Maintenance

Customer PO: 3379
Electek Ref.: 23088575

Dear Sir,

Please find attached our technical report pertaining to the preventative maintenance testing and inspections performed at the Mateev substation in August of 2023.

In general the equipment was found to be in fair operating condition. We have attached a brief summary of observations and recommendations that should be addressed.

Thank you for the opportunity to be of service. If you have any questions concerning this report, please do not hesitate to contact myself at (705) 507-1329.

Regards,

Gary Taylor
Field Service Manager
Northern Ontario

SUMMARY

Mateev Substation

Power Transformer

Observations
- Electrical test results – Primary winding resistance values found to exceed acceptable limits. No previous values were available for comparison.
- Visual inspection
  - H3 bushing is cracked, see attached picture.
  - Level gauge functions however faceplate is damaged.
- Oil analysis
  - Interfacial tension is below acceptable limits.
  - Acid content exceeds IEEE limits.
  - Oxidation inhibitor is below acceptable limit.
  - Moisture content exceeds IEEE limits.

Recommendations
- Inhibitor should be added to the unit in order to preserve general oil qualities.
- Consider replacing H3 bushing.
- Continue performing routine preventative maintenance testing.
- Resample unit annually to better trend rate of rise.

Switchgear

Observations
- Electrical test results – Acceptable, see attached
- Visual inspection
  - Protection relays should be tested and trip circuits verified.
  - Breakers are in poor condition. If switchgear is to remain in service consider sending a breaker out for a complete overhaul.
  - Feeder #1 and spare breaker were cleaned, lubricated and exercised.
  - Feeder #2 & #3 cables were disconnected from bus and taped off with 130C.
  - Switchgear was found very dirty.

Recommendations
- Perform routine preventative maintenance testing, inspections and cleaning on a more frequent basis.

27.6 KV Switch

Observations

- Electrical test results – Acceptable, see attached
- Visual inspection – Acceptable, unit was cleaned, lubricated and exercised.

Recommendations

- Perform routine preventative maintenance testing, inspections and cleaning on a more frequent basis.

27.6 KV Fuses

Observations

- Visual inspection
  - H1 Fuse was found bypassed. Jumper was removed and new fuse installed.
  - H3 Fuse holder had a broken insulator. Insulator was replaced with spare.

ELECTEKPOWER

ANNEX A: HV SWITCH TEST RESULTS

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Northern Ontario Wires	Customer P.O. #:	3379	Job #:	23088575
Tested by:	MJ	Date:	August 19, 2023	Cat #:	PH1HC14
Location:	Kapuskasing	Position:	19SS1GT	Manufacturer:	CLM Industries
Rated Voltage:	34.5kV	Close Voltage:	Manual	Type:	PH40
Rated Current:	600	Open Voltage:	Manual	BIL:	200 kV
Frequency:		Motor Voltage:	Manual	Model:	
Interrupt Current:	40 kA	Motor Mech. Type:	N/A	Instruction manual:	
Ambient Temp.:	15°C	Weather Cond.:	Cloudy	Humidity:	71%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X			X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers			X			X			X
18. Cleaned fuses			X			X			X
19. Condition of fuses			X			X			X
20. Verify correct fuse size			X			X			X
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened			X
28. Latch mechanism	X		
29. Key interlocks			X
30. Operating chain			X
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater			X
40. Screen/window cond'n			X
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST IN OHMS

	Switch	
Phase A	86 µΩ	
Phase B	42 µΩ	
Phase C	93 µΩ	
Test Current:	10A	

Test Equipment Used: ES008

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

Fuses: Cat#: 87114R1, nom.: 34.5kV, Amp max: 200E, refill unit SM-4

ANNEX B: TRANSFORMER TEST RESULTS

Mateev Transformer

ELECTEKPOWER

Client	Northern Ontario Wires		
Execution date	2023-08-19	Reason of the job	Routine
Tested by	Gary Taylor / Myles Jennings	Location	Mate□□Substation
Approved by		Asset	Transformer
Report ID	1	Asset type	Two-winding
Report issue date	2023 08 28 8:24:51 AM	Asset serial number	1-2086
Work order		Manufacturer	Ferranti Packard

Summary

H1-H2 winding resistance value elevated. No previous results to compare to. Monitor DGA results as issue may be caused by tap changer contacts.

Performed tests	Assessment
Overall PF & CAP	Pass
Exciting Current	Pass
Leakage Reactance H-X	Pass
TTR H-X	Pass
DC Winding Resistance H	Investigate
DC Winding Resistance X	Pass
Insulation Resistance	Pass

Overall Assessment	Acceptable

Tested by:
Gary Taylor

Approved by:

Location & company information

Location		Company	
Name	Northern Ontario Wires	Company	Electek Power Services
Region		Department	
Division		Address	12-868 Falconbridge Road
Area		City	Sudbury
Plant		State/Province	Ontario
Address	287 Teefy Street	Postal code	P3A 5K7
City	Iroquois Falls	Country	Canada
State/Province	Ontario	Phone No.	(705) 507-1329
Postal code	P0L 1C0	Fax No.	
Country	Canada	E-mail	gtaylor@electek.ca

Geo coordinates	

Contact person	
Name	Marc Belanger
Phone No. 1	(705) 232-8494
Phone No. 2	
Fax No.	
E-mail	marc.belanger@nowinc.ca

Comment

Transformer nameplate data

Serial number	1-2086	Apparatus ID	T1
Manufacturer	Ferranti Packard	Feeder	
Manufacturing year	1963	No. phases	3
Manufacturer type	ONS	Vector group	Dyn11

Comment

Voltage ratings

Winding	Voltage L-L	Voltage L-N	Insul. level L-L
H	27.600 kV	kV	200 kV
X	4.160 kV	2.402 kV	75 kV

Power ratings

Rated power	Cooling class	Temp. rise wind.
5.000 MVA	ON	55

Current ratings at rated power

Winding		
H	X	Rated power
104.500 A	694.000 A	5.000 MVA

Short-circuit rating

Max. short-circuit current	kA	s

Impedances

Ref. temp.	75 °C

Leakage reactance H - X

Zk[%]	Base power	Base voltage	Load losses Pk	OLTC position	DETC position
5.210 %	5.000 MVA	27.600 kV	W		1

Others

Category	Distribution
Status	In operation
Tank type	Sealed conservator
Insulation medium	Mineral oil
Fluid insulation volume	990 gals
Fluid insulation weight	8500 lbs
Total weight	33850 lbs

Tap Changers nameplate data

DETC

Serial number	
Manufacturer	
Manufacturer type	
Winding	H
Tap scheme	1...N
No. of taps	7

Tap	Voltage
1	27600.0 V
2	26910.0 V
3	26220.0 V
4	25530.0 V
5	24840.0 V
6	24150.0 V
7	23460.0 V

Test set information

Model	Serial number	Calibration date
TESTRANO 600	GK813Z	2023-02-15
CP TD12	CM745F	2023-02-15

Global test conditions

Weather	Clear	Humidity	78 %
Unit location	Outside	Ambient temperature	20 °C

Overall PF & CAP

Ambient temperature	20 °C	Weather	Clear
Top oil temperature	36 °C	Humidity	78 %

Comments

Standard test

Block 1: injection at H

Corr. temperature	36 °C
Corr. factor	0.7

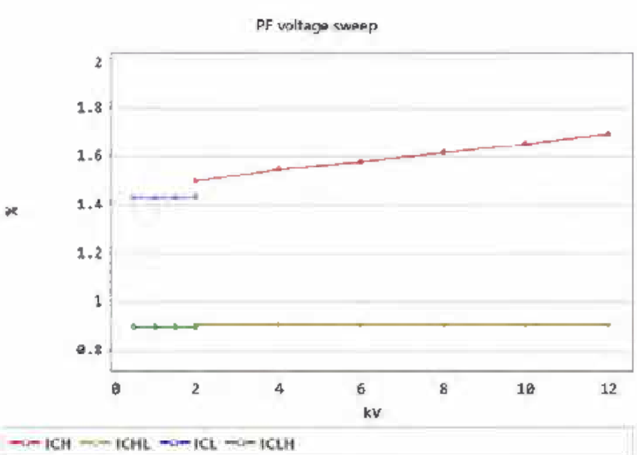
No.	Meas	Test mode	Freq.	V out	I out	Watt losses	PF meas	PF corr	Cap. meas	Assessment
1	ICH+ICHL	GST	60.00 Hz	10.00 kV	25.65 mA	4155.41 mW	1.6200 %	1.1340 %	6800.9 pF	Pass
2	ICH (V)	GSTg-A	60.00 Hz	10.00 kV	7.79 mA	1836.99 mW	2.3573 %	1.6501 %	2063.7 pF	Pass
3	ICHL (V)	UST-A	60.00 Hz	10.00 kV	17.86 mA	2302.19 mW	1.2891 %	0.9024 %	4737.2 pF	Pass

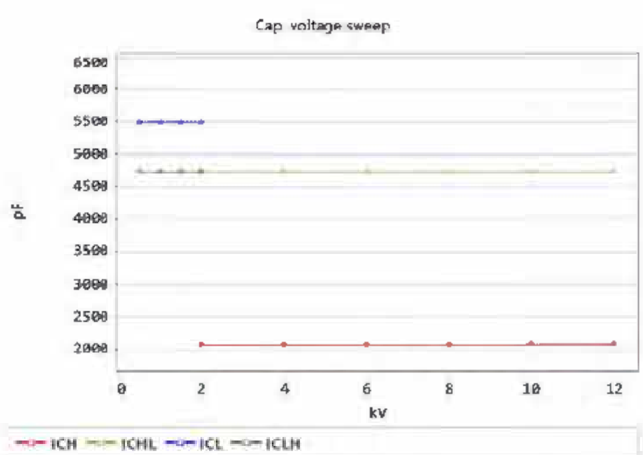
Block 2: injection at X

Corr. temperature	36 °C
Corr. factor	0.7

No.	Meas.	Test mode	Freq.	V out	I out	Watt losses	PF meas	PF corr	Cap. meas	Assessment
4	ICL+ICLH	GST	60.00 Hz	2.00 kV	7.71 mA	261.32 mW	1.6953 %	1.1867 %	10216.8 pF	Pass
5	ICL (V)	GSTg-A	60.00 Hz	2.00 kV	4.13 mA	169.18 mW	2.0465 %	1.4326 %	5478.9 pF	Pass
6	ICLH (V)	UST-A	60.00 Hz	2.00 kV	3.57 mA	90.84 mW	1.2717 %	0.8902 %	4736.9 pF	Pass

Graphs for voltage sweep





Exciting Current

Comment

Measurement settings

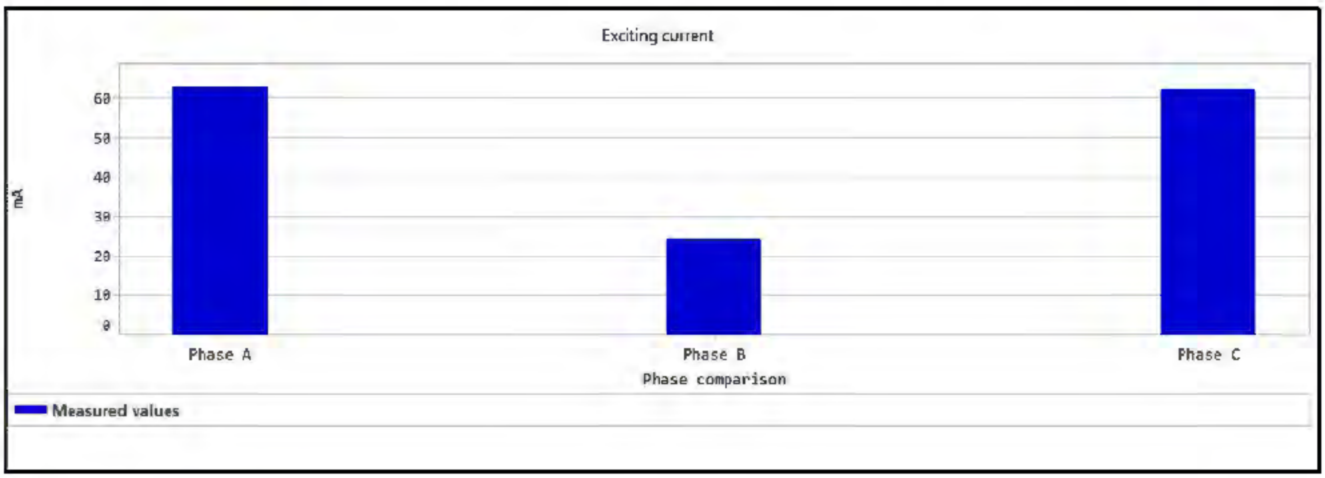
Test voltage	10 kV
Test frequency	60.00 Hz
Tap changer under test	DETC

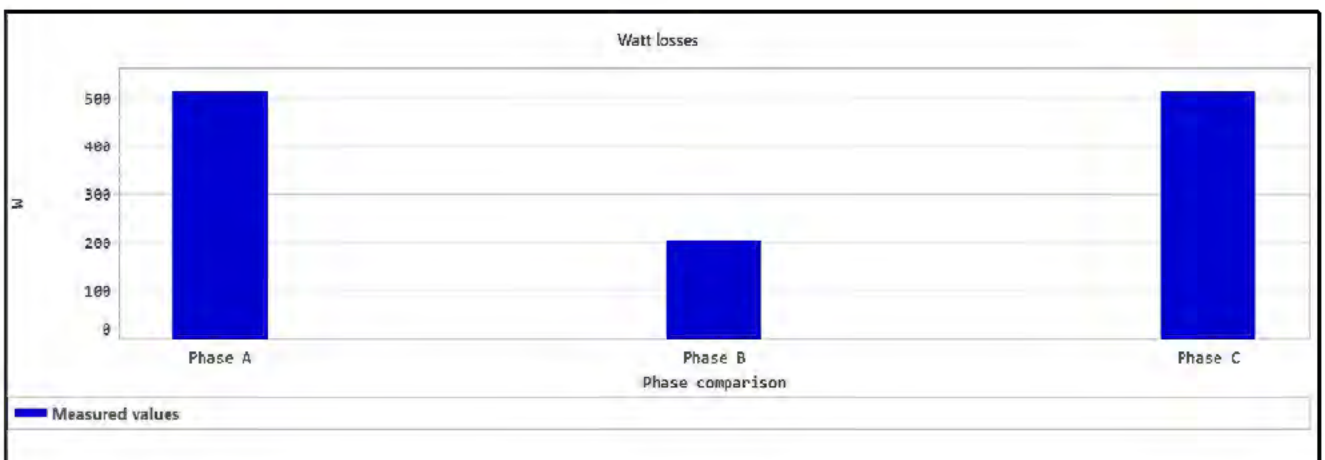
Averaging	2
Bandwidth	±20 Hz
AvoidTestFrequency	No

Use reference voltage	No

Measurements (sorted by tap)

Tap	*Phase*	*V out*	*I out*	*I phase*	*Watt losses*	*Reactance*	*Assessment*
5	A	10.00 kV	62.680 mA	-35.07 °	513.020 W	91.670 kΩ	Pass
5	B	10.00 kV	24.162 mA	-32.09 °	204.718 W	219.876 kΩ	Pass
5	C	10.00 kV	62.134 mA	-34.31 °	513.259 W	90.713 kΩ	Pass





Leakage Reactance H-X

Comment

Leakage reactance performed on as found tap position 5 for reference only. Actual leakage reactance value would be obtained on tap position 1.

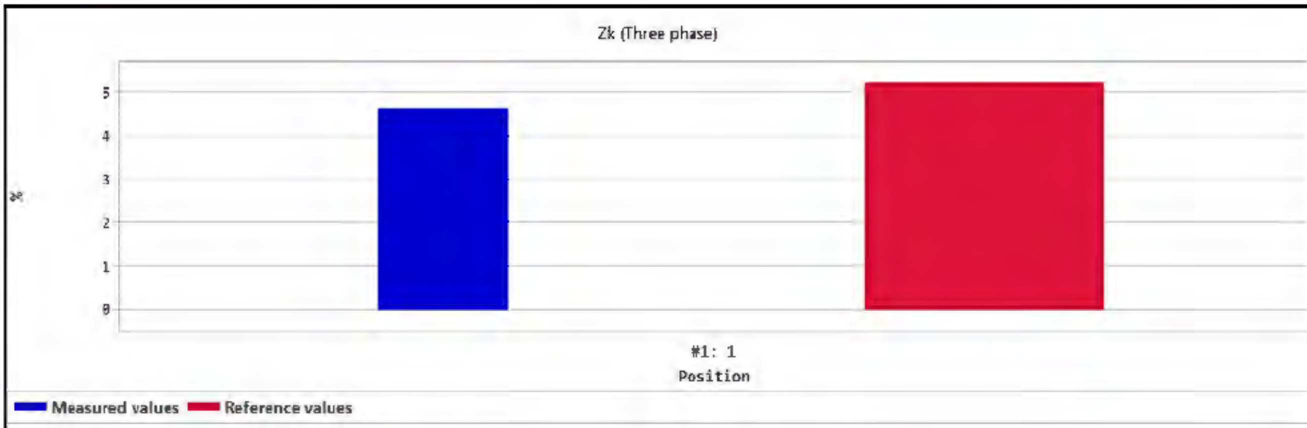
Measurement settings

Auto shorting	Enabled	Winding temperature	20 °C
Current limit	33.00 A	Reference temperature	75 °C
Default frequency	60.00 Hz	Temperature correction factor (K)	1
Winding material	Copper		

Result table for three phase test

Position	*Phase*	*Rk**	*Xk**	*Zk**	*Zk calc**	*Zk dev*	*Assessment*
#1: 1	A	501.714 mΩ	6.933 Ω	6.951 Ω	4.64 %	-11.03 %	Reference Measurement
	B	521.415 mΩ	7.093 Ω	7.112 Ω			
	C	488.822 mΩ	7.106 Ω	7.122 Ω			

Graphs for three phase test



TTR H-X

Comment

Measurement settings

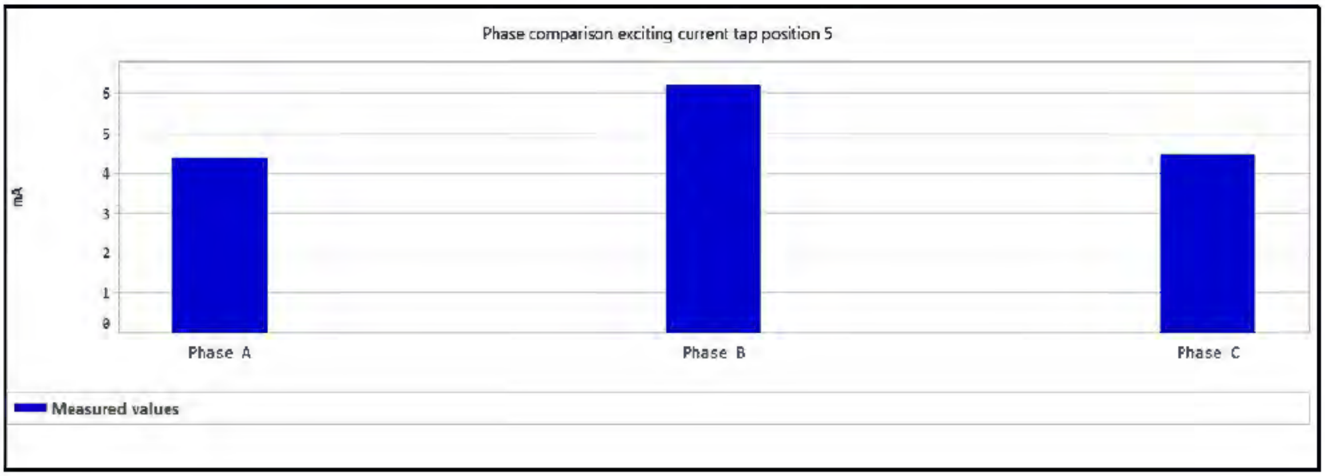
Test voltage	120 V
Test frequency	60.00 Hz
Tap changer under test	DETC

Ratio	TTR*

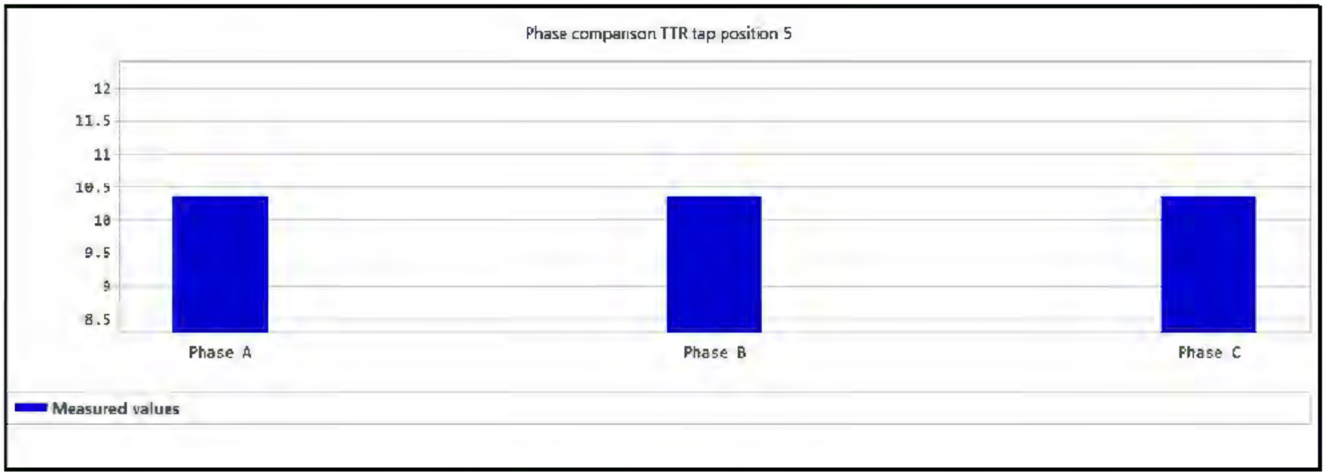
Measurements (sorted by tap)

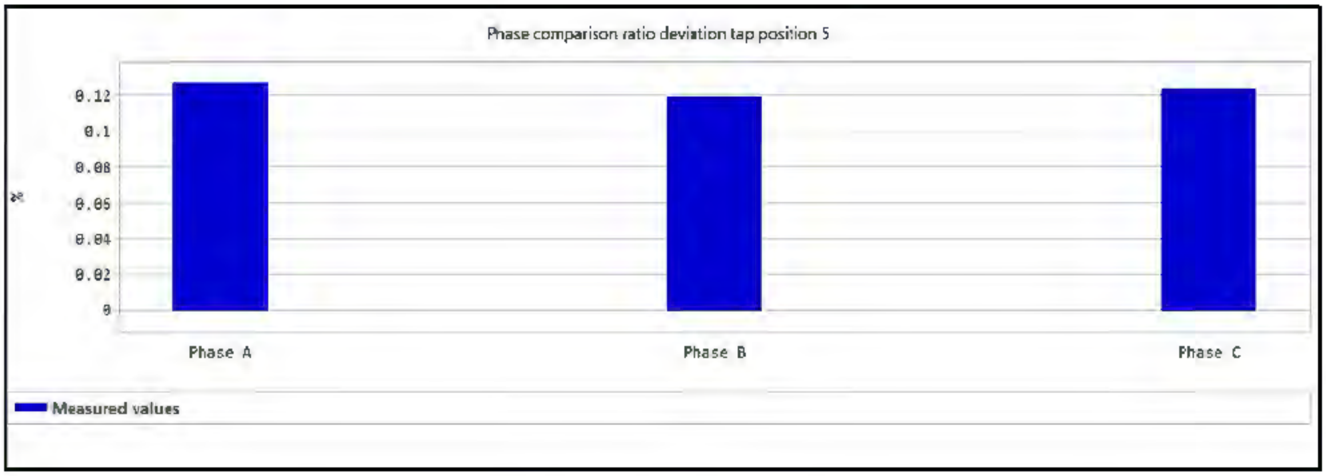
Tap	*Phase*	*Nom. Ratio*	*V prim (L-L)*	*I prim*	*V sec (L-L)*	*V phase*	*TTR**	*Ratio dev*	*Assessment*
5	A	10.3423	119.92 V	4.382 mA	20.06 V	330 °	10.3554	0.13 %	Pass
5	B	10.3423	119.92 V	6.199 mA	20.06 V	330.01 °	10.3546	0.12 %	Pass
5	C	10.3423	119.93 V	4.458 mA	20.06 V	330.01 °	10.3551	0.12 %	Pass

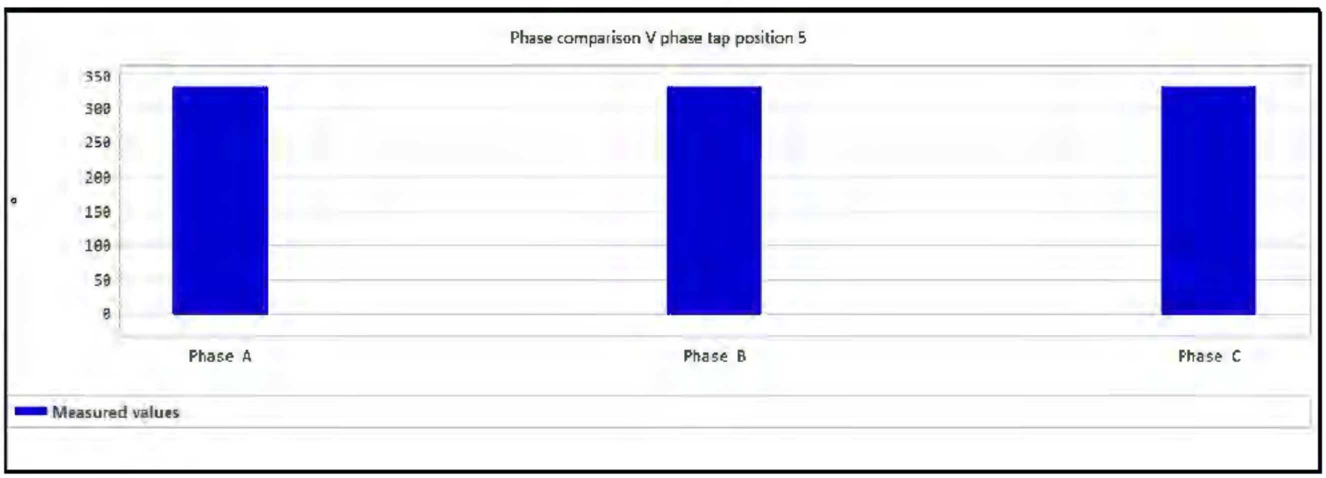
Graph for exciting current



Graphs for standard test







DC Winding Resistance H

Comment

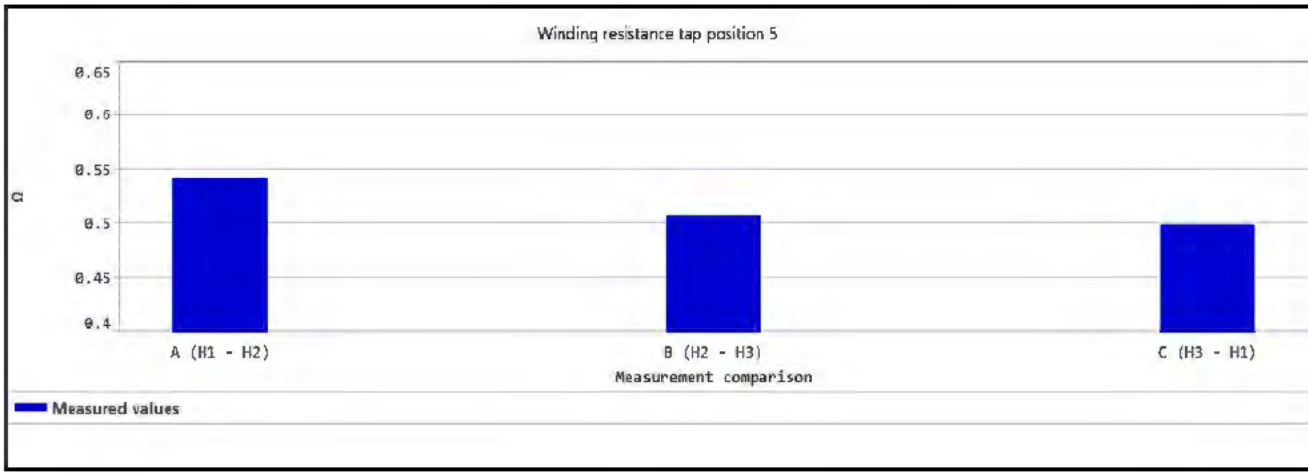
Measurement settings

Test current	5 A	Tap changer under test	DETC
Output mode	16 A @ 340 V		
	1 ph.		

Automatic result	True
Settling time (At)	5 s
Tolerance R dev	0.01 %
Recording time	200.0 ms

	A (H1 - H2)			*B (H2 - H3)*			*C (H3 - H1)*		
Tap	*R meas*	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*
5	541.772 mΩ	0.003 %	541.772 mΩ	506.993 mΩ	0.003 %	506.993 mΩ	497.974 mΩ	0.002 %	497.974 mΩ

Graphs for standard test



DC Winding Resistance X

Comment

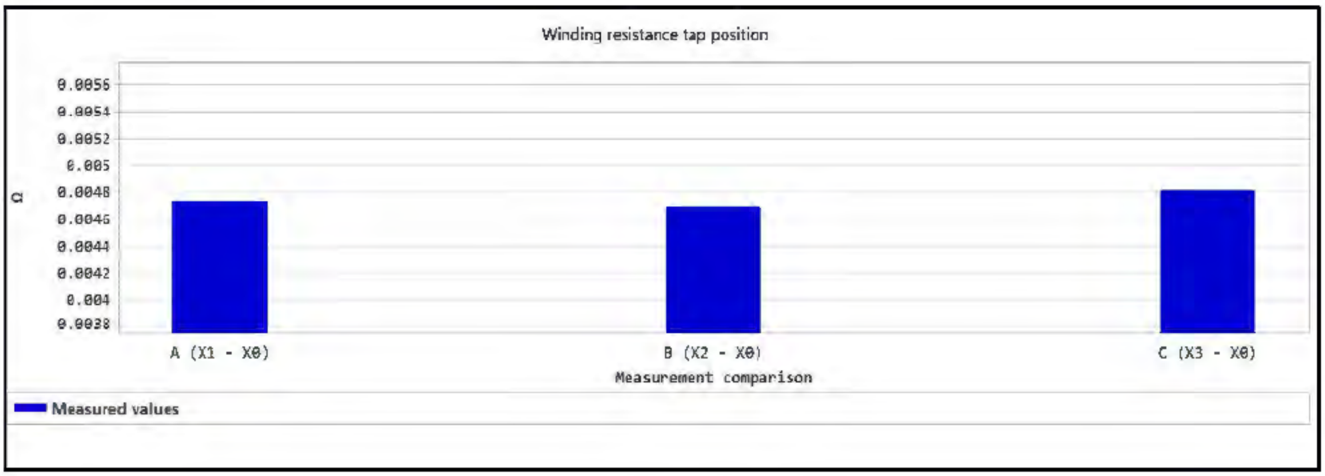
Measurement settings

Test current	5 A
Output mode	16 A @ 340 V
	1 ph.
Measurement	L-N

Automatic result	True
Settling time (At)	5 s
Tolerance R dev	0.05 %
Recording time	200.0 ms

A (X1 - X0)			*B (X2 - X0)*			*C (X3 - X0)*		
R meas	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*	*R meas*	*R dev*	*R corr*
4.731 mΩ	0.041 %	4.731 mΩ	4.692 mΩ	0.014 %	4.692 mΩ	4.809 mΩ	0.031 %	4.809 mΩ

Graphs for standard test



Insulation Resistance

Comment

Test object temperature	36 °C
Reference temperature	20 °C
Correction Factor	2,80

Ambient temperature	20 °C
Humidity	78 %

Name High - Low / Ground

Time	R meas	R corr	V DC	I DC
60 s	540.0 MΩ	1.512 GΩ	1.00 kV	1.852 µA

Name Low - High / Ground

Time	R meas	R corr	V DC	I DC
60 s	278.0 MΩ	778.4 MΩ	1.00 kV	3.597 µA

Name High / Low - Ground

Time	R meas	R corr	V DC	I DC
60 s	380.0 MΩ	1.064 GΩ	1.00 kV	2.632 µA

SDMyers INTELLIGENT TRANSFORMER MANAGEMENT

Date Printed 9/13/2023

TC# 9004

Customer	6000885 Electek-Northern Ontario Wires	**City**	Sarnia, ON	**Location**	OUTDOOR
Sub-Name	KAPUSKASING 2KV (MATEEV)	**Unit No.**	MATEEV TRANSFORMER	**Other**	

NAMEPLATE DATA

Manufacturer	FERRANTI PACKARD		**Equipment Type**	TRANSFORMER
Manufacture Date	1/1/1963		**Transformer Class**	
Serial No.	1-2086		**Impedance %**	5.31
KVA Rating	5,000		**Phase/Cycle**	3/60
High Voltage	27,600	D	**Liquid Type**	OIL
Low Voltage	4,160	Y	**Gallons**	990
Weight	33,850		**Other Access**	

ADDITIONAL EQUIPMENT

Radiators	Yes	**Conservator Tank**	
Fans	No	**LTC Compartment**	No
Water Cooled	No	**Bushing Location**	TOP
Oil Pumps	No	**Breather**	
Top FPV (inch)	0	**Hose Length (feet)**	
Bottom FPV (inch)	0	**Service Online**	
InsulationType	55C	**Power Available**	

VISUAL INSPECTION

DATE	LEVEL	SAMPLE TEMP	TOP TEMP	P/V	PAINT	LEAKS
08/19/23	NORMAL	25	30		GOOD	

FIELD SERVICE

DATE	SERVICE

Additional Information

Reason Not Tested

LIQUID SCREEN TEST DATA

DATE	SERVICE	ACID	IFT	DIEL 877	DIEL 1816	GAP	COLOR	SP. GRAV.	VISUAL	SEDIMENT
08/19/23		0.160 UN	28.2 QU	51 AC			3.00 AC	0.880 AC	CLEAR AC	NONE AC

INHIBITOR CONTENT

DATE	PCT. BY WEIGHT
08/19/23	<0.02% UN

NOTE - STUDIES SHOW THAT A LEVEL OF 0.3% INHIBITOR IS OPTIMUM FOR PRESERVATION OF IN-SERVICE TRANSFORMER OILS. OILS WITH A LEVEL BELOW 0.08% ARE CONSIDERED TO BE UNINHIBITED.

LIQUID POWER FACTOR

DATE	25 C	100 C
08/19/23	0.077 AC	3.520 OU

KEY TO ABBREVIATIONS: AC - ACCEPTABLE QU - QUESTIONABLE UN - UNACCEPTABLE RS - RESAMPLE

NOTE: * After a result indicates that the test or service was performed by an outside source.

SDMyers INTELLIGENT TRANSFORMER MANAGEMENT

 Date Printed 9/13/2023 **TC# 9004**

Customer	6000885 Electek-Northern Ontario Wires	**S/N**	1-2086				
Sub-Name	KAPUSKASING 2KV (MATEEV)	**Mfg.**	FERRANTI PACKARD	**Gallons**	990	**High Volt.**	27,600
Location	OUTDOOR	**Unit No.**	MATEEV TRANSFORMER	**KVA**	5,000	**Low Volt.**	4,160

KARL FISCHER TESTING MOISTURE CONTENT EXPRESSED IN PPM

DATE	AVG. TEMP	PPM	PCT. SATURATION		MOISTURE BY DRY WEIGHT PCT.
08/19/23	30	27	32.6	UN	3.51

RECOMMENDATION RETEST 3 MONTHS
The moisture content is unacceptable based on the equipment class and liquid type. A shorter test interval is recommended to monitor this unit.

FURAN ANALYSIS EXPRESSED IN PPB

DATE	5H2F	2FOL	2FAL	2ACF	5M2F	TOTAL
08/19/23	ND	ND	33	ND	ND	33

RECOMMENDATION RETEST 1 YEAR
THESE BASELINE DATA INDICATE THE CELLULOSIC INSULATION IS IN GOOD CONDITION.

CALCULATED DP 800 **EST. LIFE REMAINING** 100%

GAS-IN-OIL ANALYSIS GAS CHROMATOGRAPHY EXPRESSED IN PPM

DATE	HYDROGEN	OXYGEN	NITROGEN	METHANE	CARBON MONOXIDE	CARBON DIOXIDE	ETHANE	ETHYLENE	ACETYLENE	TOTAL COMBUST.	TOTAL GAS
08/19/23	12	13,300	31,200	ND	143	1,090	ND	20	ND	175	45,765

RECOMMENDATION RETEST 1 YEAR
A-THE ANALYSIS OF THIS SAMPLE SHOWS ONLY MINOR AMOUNTS OF COMBUSTIBLE GAS. THIS BASELINE INDICATES NORMAL OPERATION.

ICP METALS-IN-OIL EXPRESSED IN PPM

DATE	ALUMINUM	IRON	COPPER
08/19/23	<0.1	<0.03	0.17

RECOMMENDATION RETEST 1 YEAR
THERE ARE NO DIAGNOSTIC LEVELS OF METALS IN THIS SAMPLE.
THESE DATA CAN SERVE AS A BASELINE FOR FUTURE ANALYSES.

PCB CONTENT EXPRESSED IN PPM

DATE	1242	1254	1260	OTHER	TOTAL

NOTE: * After a result indicates that the test or service was performed by an outside source.

ANNEX C: MV BREAKER TEST RESULTS

ELECTEKPOWER

AIR MAGNETIC CIRCUIT BREAKER INSPECTION / TEST RESULTS

Customer:	Northern Ontario Wires	Customer P.O. #:	3379	Job #:	23088575
Tested by:	GT / MJ	Date:	August 19, 2023	Serial #:	1030
Location:	Kapuskasing	Position:	F1 Circuit Breaker	Manufacturer:	CLM Industries
Rated Voltage:	5.2 kV	Charge Voltage:		Type:	AE
Rated Current:	1200 A	Close Voltage:		Year Built:	
Frequency:	60 HZ	Trip Voltage:		Rated MVA:	250 MVA
Interrupt Current:	35 kA	Poles:	3	Trip Device Type:	Spring

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	PASS	FAIL	N/A
1. Cleaned mechanism	X		
2. Lubricated mechanism	X		
3. Racking mechanism	X		
4. Lubricated racking mechanism	X		
5. Manual charge, close, trip	X		
6. Charging motor			X
7. Motor disconnect switch			X
8. Electrical close/trip			X
9. Minimum close voltage			X
10. Minimum trip voltage			X
11. Undervoltage release			X
12. Operation of shunt trip coil			X
13. Status indicators	X		
14. Position indicator			X
15. Condition of primary disconnects	X		
16. Cleaned primary disconnects	X		
17. Lubricated primary disconnects	X		
18. Alignment of contacts	X		

	PASS	FAIL	N/A
19. Condition of secondary disconnects	X		
20. Cleaned secondary disconnects	X		
21. Operation of counter		X	
22. Mechanical interlocks			X
23. Bent or broken pieces	X		
24. Condition of arcing contacts	X		
25. Condition of main contacts	X		
26. Slow close operation			X
27. Shutter actuator	X		
28. Control wiring			X
29. Condition of arc chutes	X		
30. Cleaned arc chutes	X		
31. Cleaned interphase barriers	X		
32. Puffer operation	X		
33. Auxiliary contacts			X
34. Torque checks			X
35. Ready to be energized	X		

CONTACT RESISTANCE TEST IN MICRO OHMS

	As Found	As Left
Phase A	33.9 µΩ	33.9 µΩ
Phase B	32.7 µΩ	32.7 µΩ
Phase C	28.3 µΩ	28.3 µΩ
Test Current:	10A	

Test Equipment Used: ES008

INSULATION RESISTANCE TEST IN OHMS

	Phase to Phase	Phase to Ground	Line to Load
Phase A	13.28 GΩ	6.56 GΩ	216.3 MΩ
Phase B	10.22 GΩ	5.01 GΩ	1.402 GΩ
Phase C	13.20 GΩ	4.96 GΩ	7.02 GΩ
Test Voltage:	5 kV		

Test Equipment Used: ES005

COMMENTS:

ELECTEKPOWER

AIR MAGNETIC CIRCUIT BREAKER INSPECTION / TEST RESULTS

Customer:	Northern Ontario Wires	Customer P.O. #:	3379	Job #:	23088575
Tested by:	GT / MJ	Date:	August 19, 2023	Serial #:	1068
Location:	Kapuskasing	Position:	Spare	Manufacturer:	CLM Industries
Rated Voltage:	5.2 kV	Charge Voltage:		Type:	AE
Rated Current:	1200 A	Close Voltage:		Year Built:	
Frequency:	60 HZ	Trip Voltage:		Rated MVA:	250 MVA
Interrupt Current:	35 kA	Poles:	3	Trip Device Type:	Spring

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	PASS	FAIL	N/A
1. Cleaned mechanism	X		
2. Lubricated mechanism	X		
3. Racking mechanism	X		
4. Lubricated racking mechanism	X		
5. Manual charge, close, trip	X		
6. Charging motor			X
7. Motor disconnect switch			X
8. Electrical close/trip			X
9. Minimum close voltage			X
10. Minimum trip voltage			X
11. Undervoltage release			X
12. Operation of shunt trip coil			X
13. Status indicators	X		
14. Position indicator			X
15. Condition of primary disconnects	X		
16. Cleaned primary disconnects	X		
17. Lubricated primary disconnects	X		
18. Alignment of contacts	X		

	PASS	FAIL	N/A
19. Condition of secondary disconnects	X		
20. Cleaned secondary disconnects	X		
21. Operation of counter		X	
22. Mechanical interlocks			X
23. Bent or broken pieces	X		
24. Condition of arcing contacts	X		
25. Condition of main contacts	X		
26. Slow close operation			X
27. Shutter actuator	X		
28. Control wiring			X
29. Condition of arc chutes	X		
30. Cleaned arc chutes	X		
31. Cleaned interphase barriers	X		
32. Puffer operation	X		
33. Auxiliary contacts			X
34. Torque checks			X
35. Ready to be energized	X		

CONTACT RESISTANCE TEST
IN MICRO OHMS

	As Found	As Left
Phase A	45.8 µΩ	45.8 µΩ
Phase B	76.4 µΩ	76.4 µΩ
Phase C	48.4 µΩ	48.4 µΩ
Test Current:	10A	

Test Equipment Used: ES008

INSULATION RESISTANCE TEST
IN MEGOHMS

	Phase to Phase	Phase to Ground	Line to Load
Phase A	735 MΩ	246.4 MΩ	91.4 MΩ
Phase B	585 MΩ	363.5 MΩ	77.4 MΩ
Phase C	428 MΩ	136.2 MΩ	135.2 MΩ
Test Voltage:	5 kV		

Test Equipment Used: ES005

COMMENTS:

ANNEX D: PICTURES

ELECTEKPOWER

Station ID:	Mateev Substation		
Project File:	23088575	Date:	19-Aug-23
Client:	Northern Ontario Wires	Electek Rep:	GT / MJ
Location:	Kapuskasing, Ontario	Client Rep:	Marc Belanger

Comments:

H1 Fuse Holder

Top insulator fell apart when fuse holder was opened.

Comments:

H1 Fuse Holder

Insulator was replaced with spare unit.

ELECTEKPOWER

Station ID:	Mateev Substation		
Project File:	23088575	Date:	19-Aug-23
Client:	Northern Ontario Wires	Electek Rep:	GT / MJ
Location:	Kapuskasing, Ontario	Client Rep:	Marc Belanger

Comments:

MV Breakers

Breakers were cleaned and tested. It is recommended to have a unit sent for a complete overhaul if switchgear is to remain in service.

Comments:

Switchgear

All panels were removed for inspection and cells cleaned. Feeder #2 & #3 cables were removed from the bus and taped with 130C.

Northern Ontario WIRES Inc.

Appendix D-3

TECHNICAL REPORT
Cochrane Switch Maintenance

ELECTEKPOWER

TECHNICAL REPORT

Cochrane Switch Maintenance

Prepared for:

Northern Ontario WIRES Inc.

287 Teefy Street
Iroquois Falls, Ontario
P0L 1C0

Prepared by:
Electek Power Services
12-868 Falconbridge Road
Sudbury, Ontario
P3A 5K7

Electek Reference #: 23098658

Prepared by: Myles Jennings
Field Service Technologist

Date: October 2023

TECHNICAL REPORT

October 25 2023

Northern Ontario Wires
287 Teefy Street
Iroquois Falls, Ontario
P0L1C0

Attention: Mr. Marc Belanger

Subject: Cochrane Switch Maintenance

Electek Ref.: 23098658

Dear Marc,

Please find attached our technical report pertaining to the preventative maintenance and testing performed at the Cochrane MTS on September 10, 2023.

In general the equipment was found to be in fair operating condition and suitable for continued service. We were unable to test 28T1-L and 28A5H-G due to time constraints with the Hydro One outage. We have attached a brief summary of observations and recommendations that should be addressed.

Thank you for the opportunity to be of service. If you have any questions concerning this report, please do not hesitate to contact myself at (705) 561-4204.

Regards,

Myles Jennings
Electek Power Services
Field Service Technologist

SUMMARY

25kV Switchgear

Overall Switchgear
Observations
- Electrical Test Results – acceptable, see attached
- Visual Inspection – window seals are not completely sealed, see attached picture.

Recommendations
- Seal windows.

South Transformer Switch
Observations
- Electrical Test Results – acceptable, see attached
- Visual Inspection – broken C phase interrupter actuating arm – see attached picture.

Recommendations
- Replace broken interrupter arm component.

North Transformer Switch
Observations
- Electrical Test Results – acceptable, see attached
- Visual Inspection –Signs of heat in B phase cable – see attached picture.

Recommendations
- Perform thermography inspection of cables.

West Feeder Switch
Observations
- Electrical Test Results – **not acceptable**, interrupter was removed and switch was tagged out of service – interrupter is locked and does not change state causing switch arm to flex around it at point of contact, see attached picture.
- Signs of arcing on fuse ring.

Recommendations
- Replace defective interrupter and test prior to re-energization

East Feeder Switch
Observations
- Electrical Test Results – acceptable, see attached
- B phase interrupter insulator deteriorating – see attached picture.
- Phase barriers show signs of arching/damage - see attached picture.
- Bus bar is melted – see attached picture.

Recommendations
- Replace damaged insulators.
- Replace phase barriers.

115kV Switches

28T1-L
Observations
- Electrical Test Results – not tested due to time constraint.

Recommendations
- Perform preventative maintenance testing next outage.

28A5H-G
Observations
- Electrical Test Results – not tested due to time constraint.

Recommendations
- Perform preventative maintenance testing next outage.

28T2-L
Observations
- Electrical Test Results – high contact resistance was found, contact resistance was reduced after cleaning and realignment.
- Visual Inspection – cracked B phase insulator, see attached picture.

Recommendations
- Consider replacing cracked insulator.

28T3-L
Observations
- Electrical Test Results – acceptable, see attached.
- Visual Inspection – cracked C phase insulator, see attached picture.

Recommendations
- Consider replacing cracked insulator.

We encourage you to take the corrective actions that are proposed above. In addition a thermography inspection should be performed annually, coupled to a complete preventative maintenance including cleaning of the equipment every four years maximum. Through these actions you are contributing to maintain your equipment in good operating condition and minimizing the high costs resulting from a possible failure, as well as fostering the security of your operating personnel.

ANNEX A : 25 KV SWITCHGEAR

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Northern Ontario Wires	Customer P.O. #:		Job #:	23098658
Tested by:	MJ / AM	Date:	September 10, 2023	Cat #:	234553R2
Location:	Cochrane	Position:	South Transformer	Manufacturer:	S&C
Rated Voltage:	25 kV	Close Voltage:	Manual	Type:	Indoor – Three pole
Rated Current:	600A	Open Voltage:	Manual	Year Built:	
Frequency:		Motor Voltage:	Manual	Model:	
Interrupt Current:		Motor Mech. Type:	N/A	Instruction manual:	762-35
Ambient Temp.:	14°C	Weather Cond.:	Cloudy	Humidity:	62%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X			X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers	X			X			X		
18. Cleaned fuses	X			X			X		
19. Condition of fuses	X			X			X		
20. Verify correct fuse size	X			X			X		
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Interupter	X			X			X		
26. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened	X		
28. Latch mechanism	X		
29. Key interlocks	X		
30. Operating chain	X		
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater	2.18A		
40. Screen/window cond'n		X	
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST

	Switch	Fuses
Phase A	85.0 µΩ	
Phase B	88.0 µΩ	
Phase C	80.0 µΩ	
Test Current:	10A	

Test Equipment Used: ES007

INSULATION RESISTANCE TEST

	Phase to Phase	Phase to Ground	Line to Load
Phase A			333 GΩ
Phase B			440 GΩ
Phase C			410 GΩ
Test Voltage:	5 kV		

Test Equipment Used: ES005

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

C phase interrupter arm broken – see attached picture.
Windows not completely sealed – see attached picture.

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Northern Ontario Wires	Customer P.O. #:		Job #:	23098658
Tested by:	MJ / AM	Date:	September 10, 2023	Cat #:	234553R2
Location:	Cochrane	Position:	North Transformer	Manufacturer:	S&C
Rated Voltage:	25 kV	Close Voltage:	Manual	Type:	Indoor – Three pole
Rated Current:	600 A	Open Voltage:	Manual	Year Built:	
Frequency:		Motor Voltage:	Manual	Model:	
Interrupt Current:		Motor Mech. Type:	N/A	Instruction manual:	762-35
Ambient Temp.:	14°C	Weather Cond.:	Cloudy	Humidity:	62%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X			X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers	X			X			X		
18. Cleaned fuses	X			X			X		
19. Condition of fuses	X			X			X		
20. Verify correct fuse size	X			X			X		
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Interrupter	X			X			X		
26. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened	X		
28. Latch mechanism	X		
29. Key interlocks	X		
30. Operating chain	X		
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater	2.14A		
40. Screen/window cond'n		X	
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST

	Switch	Fuses
Phase A	83.7 µΩ	
Phase B	82.0 µΩ	
Phase C	78.0 µΩ	
Test Current:	10A	

Test Equipment Used: ES007

INSULATION RESISTANCE TEST

	Phase to Phase	Phase to Ground	Line to Load
Phase A			380 GΩ
Phase B			465 GΩ
Phase C			300 GΩ
Test Voltage:	5 kV		

Test Equipment Used: ES005

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

Windows not completely sealed – see attached picture.
Signs of heat on B phase cable – see attached picture.

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Northern Ontario Wires	Customer P.O. #:		Job #:	23098658
Tested by:	MJ / AM	Date:	September 10, 2023	Cat #:	234513R4-T1
Location:	Cochrane	Position:	West Feeder	Manufacturer:	S&C
Rated Voltage:	23 kV	Close Voltage:	Manual	Type:	Indoor
Rated Current:	600A	Open Voltage:	Manual	Year Built:	
Frequency:		Motor Voltage:	Manual	Model:	
Interrupt Current:		Motor Mech. Type:	N/A	Instruction manual:	772-35
Ambient Temp.:	14°C	Weather Cond.:	Cloudy	Humidity:	62%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X			X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers	X			X			X		
18. Cleaned fuses	X			X			X		
19. Condition of fuses	X			X			X		
20. Verify correct fuse size	X			X			X		
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Interrupter	X				X		X		
26. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened	X		
28. Latch mechanism	X		
29. Key interlocks			X
30. Operating chain	X		
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater	2.30A		
40. Screen/window cond'n		X	
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST

	Switch	Fuses
Phase A	85.8 µΩ	692.2 µΩ
Phase B	85.1 µΩ	671.4 µΩ
Phase C	86.8 µΩ	518.3 µΩ
Test Current:	10A	

Test Equipment Used: ES007

INSULATION RESISTANCE TEST

	Phase to Phase	Phase to Ground	Line to Load
Phase A			268 GΩ
Phase B			493 GΩ
Phase C			463 GΩ
Test Voltage:	5 kV		

Test Equipment Used: ES005

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

Fuses: S&C Power Fuse Holder, Type: 4S, Catalog #: 86633R1, Nominal: 25kV, Max: 27kV, Amperes max: 200E, Refill unit: SM-4
B phase interrupter has signs of arching and is defective (does not change state) – causing the arm to flex around it, interrupter was removed and the switch was tagged out of service – see attached picture.
Signs of arching on fuse ring – see attached picture.
Windows not completely sealed – see attached picture.

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Northern Ontario Wires	Customer P.O. #:		Job #:	23098658
Tested by:	MJ / AM	Date:	September 10, 2023	Cat #:	234513R4-T1
Location:	Cochrane	Position:	East Feeder	Manufacturer:	S&C
Rated Voltage:	23 kV	Close Voltage:	Manual	Type:	Indoor
Rated Current:	600A	Open Voltage:	Manual	Year Built:	
Frequency:		Motor Voltage:	Manual	Model:	
Interrupt Current:		Motor Mech. Type:	N/A	Instruction manual:	772-35
Ambient Temp.:	14°C	Weather Cond.:	Cloudy	Humidity:	62%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X				X		X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers		X			X			X	
18. Cleaned fuses	X			X			X		
19. Condition of fuses	X			X			X		
20. Verify correct fuse size	X			X			X		
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened	X		
28. Latch mechanism	X		
29. Key interlocks			X
30. Operating chain	X		
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater	2.25A		
40. Screen/window cond'n		X	
41. Control wiring			X
42. Torque checks			X
43. Ready to be energized	X		

CONTACT RESISTANCE TEST

	Switch	Fuses
Phase A	82.3 µΩ	448.2 µΩ
Phase B	83.9 µΩ	568.1 µΩ
Phase C	82.5 µΩ	737.1 µΩ
Test Current:	10A	

Test Equipment Used: ES007

INSULATION RESISTANCE TEST

	Phase to Phase	Phase to Ground	Line to Load
Phase A			334 GΩ
Phase B			408 GΩ
Phase C			475 GΩ
Test Voltage:	5 kV		

Test Equipment Used: ES005

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

Fuses: S&C Power Fuse Holder, Type: 4Z, Catalog #: 86633R2, Nominal: 25kV, Max: 27kV, Amperes max: 200E, Refill unit: SM-4
B phase insulator is cracked and deteriorating – see attached pictures.
Signs of arching throughout entire cell – melted bus bar, carbon residue on walls and barriers – see attached pictures.
Consider replacing damaged insulators and barriers.
Windows not completely sealed – see attached [illegible]

ELECTEKPOWER

SWITCHGEAR BUS RESISTANCE

Customer:	Northern Ontario Wires	Customer P.O. #:		Job #:	23098658
Tested by:	MJ / AM	Date:	September 10, 2023	Cat #:	CDT-236061
Location:	Cochrane	Position:	Enclosed Switchgear	Manufacturer:	S&C
Rated Voltage:	23 kV	Type:	Metal Enclosed		
Rated Current:	600 A	Year Built:			
Frequency:		Model:			
Interrupt Current:		Instruction manual:	629-2C		
Temperature:	14°C	Weather Cond.:	Cloudy	Humidity:	62%

Acceptance Testing: ☐ Maintenance Testing: ☒

CONTACT RESISTANCE

DESIGNATION	CELL	PHASE	μΩ
South Transformer Switch Load Side	North Transformer Switch Load Side	A	321.2
		B	234.9
		C	208.0
South Transformer Switch Load Side	West Feeder Switch Line Side	A	1005
		B	850.5
		C	850.7
South Transformer Switch Load Side	East Feeder Switch Line Side	A	1163
		B	992.5
		C	989.6
South Transformer Cell Ground	East Feeder Cell Ground		
		GND	358.2

Test Equipment Used: ES001 @ 200A

OVER POTENTIAL TEST IN MICRO AMPS ☒ MILLIAMPS ☐ MEGOHMS ☐

Insulation Resistance @ 45kVAC	East & West A to B,C,GND	East & West B to A, C, GND	East & West C to A, B, GND	North & South A to B,C,GND	North & South B to A, C, GND	North & South C to A, B, GND
	130	124	129	126	113	112

Test Equipment Used: ES011 See Separate Sheet for Dielectric Withstand: YES ☐ NO ☒

COMMENTS:

Bus bar was separated at center cell to isolate metering transformer for over potential testing

ANNEX B : 115 KV SWITCHES

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Northern Ontario Wires	Customer P.O. #:		Job #:	23098658
Tested by:	MJ / AM	Date:	September 10, 2023	Cat #:	215-286
Location:	Cochrane	Position:	28T2-L	Manufacturer:	Kearney-National
Rated Voltage:	138 kV	Close Voltage:	Manual	Type:	Air Switch (AVB)
Rated Current:	1200 A	Open Voltage:	Manual	Year Built:	1975
Frequency:	60 HZ	Motor Voltage:	Manual	Model:	
Interrupt Current:	70 kA	Motor Mech. Type:	N/A	Instruction manual:	
Ambient Temp.:	14°C	Weather Cond.:	Cloudy	Humidity:	62%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X				X		X		
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers			X			X			X
18. Cleaned fuses			X			X			X
19. Condition of fuses			X			X			X
20. Verify correct fuse size			X			X			X
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened			X
28. Latch mechanism	X		
29. Key interlocks	X		
30. Operating chain			X
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater			X
40. Screen/window cond'n			X
41. Control wiring			X
42. Torque checks			X
43. Blade angle	A: 94.2	B: 92.5	C: 93.4
44. Ready to be energized	X		

CONTACT RESISTANCE TEST

	As Found	As Left
Phase A	439 µΩ	212 µΩ
Phase B	433 µΩ	202 µΩ
Phase C	469 µΩ	220 µΩ
Test Current:	200A	

Test Equipment Used: ES001

	As Found	As Left
Operation Counter	N/A	N/A

COMMENTS:

As found contact resistance was – A: 439 µΩ, B: 433 µΩ, C: 469 µ. Upon cleaning and realigning contacts the contact resistance was brought down.

Fuses: S&C SMD-2B Fuse Unit, 65E, Standard Speed TCC 153-1

[illegible]

ELECTEKPOWER

DISCONNECT SWITCH INSPECTION / TEST RESULTS

Customer:	Northern Ontario Wires	Customer P.O. #:		Job #:	23098658
Tested by:	MJ / AM	Date:	September 10, 2023	Cat #:	215-286
Location:	Cochrane	Position:	28T3-L	Manufacturer:	Kearney-National
Rated Voltage:	25 kV	Close Voltage:	Manual	Type:	Air Switch (AVB)
Rated Current:	600A	Open Voltage:	Manual	Year Built:	1975
Frequency:	60 HZ	Motor Voltage:	Manual	Model:	
Interrupt Current:	70 kA	Motor Mech. Type:	N/A	Instruction manual:	
Ambient Temp.:	14°C	Weather Cond.:	Cloudy	Humidity:	62%

Acceptance Testing: ☐ Maintenance Testing: ☒

ELECTRICAL / MECHANICAL INSPECTION

	Phase A			Phase B			Phase C		
	PASS	FAIL	N/A	PASS	FAIL	N/A	PASS	FAIL	N/A
1. Cleaned insulators	X			X			X		
2. Blade alignment	X			X			X		
3. Blade condition	X			X			X		
4. Jaw condition	X			X			X		
5. Stationary arcing horn condition	X			X			X		
6. Stationary arcing horn alignment	X			X			X		
7. Moving arcing blade condition	X			X			X		
8. Moving arcing blade alignment	X			X			X		
9. Condition of insulators	X			X				X	
10. Open stops	X			X			X		
11. Close stops	X			X			X		
12. Blade pressure	X			X			X		
13. Blade wipe	X			X			X		
14. Operating arm connections	X			X			X		
15. Ground connections	X			X			X		
16. Arc chute condition			X			X			X
17. Barriers			X			X			X
18. Cleaned fuses			X			X			X
19. Condition of fuses			X			X			X
20. Verify correct fuse size			X			X			X
21. Alignment checks	X			X			X		
22. Blade opens to spec's	X			X			X		
23. Blade closes to spec's	X			X			X		
24. Torque checks			X			X			X
25. Ready to energize	X			X			X		

	PASS	FAIL	N/A
26. Operating mechanism	X		
27. Covers fastened			X
28. Latch mechanism	X		
29. Key interlocks	X		
30. Operating chain			X
31. Operation of shunt trip			X
32. Warning indication			X
33. Ground connection	X		
34. Auxiliary switches			X
35. Motor disconn. switch			X
36. Electrical open			X
37. Electrical close			X
38. Motor condition			X
39. Enclosure heater			X
40. Screen/window cond'n			X
41. Control wiring			X
42. Torque checks			X
43. Torque checks			X
44. Blade angle	A: 92.5	B: 91.4	C: 93.4
45. Ready to be energized	X		

CONTACT RESISTANCE TEST

	Switch	Fuses
Phase A	127 μΩ	
Phase B	136 μΩ	
Phase C	148 μΩ	
Test Current:	200A	

Test Equipment Used: ES001

Operation Counter	As Found	As Left
	N/A	N/A

COMMENTS:

Fuses: S&C SMD-2B Fuse Unit, 65E, Standard Speed TCC 153-1

LA's: ASEA XAE 132AS, 132 kV, Class 10kA, 50hz

[illegible]

ANNEX C : PICTURE SHEET

ELECTEKPOWER

Station ID:		Cochrane MTS	
Project File:	23098658	Date:	10-Sep-23
Client:	Northern Ontario Wires	Electek Rep:	MJ / AM
Location:	Cochrane	Client Rep:	Marc Belanger

Comments:

South Transformer Switch

C phase actuating arm showing signs of damage.

Comments:

ELECTEKPOWER

Station ID:		Cochrane MTS	
Project File:	23098658	Date:	10-Sep-23
Client:	Northern Ontario Wires	Electek Rep:	MJ / AM
Location:	Cochrane	Client Rep:	Marc Belanger

Comments:

North Transformer Cell

All cell windows have spaces through seals (North, South, East and West cells)

Comments:

North Transformer Switch - B phase

Signs of heat on B - phase cable

ELECTEKPOWER

Station ID:	Cochrane MTS		
Project File:	23098658	Date:	10-Sep-23
Client:	Northern Ontario Wires	Electek Rep:	MJ / AM
Location:	Cochrane	Client Rep:	Marc Belanger

Comments:

West Feeder Switch - B Phase

Interrupter shows signs of arcing

Switch arm flexes around interupter actuator since interrupter is locked and does not change state

Comments:

West Feeder Switch - B phase

Interupter was removed and is no longer causing a restriction to the B - phase.
NOTE: SWITCH IS TAGGED AND SHOULD NOT BE OPEN UNDER LOAD

ELECTEKPOWER

Station ID:	Cochrane MTS		
Project File:	23098658	Date:	10-Sep-23
Client:	Northern Ontario Wires	Electek Rep:	MJ / AM
Location:	Cochrane	Client Rep:	Marc Belanger

Comments:

West Feeder - B Phase

Melted B - phase fuse ring

Comments:

Station ID:	Cochrane MTS		
Project File:	23098658	Date:	10-Sep-23
Client:	Northern Ontario Wires	Electek Rep:	MJ / AM
Location:	Cochrane	Client Rep:	Marc Belanger

Comments:

East Feeder Cell

Melted bus bar

Signs of arcing

Comments:

East Feeder Switch - A phase

A Phase barrier showing signs of a previous fault.

A phase insulator showing signs of a previous fault.

ELECTEKPOWER

Station ID:	Cochrane MTS		
Project File:	23098658	Date:	10-Sep-23
Client:	Northern Ontario Wires	Electek Rep:	MJ / AM
Location:	Cochrane	Client Rep:	Marc Belanger

Comments:

East Feeder - B Phase (rear view)

B phase vertical insulator deterioating

Comments:

East Feeder - B Phase (front view)

B phase horizontal insulator deterioating

ELECTEKPOWER

Station ID:	Cochrane MTS		
Project File:	23098658	Date:	10-Sep-23
Client:	Northern Ontario Wires	Electek Rep:	MJ / AM
Location:	Cochrane	Client Rep:	Marc Belanger

Comments:

28T3-L

C phase insulator cracked

Comments:

28T2-L

B phase insulator cracked

Appendix D-4

Visual Inspection Report

Visual Inspection Report

Date: 2023-04-20
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: Ferranti
Unit ID: 2086
Unit Serial: 2086

Transformer Items	Good	Fair	Poor	Comments
Main Tank	X			
Bushings	X			
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level	X			Reading: 25 Oil level gauge should be replaced
Gauges		X		Oil level gauge should be replaced
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			

Substation Items	Good	Fair	Poor	Comments
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Costumer requested to see if nameplate could be replaced for this unit

Supervisor Signature: M.G

Visual Inspection Report

Date: 2023-04-25	**Transformer Manufacturer:** Feranti
Stark Job Number: NOW-ON-02-230178	**Unit ID:** 1-2577
Company: Nowinc	**Unit Serial:** 1-2577
Address: Cochrane, ON	
Supervisor: Mike Gillis	

Transformer Items	Good	Fair	Poor	Comments
Main Tank			X	Leaks on top / tap changer
Bushings			X	Leaking from bushing box, regasket needed
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level			X	Reading: Low on oil not reading on gauge
Gauges	X			
Valves		X		Leaking valve on bottom on conservator
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			
Substation Items	**Good**	**Fair**	**Poor**	**Comments**
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Transformer is leaking from bushings and tap changer

Supervisor Signature: M G

Visual Inspection Report

Stark International

Date: 2023-04-20
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: English electric
Unit ID: 203107
Unit Serial: 203107

Transformer Items	Good	Fair	Poor	Comments
Main Tank			X	appears to be leaking from the top, could be a possible regasket off the lid or a leaking bushing, cannot determine which, transformer is live
Bushings		X		Possible leak from top bushings, can't determine due to transformer being live
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level			X	Reading: Low reading needs oil
Gauges	X			
Valves			X	Leaking valve on the conservator, possibly just needs to be tightened or re-taped
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			

Substation Items	Good	Fair	Poor	Comments
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Transformer is leaking and really low on oil, should be maintenanced asap

Supervisor Signature: M. G

Visual Inspection Report

Date: 2023-04-20
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: English electric
Unit ID: 203108
Unit Serial: 203108

Transformer Items	Good	Fair	Poor	Comments
Main Tank			X	Leaking from top of transformer, could possibly be the lid or a bushing on the top of the transformer, cannot access the top, transformer is live
Bushings	X			
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level		X		Reading: 15
Gauges	X			
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			
Substation Items	**Good**	**Fair**	**Poor**	**Comments**
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Supervisor Signature:

M G

Visual Inspection Report

Stark International

Date: 2023-04-20
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: English electric
Unit ID: 203109
Unit Serial: 203109

Transformer Items	Good	Fair	Poor	Comments
Main Tank		X		Possible leak from top lid, visual oil on ground and side of transformer, cannot access top due to transformer being live
Bushings	X			
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level		X		Reading: 20
Gauges			X	Temperature gauge is leaking. Face plate is really weathered. Hard to read temperature, visual oil on back of gauge leaking
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			
Substation Items	**Good**	**Fair**	**Poor**	**Comments**
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Leaking temperature gauge needs a replacement gauge

Supervisor Signature: MG

Visual Inspection Report

Date: 2023-04-20
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: English Electric
Unit ID: 258423
Unit Serial: 258423

Transformer Items	Good	Fair	Poor	Comments
Main Tank	X			
Bushings	X			
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level	X			Reading: 20
Gauges		X		Temperature gauge needs to be re-taped, possible leak coming from back side screwing into the well
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			

Substation Items	Good	Fair	Poor	Comments
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Supervisor Signature: MG

Visual Inspection Report

Date: 2023-04-25
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: Ferranti
Unit ID: 261784
Unit Serial: 261784

Transformer Items	Good	Fair	Poor	Comments
Main Tank			X	Leaking from gasket on tap changer, leaking from both bushing cabinets, should be taken off line and regasket done, also possible leak from top lid, can't access - live
Bushings			X	Leaking from both bushing cabinets, should be tightened or regasket
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level		X		Reading: 15 Little low
Gauges		X		Level gauge has leak, should be addressed
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			

Substation Items	Good	Fair	Poor	Comments
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Transformers is leaking in several spots should be repairs asap

Supervisor Signature: MC

Visual Inspection Report

Date: 2023-04-20
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: Ferranti
Unit ID: 269579
Unit Serial: 269579

Transformer Items	Good	Fair	Poor	Comments
Main Tank		X		Small leak on explosion vent, need to re-gasket
Bushings	X			
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level	X			Reading: 25
Gauges			X	Tap changer's level gauge has moisture in face plate, the main tank level gauge is also leaking. It has visual oil inside the gauge
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			There is a small leak coming from the explosion vent, need a re-gasket
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			
Substation Items	**Good**	**Fair**	**Poor**	**Comments**
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Supervisor Signature: M G

Visual Inspection Report

Date: 2023-04-20
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: English Electric
Unit ID: 272423
Unit Serial: 272423

Transformer Items	Good	Fair	Poor	Comments
Main Tank	X			
Bushings	X			
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level	X			Reading: 28
Gauges	X			
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			

Substation Items	Good	Fair	Poor	Comments
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Supervisor Signature: M. G

Visual Inspection Report

Stark International

Date:	2023-04-20	**Transformer Manufacturer:**	English Electric
Stark Job Number:	NOW-ON-02-230178	**Unit ID:**	T2A
Company:	Nowinc	**Unit Serial:**	286604
Address:	Cochrane, ON		
Supervisor:	Mike Gillis		

Transformer Items	Good	Fair	Poor	Comments
Main Tank	X			
Bushings	X			
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level	X			Reading: 20
Gauges	X			
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			

Substation Items	Good	Fair	Poor	Comments
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Supervisor Signature: MG

Visual Inspection Report

Date: 2023-04-25
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: Ferranti
Unit ID: 305235
Unit Serial: 305235

Transformer Items	Good	Fair	Poor	Comments
Main Tank	X			
Bushings	X			
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level	X			Reading: 20
Gauges	X			
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			

Substation Items	Good	Fair	Poor	Comments
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

Supervisor Signature: M.C

Visual Inspection Report

Date: 2023-04-20
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: CGE
Unit ID: East feeder
Unit Serial: North transformer

Transformer Items	Good	Fair	Poor	Comments
Main Tank	X			
Bushings	X			
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level	X			Reading: 20
Gauges	X			
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			

Substation Items	Good	Fair	Poor	Comments
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

No name plate should be replaced

Supervisor Signature: M.G

Visual Inspection Report

Date: 2023-04-20
Stark Job Number: NOW-ON-02-230178
Company: Nowinc
Address: Cochrane, ON
Supervisor: Mike Gillis

Transformer Manufacturer: Unknown
Unit ID: West feeder
Unit Serial: South transformer

Transformer Items	Good	Fair	Poor	Comments
Main Tank	X			Missing name plate
Bushings	X			
Transfomer Grounds 2 / Unit	X			
Lightning Arrestors	X			
Oil Level	X			Reading: 25
Gauges	X			
Valves	X			
Radiators	X			
Gas Pressure	X			PSI/inHG: 0
Pressure / Explosion Vent	X			
PCB Labels	X			
Neutral Isolated	X			
Silica Gel	X			

Substation Items	Good	Fair	Poor	Comments
Gates	X			
Locks	X			
Fence	X			
Grounds	X			
Gravel	X			
Weeds	X			
High Voltage Signs	X			
Air Break Switches Ground	X			
Insulators	X			
Ground Mats	X			

Notes

No nameplate, need a new one

Supervisor Signature: M. G

Appendix D-5

Transformer Oil Data

Northern Ontario Wires

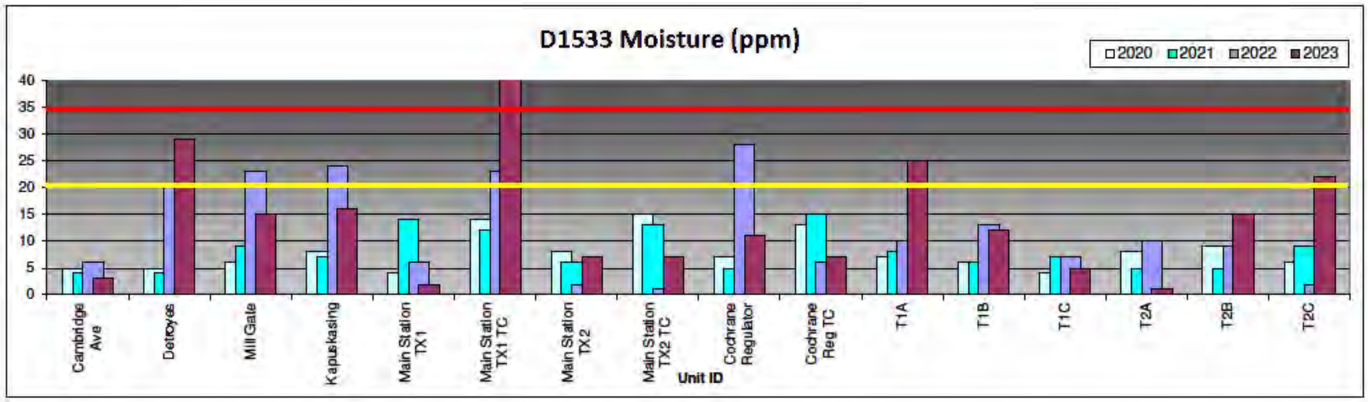
Unit ID	Cambridge Ave	Detroyes	Mill Gate	Kapuskasing	Main Station TX1	Main Station TX1 TC	Main Station TX2	Main Station TX2 TC
Serial Number	305235	1-2577	261784	1-2086	288692	288692	288693	288693
Location	Iroquois Falls	Iroquois Falls	Iroquois Falls	Kapuskasing	Cochrane	Cochrane	Cochrane	Cochrane
Manufacturer	Ferranti-Packard	Ferranti-Packard	Ferranti-Packard	Ferranti-Packard	CGE	CGE	CGE	CGE
Year of Manufacture	1975	1966	1955	1963	1975	1975	1975	1975
Power Rating (MVA)	2.0	4.0	2.0	5.0	7.5	7.5	7.5	7.5
Voltage	12kV/4.16kV	12kV/4kV/2.3kV	12kV	25kV/4.16kV	115kV/24.94kV	115kV/24.94kV	115kV/24.94kV	115kV/24.94kV
Fluid Volume	267 Imp Gal	1370 Imp Gal	1420 Imp Gal	990 Imp Gal	3095 Imp Gal	165 Imp Gal	3095 Imp Gal	165 Imp Gal
Fluid Type	Mineral Oil	Mineral Oil	Mineral Oil	Mineral Oil	Mineral Oil	Mineral Oil	Mineral Oil	Mineral Oil
Breathing	Sealed	Conservator	Conservator	Conservator	Conservator		Conservator	Conservator
Sample Date	25-Apr-23	25-Apr-23	25-Apr-23	20-Apr-23	20-Apr-23	20-Apr-23	20-Apr-23	20-Apr-23
Laboratory No.	1768	1765	1764	1703	1705	1706	1707	1708
Container No.	39006	38681	36976	38398	39115	39162	37486	39813
Temperature (C)		15	15	20	25	25	25	25
H2 - Hydrogen (ppm)	1	16	1	12	5	151	11	92
CH4 - Methane (ppm)	<1	<1	<1	<1	<1	28	<1	31
C2H6 - Ethane (ppm)	9	<1	<1	<1	<1	5	<1	4
C2H4 - Ethylene (ppm)	27	2	3	62	20	88	37	67
C2H2 - Acetylene (ppm)	<1	<1	<1	<1	<1	582	<1	593
CO - Carbon monoxide (ppm)	892	11	45	519	382	156	659	14
CO2 - Carbon dioxide (ppm)	3801	1307	1579	3465	2533	1600	3284	1255
N2 - Nitrogen (ppm)	66091	97824	96199	92960	96779	96031	93320	86209
O2 - Oxygen (ppm)	1582	40517	34758	35621	36936	35509	33831	39413
Total (ppm)	72403	139677	132585	132639	136655	134150	131142	127678
TDCG (ppm)	929	29	49	593	407	1010	707	801
D1533 Moisture (ppm)	3	29	15	16	2	155	7	7
D971 Interfacial Tension (dynes/cm)	36.1	36.2	26.3	25.0	30.4	18.0	30.2	37.0
D974 Acid Number (mg KOH/g)	0.007	0.001	0.024	0.042	0.008	0.313	0.004	0.006
D1500 Color Number	<2.0	1.0	1.0	2.5	<0.5	<3.5	<0.5	<2.5
D1524 Visual Examination	Clear & Bright	Clear & Bright	Clear & Bright	Clear & Bright	Clear & Bright	Clear & Bright	Clear & Bright	Clear & Bright
D1816 Dielectric BV (kV)	18	23	19	38	39	31	35	27
D924 Power Factor (% at 25 C)	0.618	0.010	0.022	0.116	0.192	0.188	0.016	0.017
D2668 Oxidation Inhibitor (%)	0.120	0.050	0.090	0.100	0.100		0.330	
D1298 Specific Gravity	0.875	0.855	0.865	0.880	0.858	0.862	0.855	0.870
PCB Content (ppm)	<1	2.3	2.3	12.9	36.0	41.9	9.3	<1
5-Hydroxy-methyl-furaldehyde (ppm)	<0.005	<0.005	<0.005	<0.005	<0.005		<0.005	
2-Furaldehyde (ppm)	0.017	0.017	0.216	0.056	0.026		0.015	
2-Acetylfuran (ppm)	<0.005	<0.005	0.008	<0.005	<0.005		<0.005	
5-Methyl-2-furaldehyde (ppm)	<0.005	<0.005	0.010	<0.005	<0.005		<0.005	
2-Furyl alcohol (ppm)	<0.005	<0.005	<0.005	<0.005	<0.005		<0.005	

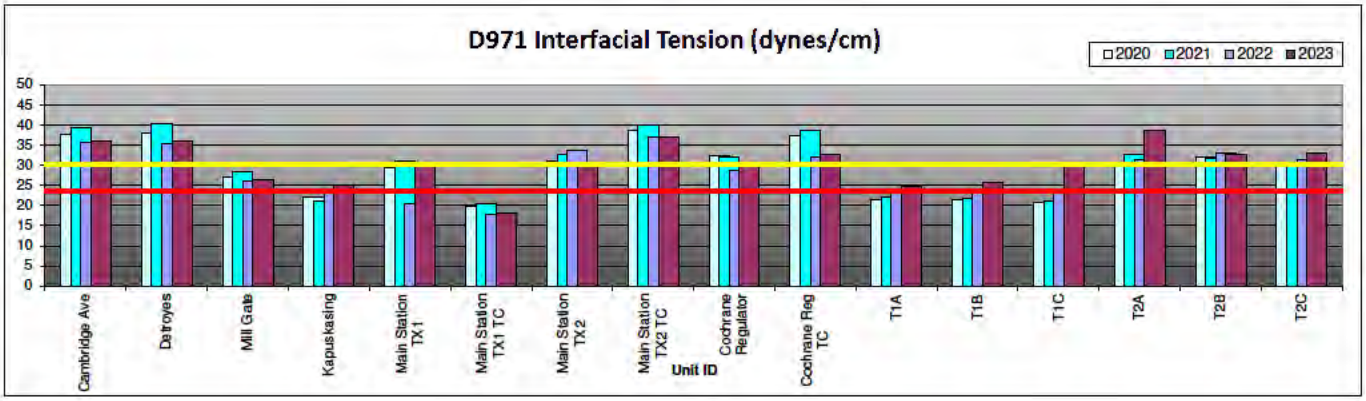
Northern Ontario Wires

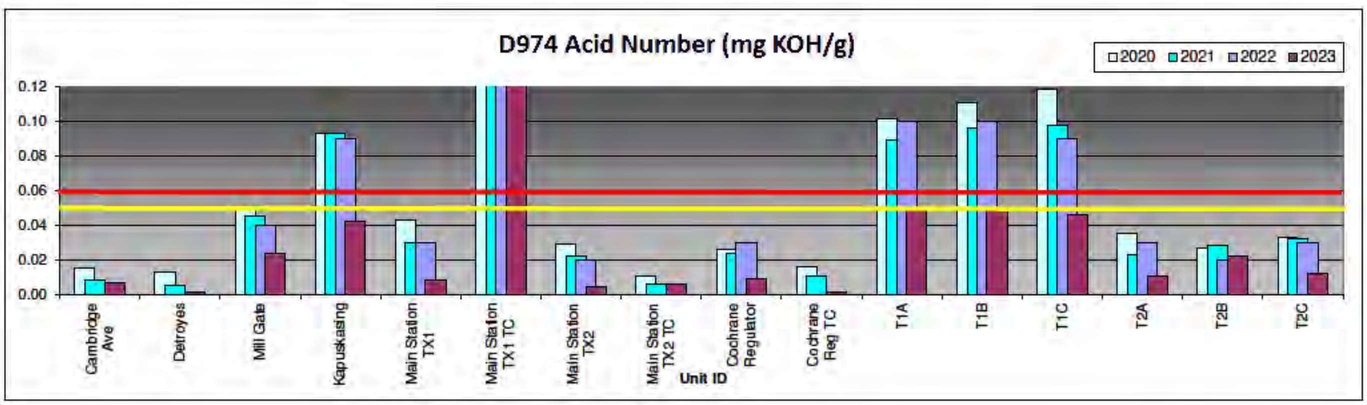
Unit ID	Cochrane Regulator	Cochrane Reg TC	T1A	T1B	T1C	T2A	T2B	T2C
Serial Number	269579	269579	203109	203108	203107	286604	272423	258423
Location	Cochrane	Cochrane	Cochrane	Cochrane	Cochrane	Cochrane	Cochrane	Cochrane
Manufacturer	Ferranti-Packard	Ferranti-Packard	English Electric Co.	English Electric Co.	English Electric Co.	English Electric Co.	English Electric Co.	English Electric Co.
Year of Manufacture			1953	1953	1953	1960	1959	1957
Power Rating (MVA)	5.2	5.2	1.0	1.0	1.0	1.0	1.0	1.0
Voltage	4.16kV	4.16kV	110kV/2.4kV	110kV/2.4kV	110kV/2.4kV	115kV	115kV	115kV
Fluid Volume	588 Imp Gal	72 Imp Gal	1225 Imp Gal	1225 Imp Gal	1225 Imp Gal	1225 Imp Gal	1225 Imp Gal	1225 Imp Gal
Fluid Type	Mineral Oil	Mineral Oil	Mineral Oil	Mineral Oil	Mineral Oil	Mineral Oil	Mineral Oil	Mineral Oil
Breathing	Sealed		Conservator	Conservator	Conservator	Conservator	Conservator	Conservator
Sample Date	20-Apr-23	20-Apr-23	25-Apr-23	25-Apr-23	20-Apr-23	25-Apr-23	25-Apr-23	25-Apr-23
Laboratory No.	1709	1710	1766	1763	1704	1770	1767	1769
Container No.	38652	IFZ514	38697	37050	38407	37115	38891	36967
Temperature (C)	20	20	20	20	20	15	20	15
H2 - Hydrogen (ppm)	42	5	5	8	12	2	24	3
CH4 - Methane (ppm)	1	2	4	<1	1	<1	<1	<1
C2H6 - Ethane (ppm)	2	3	6	4	4	<1	<1	5
C2H4 - Ethylene (ppm)	3	66	7	8	8	3	4	11
C2H2 - Acetylene (ppm)	<1	69	<1	<1	<1	<1	<1	<1
CO - Carbon monoxide (ppm)	20	24	140	176	286	51	44	236
CO2 - Carbon dioxide (ppm)	1832	1485	2557	2830	3692	2024	1669	3443
N2 - Nitrogen (ppm)	93486	94704	93091	95644	95755	49888	89284	51320
O2 - Oxygen (ppm)	32285	44829	41141	44296	40187	26892	47673	25313
Total (ppm)	127671	141154	136951	142966	139945	78860	138698	80331
TDCG (ppm)	68	136	162	196	311	56	72	255
D1533 Moisture (ppm)	11	7	25	12	5	1	15	22
D971 Interfacial Tension (dynes/cm)	29.7	32.7	24.8	25.9	30.2	38.7	32.7	33.1
D974 Acid Number (mg KOH/g)	0.009	0.001	0.049	0.050	0.046	0.011	0.022	0.012
D1500 Color Number	<1.0	<1.5	1.5	<1.5	<2.0	<1.5	1.0	<1.5
D1524 Visual Examination	Clear & Bright	Clear & Bright	Clear & Bright	Clear & Bright	Clear & Bright	Clear & Bright	Clear & Bright	Clear & Bright
D1816 Dielectric BV (kV)	33	20	29	26	35	45	25	18
D924 Power Factor (% at 25 C)	0.031	0.053	0.110	0.078	0.094	0.028	0.026	0.020
D2668 Oxidation Inhibitor (%)	0.170		0.020	0.090	0.100	0.050	0.050	0.050
D1298 Specific Gravity	0.865	0.865	0.848	0.848	0.865	0.875	0.870	0.878
PCB Content (ppm)	5.0	10.8	3.2	5.6	4.3	21.6	16.2	6.0
5-Hydroxy-methyl-furaldehyde (ppm)	<0.005		<0.005	<0.005	<0.005	0.011	0.007	<0.005
2-Furaldehyde (ppm)	0.286		0.076	0.161	0.166	0.185	0.091	0.031
2-Acetylfuran (ppm)	0.012		0.014	<0.005	0.013	<0.005	<0.005	<0.005
5-Methyl-2-furaldehyde (ppm)	0.015		0.037	0.035	0.026	0.016	0.015	<0.005
2-Furyl alcohol (ppm)	<0.005		<0.005	<0.005	<0.005	<0.005	<0.005	<0.005

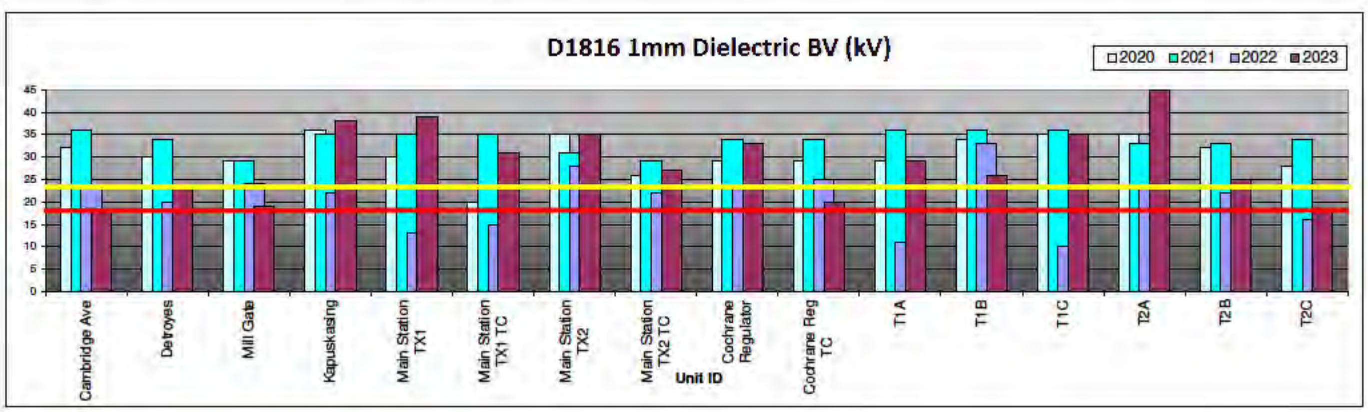
Appendix D-6

Transformer Oil Data Charts

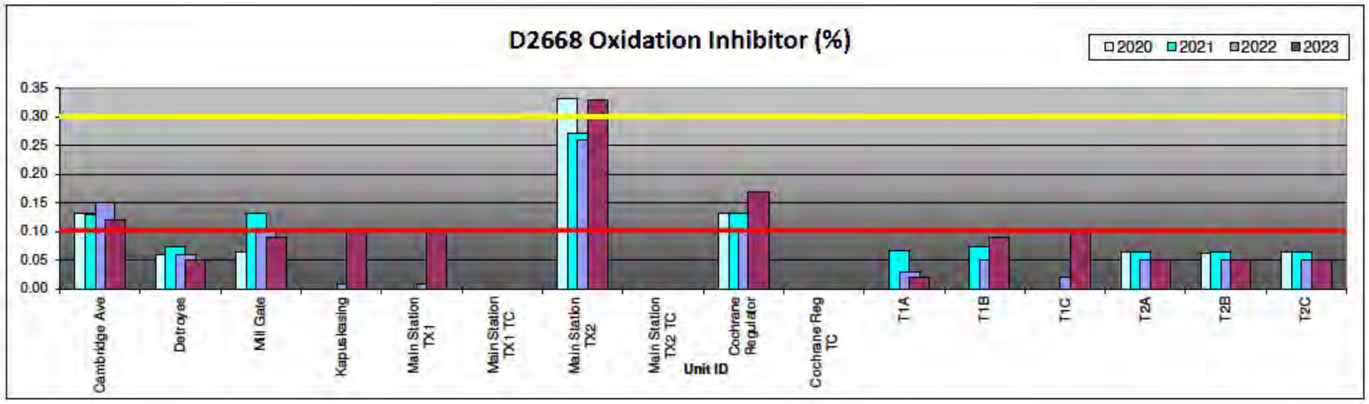


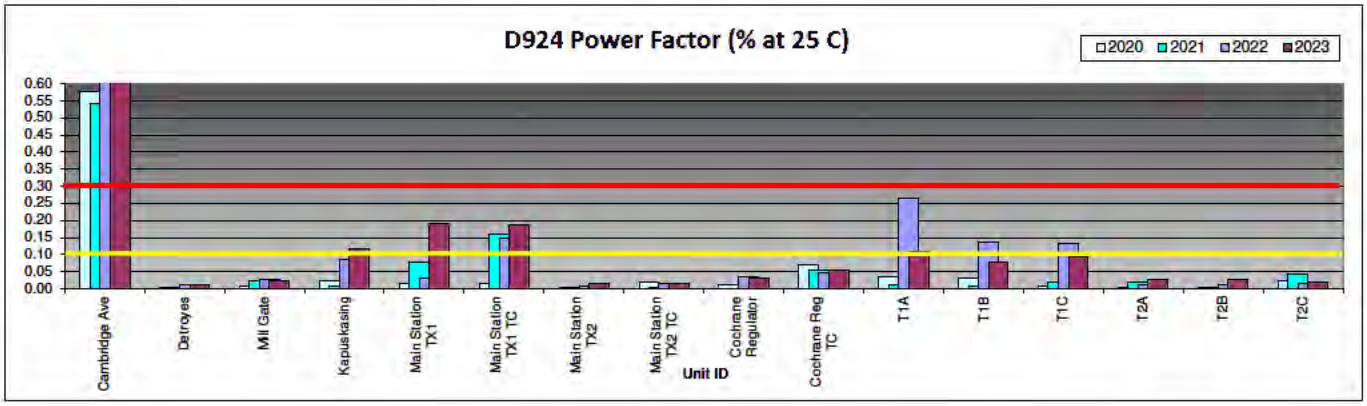


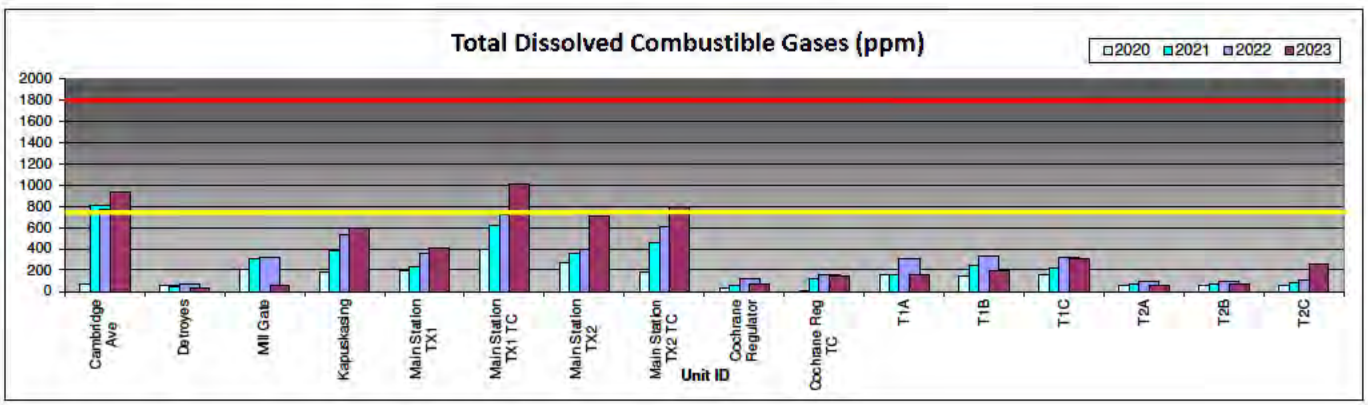




Warning Level
Acceptance







Warning Level
Acceptance

Appendix D-7

Transformer Oil Diagnostics Report

Oil Diagnostics Report

Dan Boucher
Northern Ontario Wires
153 Sixth Ave
Cochrane, ON P0L 1C0

Stark International Inc.
113 Archimedes Street
New Glasgow, Nova Scotia
B2H 2T3

22-Jun-23

Toll Free: 1-877-875-2775 Fax: (902) 755-2949

Unit ID	**Cambridge Ave**	Power Rating (MVA)	**2.0**
Serial Number	**305235**	Voltage	**12kV/4.16kV**
Location	**Iroquois Falls**	Fluid Volume	**267 Imp Gal**
Manufacturer	**Ferranti-Packard**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1975**	Preservation	**Sealed**

	Sample Date	**25-Apr-23**	25-May-22	4-May-21	13-May-20
	Laboratory No.	**1768**	212	5073555	5070248
	Container No.	**39006**	36006	48583	45862
	Temperature (ºC)		35	25	19
H_2	Hydrogen (ppm)	**1**	<1	10	4
CH_4	Methane (ppm)	**<1**	19	8	1
C_2H_6	Ethane (ppm)	**9**	5	4	<1
C_2H_4	Ethylene (ppm)	**27**	21	22	10
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**892**	725	770	57
CO_2	Carbon dioxide (ppm)	**3801**	3177	2710	631
N_2	Nitrogen (ppm)	**66091**	90828	102759	69796
O_2	Oxygen (ppm)	**1582**	5300	5860	32033
	Total Gas (ppm)	**72403**	100075	112143	102532
	Total Combustible Gas (ppm)	**929**	770	814	72
D1533	Moisture (ppm)	**3**	6	4	5
D971	Interfacial Tension (dynes/cm)	**36.1**	35.6	39.3	37.6
D974	Acid Number (mg KOH/g)	**0.007**	<0.02	0.008	0.015
D1500	Color Number	**<2.0**	2.0	<2.0	L2.0
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**18**	23	36	32
D924	Power Factor (% at 25 ºC)	**0.618**	0.629	0.541	0.579
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.120**	0.150	0.130	0.132
D1298	Specific Gravity	**0.875**	0.875	0.875	0.874
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**<1**	ND	<1.0	1.63
	Degree of Polymerization	**937**	1000	953	961
	Estimated % Life Remaining	**100**	100	100	100

Interpretation: ***Carbon monoxide (892 ppm) is slightly elevated. Power factor (0.618% at 25 °C) and dielectric breakdown voltage (18 kV) are unacceptable. All other oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.120%) is effective. Furans DP is 937. PCB is reported as <1 ppm.***

Recommendation: ***Resample to verify dielectric breakdown voltage.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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22-Jun-23

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Unit ID	**Detroyes**	Power Rating (MVA)	**4.0**
Serial Number	**1-2577**	Voltage	**12kV/4kV/2.3kV**
Location	**Iroquois Falls**	Fluid Volume	**1370 Imp Gal**
Manufacturer	**Ferranti-Packard**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1966**	Preservation	**Conservator**

	Sample Date	**25-Apr-23**	25-May-22	4-May-21	13-May-20
	Laboratory No.	**1765**	222	5073544	5070237
	Container No.	**38681**	36095	48594	45850
	Temperature (ºC)	**15**	30	25	20
H_2	Hydrogen (ppm)	**16**	<1	9	9
CH_4	Methane (ppm)	**<1**	2	2	1
C_2H_6	Ethane (ppm)	**<1**	<1	<1	<1
C_2H_4	Ethylene (ppm)	**2**	2	1	2
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**11**	70	36	38
CO_2	Carbon dioxide (ppm)	**1307**	1277	839	804
N_2	Nitrogen (ppm)	**97824**	82677	77066	81257
O_2	Oxygen (ppm)	**40517**	15550	37396	36441
	Total Gas (ppm)	**139677**	99578	115349	118552
	Total Combustible Gas (ppm)	**29**	74	48	50
D1533	Moisture (ppm)	**29**	20	4	5
D971	Interfacial Tension (dynes/cm)	**36.2**	35.4	40.2	37.9
D974	Acid Number (mg KOH/g)	**0.001**	<0.02	0.005	0.013
D1500	Color Number	**1.0**	0.5	<1.5	L1.5
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**23**	20	34	30
D924	Power Factor (% at 25 ºC)	**0.010**	0.010	0.004	0.004
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.050**	0.060	0.073	0.060
D1298	Specific Gravity	**0.855**	0.852	0.852	0.850
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**2.3**	1.19	1.32	1.58
	Degree of Polymerization	**937**	1000	930	937
	Estimated % Life Remaining	**100**	100	100	100

Interpretation: ***Moisture (29 ppm) is questionable. All other oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.05%) is depleted. Furans DP is 937. PCB is reported as 2.3 ppm.***

Recommendation: ***Continue sampling on an annual basis. Consider conducting a Re-inhibit Treatment to restore oxidation inhibitor and extend the serviceable life of the oil.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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22-Jun-23

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Unit ID	**Mill Gate**	Power Rating (MVA)	**2.0**
Serial Number	**261784**	Voltage	**12kV**
Location	**Iroquois Falls**	Fluid Volume	**1420 Imp Gal**
Manufacturer	**Ferranti-Packard**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1955**	Preservation	**Conservator**

	Sample Date	**25-Apr-23**	25-May-22	4-May-21	13-May-20
	Laboratory No.	**1764**	214	5073549	5070240
	Container No.	**36976**	36009	48593	45849
	Temperature (ºC)	**15**	30	34	25
H_2	Hydrogen (ppm)	**1**	8	14	13
CH_4	Methane (ppm)	**<1**	6	3	3
C_2H_6	Ethane (ppm)	**<1**	3	2	<1
C_2H_4	Ethylene (ppm)	**3**	8	8	2
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**45**	289	276	190
CO_2	Carbon dioxide (ppm)	**1579**	2982	2469	1740
N_2	Nitrogen (ppm)	**96199**	77907	83010	82502
O_2	Oxygen (ppm)	**34758**	11922	29567	30897
	Total Gas (ppm)	**132585**	93125	115349	115347
	Total Combustible Gas (ppm)	**49**	314	303	208
D1533	Moisture (ppm)	**15**	23	9	6
D971	Interfacial Tension (dynes/cm)	**26.3**	26.0	28.4	27.2
D974	Acid Number (mg KOH/g)	**0.024**	0.040	0.045	0.050
D1500	Color Number	**1.0**	<1.5	<1.5	L1.5
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**19**	24	29	29
D924	Power Factor (% at 25 ºC)	**0.022**	0.025	0.024	0.005
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.090**	0.100	0.132	0.066
D1298	Specific Gravity	**0.865**	0.865	0.865	0.862
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**2.3**	1.18	1.37	1.61
	Degree of Polymerization	**622**	634	633	656
	Estimated % Life Remaining	**82**	83	83	86

Interpretation: ***Interfacial tension (26.3 dynes/cm) is questionable. All other oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.09%) is depleted. Furans DP is 622. PCB is reported as 2.3 ppm.***

Recommendation: ***Continue sampling on an annual basis. If oxidation inhibitor is added, we would recommend first conducting a reclamation treatment to improve oil quality properties. Furan results reflect a paper condition better than actual as the recent oil replacement has removed some furan from the unit.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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22-Jun-23

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Unit ID	**Kapuskasing**	Power Rating (MVA)	**5.0**
Serial Number	**1-2086**	Voltage	**25kV/4.16kV**
Location	**Kapuskasing**	Fluid Volume	**990 Imp Gal**
Manufacturer	**Ferranti-Packard**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1963**	Preservation	**Conservator**

	Sample Date	**20-Apr-23**	24-May-22	3-May-21	13-May-20
	Laboratory No.	**1703**	223	5073574	5070249
	Container No.	**38398**	36065	48577	45858
	Temperature (ºC)	**20**	35	19	20
H_2	Hydrogen (ppm)	**12**	17	14	12
CH_4	Methane (ppm)	**<1**	12	2	10
C_2H_6	Ethane (ppm)	**<1**	2	1	6
C_2H_4	Ethylene (ppm)	**62**	27	12	57
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**519**	481	349	99
CO_2	Carbon dioxide (ppm)	**3465**	2445	1753	1962
N_2	Nitrogen (ppm)	**92960**	90708	91516	72787
O_2	Oxygen (ppm)	**35621**	5683	21700	34008
	Total Gas (ppm)	**132639**	99375	115347	108941
	Total Combustible Gas (ppm)	**593**	539	378	184
D1533	Moisture (ppm)	**16**	24	7	8
D971	Interfacial Tension (dynes/cm)	**25.0**	23.7	21.1	22.2
D974	Acid Number (mg KOH/g)	**0.042**	0.090	0.093	0.093
D1500	Color Number	**2.5**	<3.0	<3.0	L3.0
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**38**	22	35	36
D924	Power Factor (% at 25 ºC)	**0.116**	0.084	0.005	0.021
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.100**	0.010	<0.010	<0.010
D1298	Specific Gravity	**0.880**	0.880	0.878	0.875
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**12.9**	11.92	13.31	13.97
	Degree of Polymerization	**789**	781	720	785
	Estimated % Life Remaining	**99**	98	100	100

Interpretation: ***Ethylene (62 ppm) and carbon monoxide (519 ppm) are slightly elevated. Interfacial tension (25 dynes/cm) and power factor (0.116% at 25C) are questionable. All other oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.10%) is effective. Furans DP is 789. PCB is reported as 12.9 ppm.***

Recommendation: ***Oil quality properties suggest that oil oxidation is advanced. Acidic oxidation by-products will ultimately accelerate the aging of the paper insulation and shorten the life of the unit. We recommend conducting an Oil Reclamation Treatment to restore oil quality properties to acceptable limits.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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22-Jun-23

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Unit ID	**Main Station TX1**	Power Rating (MVA)	**7.5**
Serial Number	**288692**	Voltage	**115kV/24.94kV**
Location	**Cochrane**	Fluid Volume	**3095 Imp Gal**
Manufacturer	**CGE**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1975**	Preservation	**Conservator**

	Sample Date	**20-Apr-23**	24-May-22	3-May-21	13-May-20
	Laboratory No.	**1705**	224	5073558	5070241
	Container No.	**39115**	36081	48587	45857
	Temperature (ºC)	**25**	35	23	20
H_2	Hydrogen (ppm)	**5**	8	9	7
CH_4	Methane (ppm)	**<1**	3	2	3
C_2H_6	Ethane (ppm)	**<1**	1	<1	<1
C_2H_4	Ethylene (ppm)	**20**	11	8	7
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**382**	334	215	177
CO_2	Carbon dioxide (ppm)	**2533**	1990	1361	1321
N_2	Nitrogen (ppm)	**96779**	78377	81961	86787
O_2	Oxygen (ppm)	**36936**	7261	31792	36658
	Total Gas (ppm)	**136655**	87985	115348	124960
	Total Combustible Gas (ppm)	**407**	357	234	194
D1533	Moisture (ppm)	**2**	6	14	4
D971	Interfacial Tension (dynes/cm)	**30.4**	20.5	31.0	29.3
D974	Acid Number (mg KOH/g)	**0.008**	0.030	0.030	0.043
D1500	Color Number	**<0.5**	<1.5	<2.0	L1.5
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**39**	13	35	30
D924	Power Factor (% at 25 ºC)	**0.192**	0.032	0.078	0.016
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.100**	0.010	<0.010	<0.010
D1298	Specific Gravity	**0.858**	0.859	0.861	0.855
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**36.0**	33.54	33.52	48.85
	Degree of Polymerization	**884**	923	900	905
	Estimated % Life Remaining	**100**	100	100	100

Interpretation: ***All oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.100%) is effective. Furans DP is 884. PCB is reported as 36 ppm.***

Recommendation: ***We recommend retrofilling with Type II mineral oil (oxidation inhibitor 0.3%).***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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Unit ID	**Main Station TX1 TC**	Power Rating (MVA)	**7.5**
Serial Number	**288692**	Voltage	**115kV/24.94kV**
Location	**Cochrane**	Fluid Volume	**165 Imp Gal**
Manufacturer	**CGE**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1975**	Preservation	

	Sample Date	**20-Apr-23**	24-May-22	3-May-21	13-May-20
	Laboratory No.	**1706**	220	5073559	5070252
	Container No.	**39162**	36106	48579	45857
	Temperature (ºC)	**25**	35		
H_2	Hydrogen (ppm)	**151**	61	47	101
CH_4	Methane (ppm)	**28**	21	7	8
C_2H_6	Ethane (ppm)	**5**	7	3	1
C_2H_4	Ethylene (ppm)	**88**	87	44	17
C_2H_2	Acetylene (ppm)	**582**	493	313	133
CO	Carbon monoxide (ppm)	**156**	54	213	133
CO_2	Carbon dioxide (ppm)	**1600**	1297	1086	848
N_2	Nitrogen (ppm)	**96031**	102143	87978	91582
O_2	Oxygen (ppm)	**35509**	29243	25658	32138
	Total Gas (ppm)	**134150**	133406	115349	124961
	Total Combustible Gas (ppm)	**1010**	723	627	393
D1533	Moisture (ppm)	**155**	23	12	14
D971	Interfacial Tension (dynes/cm)	**18.0**	17.9	20.5	19.9
D974	Acid Number (mg KOH/g)	**0.313**	0.560	0.511	0.523
D1500	Color Number	**<3.5**	3.5	<3.0	L4.0
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear w/ part.	Clear/Part.
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**31**	15	35	20
D924	Power Factor (% at 25 ºC)	**0.188**	0.146	0.159	0.014
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)				
D1298	Specific Gravity	**0.862**	0.863	0.862	0.860
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**41.9**	56.48	57.96	56.90
	Degree of Polymerization				
	Estimated % Life Remaining				

Interpretation: ***Moisture (155 ppm), interfacial tension (18 dynes/cm) and acid number (0.313 mg KOH/g) are unacceptable. All other oil quality properties and dissolved gas levels are within acceptable limits. PCB is reported as 41.9 ppm.***

Recommendation: ***We recommend conducting a Retrofill Treatment to restore oil quality properties to acceptable limits.***

Oil Diagnostics Report

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Unit ID	**Main Station TX2**	Power Rating (MVA)	**7.5**
Serial Number	**288693**	Voltage	**115kV/24.94kV**
Location	**Cochrane**	Fluid Volume	**3095 Imp Gal**
Manufacturer	**CGE**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1975**	Preservation	**Conservator**

	Sample Date	**20-Apr-23**	24-May-22	3-May-21	13-May-20
	Laboratory No.	**1707**	226	5073548	5070239
	Container No.	**37486**	36039	48596	45864
	Temperature (ºC)	**25**	35	22	20
H_2	Hydrogen (ppm)	**11**	4	9	5
CH_4	Methane (ppm)	**<1**	3	2	1
C_2H_6	Ethane (ppm)	**<1**	1	<1	<1
C_2H_4	Ethylene (ppm)	**37**	20	11	7
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**659**	367	333	261
CO_2	Carbon dioxide (ppm)	**3284**	2216	1694	1383
N_2	Nitrogen (ppm)	**93320**	79815	85671	78855
O_2	Oxygen (ppm)	**33831**	15670	30832	34837
	Total Gas (ppm)	**131142**	98096	118552	115349
	Total Combustible Gas (ppm)	**707**	395	355	274
D1533	Moisture (ppm)	**7**	2	6	8
D971	Interfacial Tension (dynes/cm)	**30.2**	33.7	32.8	31.1
D974	Acid Number (mg KOH/g)	**0.004**	0.020	0.022	0.029
D1500	Color Number	**<0.5**	<1.5	<1.5	L1.5
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**35**	28	31	35
D924	Power Factor (% at 25 ºC)	**0.016**	0.006	0.003	0.003
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.330**	0.260	0.271	0.331
D1298	Specific Gravity	**0.855**	0.858	0.860	0.856
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**9.3**	6.28	6.34	12.46
	Degree of Polymerization	**953**	953	961	961
	Estimated % Life Remaining	**100**	100	100	100

Interpretation: ***Carbon monoxide (659 ppm) is slightly elevated. All other oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.33%) is effective. Furans DP is 953. PCB is reported as 9.3 ppm.***

Recommendation: ***Continue sampling on an annual basis.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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22-Jun-23

Toll Free: 1-877-875-2775 Fax: (902) 755-2949

Unit ID	**Main Station TX2 TC**	Power Rating (MVA)	**7.5**
Serial Number	**288693**	Voltage	**115kV/24.94kV**
Location	**Cochrane**	Fluid Volume	**165 Imp Gal**
Manufacturer	**CGE**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1975**	Preservation	**Conservator**

	Sample Date	**20-Apr-23**	24-May-22	3-May-21	13-May-20
	Laboratory No.	**1708**	215	5073560	5070251
	Container No.	**39813**	36064	48588	45859
	Temperature (ºC)	**25**	35	22	
H_2	Hydrogen (ppm)	**92**	99	124	33
CH_4	Methane (ppm)	**31**	24	9	8
C_2H_6	Ethane (ppm)	**4**	2	2	<1
C_2H_4	Ethylene (ppm)	**67**	49	35	12
C_2H_2	Acetylene (ppm)	**593**	379	265	125
CO	Carbon monoxide (ppm)	**14**	59	26	6
CO_2	Carbon dioxide (ppm)	**1255**	730	547	470
N_2	Nitrogen (ppm)	**86209**	74995	79534	81357
O_2	Oxygen (ppm)	**39413**	22739	34807	39745
	Total Gas (ppm)	**127678**	99076	115349	121756
	Total Combustible Gas (ppm)	**801**	612	461	184
D1533	Moisture (ppm)	**7**	1	13	15
D971	Interfacial Tension (dynes/cm)	**37.0**	37.0	39.9	38.8
D974	Acid Number (mg KOH/g)	**0.006**	<0.02	0.006	0.011
D1500	Color Number	**<2.5**	<1.5	<1.5	L2.5
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear w/ part.	Clear/Part.
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**27**	22	29	26
D924	Power Factor (% at 25 ºC)	**0.017**	0.016	0.004	0.020
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)				
D1298	Specific Gravity	**0.870**	0.870	0.870	0.868
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**<1**	ND	<1.0	<1.0
	Degree of Polymerization				
	Estimated % Life Remaining				

Interpretation: ***All oil quality properties and dissolved gas levels are within acceptable limits. PCB is reported as <1 ppm.***

Recommendation: ***Continue sampling on an annual basis.***

Oil Diagnostics Report

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22-Jun-23

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Unit ID	**Cochrane Regulator**	Power Rating (MVA)	**5.2**
Serial Number	**269579**	Voltage	**4.16kV**
Location	**Cochrane**	Fluid Volume	**588 Imp Gal**
Manufacturer	**Ferranti-Packard**	Fluid Type	**Mineral Oil**
Year of Manufacture		Preservation	**Sealed**

	Sample Date	**20-Apr-23**	24-May-22	3-May-21	13-May-20
	Laboratory No.	**1709**	218	5073547	5070238
	Container No.	**38652**	36005	48590	45852
	Temperature (ºC)	**20**	30	22	20
H_2	Hydrogen (ppm)	**42**	56	30	17
CH_4	Methane (ppm)	**1**	2	2	1
C_2H_6	Ethane (ppm)	**2**	1	<1	<1
C_2H_4	Ethylene (ppm)	**3**	3	2	2
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**20**	56	20	12
CO_2	Carbon dioxide (ppm)	**1832**	1275	927	765
N_2	Nitrogen (ppm)	**93486**	77854	73811	83322
O_2	Oxygen (ppm)	**32285**	21249	34149	37638
	Total Gas (ppm)	**127671**	100496	108941	121757
	Total Combustible Gas (ppm)	**68**	118	54	32
D1533	Moisture (ppm)	**11**	28	5	7
D971	Interfacial Tension (dynes/cm)	**29.7**	28.6	32.2	32.3
D974	Acid Number (mg KOH/g)	**0.009**	0.030	0.024	0.026
D1500	Color Number	**<1.0**	1.0	<1.5	L1.5
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**33**	23	34	29
D924	Power Factor (% at 25 ºC)	**0.031**	0.034	0.001	0.012
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.170**	0.100	0.132	0.132
D1298	Specific Gravity	**0.865**	0.866	0.865	0.861
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**5.0**	3.24	3.45	3.63
	Degree of Polymerization	**587**	611	624	657
	Estimated % Life Remaining	**78**	81	100	86

Interpretation: ***Interfacial tension (29.7 dynes/cm) is questionable. All other oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.17%) is effective. Furans DP is 587. PCB is reported as 5 ppm.***

Recommendation: ***Continue sampling on an annual basis. Furan results reflect a paper insulation condition better than actual as the recent oil replacement has removed some furan from the unit.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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Unit ID	**Cochrane Reg TC**	Power Rating (MVA)	**5.2**
Serial Number	**269579**	Voltage	**4.16kV**
Location	**Cochrane**	Fluid Volume	**72 Imp Gal**
Manufacturer	**Ferranti-Packard**	Fluid Type	**Mineral Oil**
Year of Manufacture		Preservation	

	Sample Date	**20-Apr-23**	24-May-22	3-May-21	13-May-20
	Laboratory No.	**1710**	219	5073561	5070250
	Container No.	**IFZ514**	36027	48582	45845
	Temperature (ºC)	**20**	30	22	
H_2	Hydrogen (ppm)	**5**	3	9	1
CH_4	Methane (ppm)	**2**	3	2	1
C_2H_6	Ethane (ppm)	**3**	1	1	<1
C_2H_4	Ethylene (ppm)	**66**	13	20	1
C_2H_2	Acetylene (ppm)	**69**	33	53	<1
CO	Carbon monoxide (ppm)	**24**	98	37	9
CO_2	Carbon dioxide (ppm)	**1485**	991	727	573
N_2	Nitrogen (ppm)	**94704**	87027	82960	83862
O_2	Oxygen (ppm)	**44829**	21887	34744	40515
	Total Gas (ppm)	**141154**	110056	118553	124962
	Total Combustible Gas (ppm)	**136**	151	122	12
D1533	Moisture (ppm)	**7**	6	15	13
D971	Interfacial Tension (dynes/cm)	**32.7**	32.2	38.7	37.4
D974	Acid Number (mg KOH/g)	**0.001**	<0.02	0.011	0.016
D1500	Color Number	**<1.5**	1.5	<2.0	L1.5
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear w/ part.	Clear/Part.
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**20**	25	34	29
D924	Power Factor (% at 25 ºC)	**0.053**	0.046	0.056	0.070
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)				
D1298	Specific Gravity	**0.865**	0.866	0.864	0.861
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**10.8**	7.67	9.85	9.34
	Degree of Polymerization				
	Estimated % Life Remaining				

Interpretation: ***Dielectric breakdown voltage (20 kV) is questionable. All other quality properties and dissolved gas levels are within acceptable limits. PCB is reported as 10.8 ppm.***

Recommendation: ***Continue sampling on an annual basis.***

Oil Diagnostics Report

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22-Jun-23

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Unit ID	**T1A**	Power Rating (MVA)	**1.0**
Serial Number	**203109**	Voltage	**110kV/2.4kV**
Location	**Cochrane**	Fluid Volume	**1225 Imp Gal**
Manufacturer	**English Electric Co.**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1953**	Preservation	**Conservator**

	Sample Date	**25-Apr-23**	24-May-22	3-May-21	13-May-20
	Laboratory No.	**1766**	213	5073557	5070247
	Container No.	**38697**	36019	48595	45855
	Temperature (ºC)	**20**	35	30	20
H_2	Hydrogen (ppm)	**5**	12	15	15
CH_4	Methane (ppm)	**4**	5	3	3
C_2H_6	Ethane (ppm)	**6**	3	1	<1
C_2H_4	Ethylene (ppm)	**7**	5	5	2
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**140**	285	135	135
CO_2	Carbon dioxide (ppm)	**2557**	2703	1868	1637
N_2	Nitrogen (ppm)	**93091**	86945	89529	85326
O_2	Oxygen (ppm)	**41141**	4044	30199	37843
	Total Gas (ppm)	**136951**	94002	121755	124961
	Total Combustible Gas (ppm)	**162**	310	159	155
D1533	Moisture (ppm)	**25**	10	8	7
D971	Interfacial Tension (dynes/cm)	**24.8**	23.1	22.0	21.4
D974	Acid Number (mg KOH/g)	**0.049**	0.100	0.089	0.102
D1500	Color Number	**1.5**	<2.0	<2.0	L2.0
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**29**	11	36	29
D924	Power Factor (% at 25 ºC)	**0.110**	0.265	0.011	0.034
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.020**	0.030	0.017	<0.010
D1298	Specific Gravity	**0.848**	0.848	0.848	0.845
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**3.2**	3.11	3.35	3.86
	Degree of Polymerization	**751**	765	755	785
	Estimated % Life Remaining	**95**	97	96	99

Interpretation: ***Moisture (25 ppm), interfacial tension (24.8 dynes/cm), and power factor (0.110% at 25C) are questionable. All other oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.02%) is depleted. Furans DP is 751. PCB is reported as 3.2 ppm.***

Recommendation: ***Interfacial tension suggests that oil oxidation is advanced. Acidic oxidation by-products will ultimately accelerate the aging of the paper insulation and shorten the life of the unit. We recommend conducting an Oil Reclamation Treatment to restore oil quality properties to acceptable limits.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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22-Jun-23

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Unit ID	**T1B**	Power Rating (MVA)	**1.0**
Serial Number	**203108**	Voltage	**110kV/2.4kV**
Location	**Cochrane**	Fluid Volume	**1225 Imp Gal**
Manufacturer	**English Electric Co.**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1953**	Preservation	**Conservator**

	Sample Date	**25-Apr-23**	24-May-22	3-May-21	13-May-20
	Laboratory No.	**1763**	227	5073552	5070245
	Container No.	**37050**	36047	48581	45860
	Temperature (ºC)	**20**	35	30	25
H_2	Hydrogen (ppm)	**8**	13	14	2
CH_4	Methane (ppm)	**<1**	4	2	2
C_2H_6	Ethane (ppm)	**4**	2	1	<1
C_2H_4	Ethylene (ppm)	**8**	8	5	3
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**176**	303	224	138
CO_2	Carbon dioxide (ppm)	**2830**	2571	1856	1340
N_2	Nitrogen (ppm)	**95644**	84939	85159	82522
O_2	Oxygen (ppm)	**44296**	8064	28087	34547
	Total Gas (ppm)	**142966**	95904	115348	118554
	Total Combustible Gas (ppm)	**196**	330	246	145
D1533	Moisture (ppm)	**12**	13	6	6
D971	Interfacial Tension (dynes/cm)	**25.9**	23.7	21.6	21.3
D974	Acid Number (mg KOH/g)	**0.050**	0.100	0.096	0.111
D1500	Color Number	**<1.5**	1.5	<2.0	L2.0
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**26**	33	36	34
D924	Power Factor (% at 25 ºC)	**0.078**	0.136	0.005	0.032
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.090**	0.050	0.020	<0.010
D1298	Specific Gravity	**0.848**	0.860	0.850	0.845
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**5.6**	4.73	4.76	5.50
	Degree of Polymerization	**658**	686	683	705
	Estimated % Life Remaining	**86**	89	89	91

Interpretation: ***Interfacial tension (25.9 dynes/cm) is questionable. All other oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.09%) is depleted. Furans DP is 658. PCB is reported as 5.6 ppm.***

Recommendation: ***Interfacial tension suggests that oil oxidation is advanced. Acidic oxidation by-products will ultimately accelerate the aging of the paper insulation and shorten the life of the unit. We recommend conducting an Oil Reclamation Treatment to restore oil quality properties to acceptable limits.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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22-Jun-23

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Unit ID	**T1C**	Power Rating (MVA)	**1.0**
Serial Number	**203107**	Voltage	**110kV/2.4kV**
Location	**Cochrane**	Fluid Volume	**1225 Imp Gal**
Manufacturer	**English Electric Co.**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1953**	Preservation	**Conservator**

	Sample Date	**20-Apr-23**	24-May-22	3-May-21	13-May-20
	Laboratory No.	**1704**	216	5073554	5070246
	Container No.	**38407**	36103	48589	45853
	Temperature (ºC)	**20**	35	30	23
H_2	Hydrogen (ppm)	**12**	15	10	14
CH_4	Methane (ppm)	**1**	5	1	2
C_2H_6	Ethane (ppm)	**4**	3	1	<1
C_2H_4	Ethylene (ppm)	**8**	7	7	4
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**286**	294	199	142
CO_2	Carbon dioxide (ppm)	**3692**	2616	1976	1711
N_2	Nitrogen (ppm)	**95755**	85913	86038	82872
O_2	Oxygen (ppm)	**40187**	7535	30321	37012
	Total Gas (ppm)	**139945**	96388	118553	121757
	Total Combustible Gas (ppm)	**311**	324	218	162
D1533	Moisture (ppm)	**5**	7	7	4
D971	Interfacial Tension (dynes/cm)	**30.2**	23.6	21.2	20.9
D974	Acid Number (mg KOH/g)	**0.046**	0.090	0.098	0.119
D1500	Color Number	**<2.0**	<2.0	<2.0	L2.5
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**35**	10	36	35
D924	Power Factor (% at 25 ºC)	**0.094**	0.133	0.019	0.009
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.100**	0.020	<0.010	<0.010
D1298	Specific Gravity	**0.865**	0.845	0.848	0.846
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**4.3**	4.04	4.23	4.49
	Degree of Polymerization	**654**	660	656	682
	Estimated % Life Remaining	**86**	86	86	88

Interpretation: ***All oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.10%) is effective. Furans DP is 654. PCB is reported as 4.3 ppm.***

Recommendation: ***Continue sampling on an annual basis.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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22-Jun-23

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Unit ID	**T2A**	Power Rating (MVA)	**1.0**
Serial Number	**286604**	Voltage	**115kV**
Location	**Cochrane**	Fluid Volume	**1225 Imp Gal**
Manufacturer	**English Electric Co.**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1960**	Preservation	**Conservator**

	Sample Date	**25-Apr-23**	24-May-22	4-May-21	13-May-20
	Laboratory No.	**1770**	217	5073556	5070244
	Container No.	**37115**	36076	48597	45851
	Temperature (ºC)	**15**	37	25	25
H_2	Hydrogen (ppm)	**2**	<1	4	4
CH_4	Methane (ppm)	**<1**	2	1	1
C_2H_6	Ethane (ppm)	**<1**	<1	<1	<1
C_2H_4	Ethylene (ppm)	**3**	3	1	1
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**51**	87	60	50
CO_2	Carbon dioxide (ppm)	**2024**	4104	1097	956
N_2	Nitrogen (ppm)	**49888**	71413	75657	79758
O_2	Oxygen (ppm)	**26892**	22267	35323	37781
	Total Gas (ppm)	**78860**	95176	112143	118551
	Total Combustible Gas (ppm)	**56**	92	66	56
D1533	Moisture (ppm)	**1**	10	5	8
D971	Interfacial Tension (dynes/cm)	**38.7**	31.5	32.7	30.2
D974	Acid Number (mg KOH/g)	**0.011**	0.030	0.023	0.035
D1500	Color Number	**<1.5**	<1.5	<2.0	L2.0
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**45**	23	33	35
D924	Power Factor (% at 25 ºC)	**0.028**	0.011	0.020	0.004
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.050**	0.050	0.066	0.066
D1298	Specific Gravity	**0.875**	0.880	0.877	0.875
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**21.6**	17.92	23.39	24.36
	Degree of Polymerization	**624**	653	637	658
	Estimated % Life Remaining	**82**	85	84	86

Interpretation: ***All oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.05%) is depleted. Furans DP is 624. PCB is reported as 21.6 ppm.***

Recommendation: ***Continue sampling on an annual basis. Consider retrofilling with inhibited oil and reduce PCB content.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

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22-Jun-23

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Unit ID	**T2B**	Power Rating (MVA)	**1.0**
Serial Number	**272423**	Voltage	**115kV**
Location	**Cochrane**	Fluid Volume	**1225 Imp Gal**
Manufacturer	**English Electric Co.**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1959**	Preservation	**Conservator**

	Sample Date	**25-Apr-23**	24-May-22	4-May-21	13-May-20
	Laboratory No.	**1767**	225	5073550	5070242
	Container No.	**38891**	36102	48584	45863
	Temperature (ºC)	**20**	35	28	20
H_2	Hydrogen (ppm)	**24**	<1	2	1
CH_4	Methane (ppm)	**<1**	2	1	1
C_2H_6	Ethane (ppm)	**<1**	<1	<1	<1
C_2H_4	Ethylene (ppm)	**4**	2	4	2
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**44**	92	58	48
CO_2	Carbon dioxide (ppm)	**1669**	1514	1030	993
N_2	Nitrogen (ppm)	**89284**	73639	82345	83916
O_2	Oxygen (ppm)	**47673**	23219	35112	40000
	Total Gas (ppm)	**138698**	98468	118552	124961
	Total Combustible Gas (ppm)	**72**	96	65	52
D1533	Moisture (ppm)	**15**	9	5	9
D971	Interfacial Tension (dynes/cm)	**32.7**	33.0	31.7	32.1
D974	Acid Number (mg KOH/g)	**0.022**	0.020	0.028	0.027
D1500	Color Number	**1.0**	<1.5	<2.0	L2.0
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**25**	22	33	32
D924	Power Factor (% at 25 ºC)	**0.026**	0.013	0.002	0.003
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.050**	0.050	0.065	0.063
D1298	Specific Gravity	**0.870**	0.870	0.871	0.867
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**16.2**	16.00	19.91	19.86
	Degree of Polymerization	**729**	732	724	727
	Estimated % Life Remaining	**93**	94	93	93

Interpretation: ***All oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.05%) is depleted. Furans DP is 729. PCB is reported as 16.2 ppm.***

Recommendation: ***Continue sampling on an annual basis. Consider retrofilling with inhibited oil and reduce PCB content.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Oil Diagnostics Report

Dan Boucher
Northern Ontario Wires
153 Sixth Ave
Cochrane, ON P0L 1C0

Stark International Inc.
113 Archimedes Street
New Glasgow, Nova Scotia
B2H 2T3

22-Jun-23

Toll Free: 1-877-875-2775 Fax: (902) 755-2949

Unit ID	**T2C**	Power Rating (MVA)	**1.0**
Serial Number	**258423**	Voltage	**115kV**
Location	**Cochrane**	Fluid Volume	**1225 Imp Gal**
Manufacturer	**English Electric Co.**	Fluid Type	**Mineral Oil**
Year of Manufacture	**1957**	Preservation	**Conservator**

	Sample Date	**25-Apr-23**	24-May-22	4-May-21	13-May-20
	Laboratory No.	**1769**	221	5073553	5070243
	Container No.	**36967**	36034	48578	45848
	Temperature (ºC)	**15**	35		25
H_2	Hydrogen (ppm)	**3**	<1	12	2
CH_4	Methane (ppm)	**<1**	2	1	1
C_2H_6	Ethane (ppm)	**5**	1	<1	<1
C_2H_4	Ethylene (ppm)	**11**	3	2	2
C_2H_2	Acetylene (ppm)	**<1**	<1	<1	<1
CO	Carbon monoxide (ppm)	**236**	99	68	50
CO_2	Carbon dioxide (ppm)	**3443**	1375	1003	913
N_2	Nitrogen (ppm)	**51320**	70709	78164	83526
O_2	Oxygen (ppm)	**25313**	24638	36098	40465
	Total Gas (ppm)	**80331**	96827	115348	124959
	Total Combustible Gas (ppm)	**255**	105	83	55
D1533	Moisture (ppm)	**22**	2	9	6
D971	Interfacial Tension (dynes/cm)	**33.1**	31.5	30.6	30.8
D974	Acid Number (mg KOH/g)	**0.012**	0.030	0.032	0.033
D1500	Color Number	**<1.5**	<1.5	<2.0	L1.5
D1524	Visual Examination	**Clear & Bright**	Clear & Bright	Clear & Bright	Clear/Bright
D877	Dielectric BV (kV)				
D1816 1mm	Dielectric BV (kV)	**18**	16	34	28
D924	Power Factor (% at 25 ºC)	**0.020**	0.014	0.042	0.021
D924	Power Factor (% at 100 ºC)				
D2668	Oxidation Inhibitor (%)	**0.050**	0.050	0.066	0.064
D1298	Specific Gravity	**0.878**	0.871	0.869	0.868
D88	Viscosity (SUS)				
D97	Pour Point (ºC)				
D92	Flash Point (ºC)				
D92	Fire Point (ºC)				
D1807	Refractive Index				
D1275	Corrosive Sulfur				
	PCB Content (ppm)	**6.0**	2.78	3.20	7.36
	Degree of Polymerization	**862**	875	859	871
	Estimated % Life Remaining	**100**	100	100	100

Interpretation: ***Moisture (22 ppm) is questionable. All other oil quality properties and dissolved gas levels are within acceptable limits. Oxidation inhibitor (0.05%) is depleted. Furans DP is 862. PCB is reported as 6 ppm.***

Recommendation: ***We recommend resampling to verify dielectric breakdown voltage. Consider retrofilling with inhibited oil and reduce PCB content.***

(* Furans results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.)

Appendix D-8

2023 Transformer Fleet Assessment Report

2023 Transformer Fleet Assessment Report

Prepared For:
Dan Boucher
Northern Ontario Wires
153 Sixth Ave
Cochrane, ON
P0L 1C0

Submitted By:
STARK International
113 Archimedes Street
New Glasgow, NS
B2H 2T3

Submission Date:
June 22, 2023

113 Archimedes Street
New Glasgow, Nova Scotia
B2H 2T3

June 22, 2023

Dan Boucher
Northern Ontario Wires
153 Sixth Ave
Cochrane, ON
P0L 1C0

RE: Transformer Fleet Assessment Report

Mr. Boucher:

STARK has reviewed the laboratory analysis results for 16 samples drawn in April of 2023 for Northern Ontario Wires. We are pleased to provide you with this assessment report containing our maintenance recommendations and brief diagnostic summary for each unit.

For your convenience, we present the following prioritized list of recommendations:

1. Resample for dielectric breakdown voltage:

    Iroquois Falls, Cambridge St, SN: 305235
    Cochrane T2C, SN: 258423

2. Conduct an Oil Reclamation Treatment (or Retrofill Treatment to also reduce PCB content) on the following units to improve oil quality properties and extend reliable life:

    Kapuskasing, SN: 1-2086
    Cochrane T1A, SN: 203109
    Cochrane T1B, SN: 203108

3. Replace the oil in the following units to restore oil quality properties to acceptable limits and to reduce PCB content:

    Cochrane Main Station TX1 TC, SN: 288692

4. Consider conducting a light reclamation and adding oxidation inhibitor:

    Iroquois Falls, Mill Gate, SN: 261784

5. Consider conducting a Re-inhibit Treatment to restore oxidation inhibitor in the following unit:

    Iroquois Falls, Detroyes, SN: 1-2577

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6. The following units have low oxidation inhibitor but also mildly oxidized oil. Oil maintenance by retrofill is optional to improve oil quality properties, replenish oxidation inhibitor, and reduce PCB content:

   Cochrane T2A, SN: 286604
   Cochrane T2B, SN: 272423
   Cochrane T2C, SN: 258423

7. Consider retrofilling the following units solely to reduce the PCB below 2 ppm:

   Cochrane Main Station TX1, SN: 288692
   Cochrane Main Station TX2, SN: 288693
   Cochrane Regulator, SN: 269579
   Cochrane Regulator TC, SN: 269579

8. Continue sampling the following units on an annual basis:

   Iroquois Falls, Detroyes, SN: 1-2577
   Iroquois Falls, Mill Gate, SN: 261784
   Cochrane Main Station TX2, SN: 288693
   Cochrane Main Station TX2 TC, SN: 288693
   Cochrane Regulator, SN: 269579
   Cochrane Regulator TC, SN: 269579
   Cochrane T1C, SN: 203107
   Cochrane T2A, SN: 286604
   Cochrane T2B, SN: 272423

9. The Visual Inspection identified the following concerns:

   a) Oil stains (leaks)

   Iroquois Falls, Detroyes, SN: 1-2577 top lid, tap changer, bushing box, and bottom of conservator
   Iroquois Falls, Mill Gate, SN: 261784 top lid, bushing cabinet, tap changer, and the level gauge
   Kapuskasing, SN: 2086 temperature probe
   Cochrane Regulator, SN: 269579 level gauge, explosion vent
   Cochrane T1A, SN: 203109 top lid and/or temperature gauge
   Cochrane T1B, SN: 203108 top lid or bushing
   Cochrane T1C, SN: 203107 top lid (or bushing) and conservator valve
   Cochrane T2C, SN: 258423 temperature gauge

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b) Low oil level reading

Iroquois Falls, Detroyes, SN: 1-2577
Cochrane T1C, SN: 203107

c) Slightly low oil level reading

Iroquois Falls, Mill Gate, SN: 261784
Cochrane T1B, SN: 203108

d) Level gauge needs replacement

Kapuskasing, SN: 2086

e) Temp gauge needs replacement

Cochrane T1A, SN: 203109

f) Water in the tap changer level gauge

Cochrane Regulator, SN: 269579

g) Oil in the level gauge

Cochrane Regulator, SN: 269579

h) Rust

Kapuskasing, SN: 2086

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Stark International

Diagnostic Summaries

Furan results are specific for the sample submitted and assume the unit has not been subjected to reclamation and/or retro-fill treatments.

Iroquois Falls, Cambridge St, SN: 305235

Carbon monoxide (892 ppm) is slightly elevated.
Power factor (0.618% at 25°C) and dielectric breakdown voltage (18 kV) are unacceptable.
All other oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.120%) is effective.
Furans DP is 937.
PCB is reported as <1 ppm.

Interpretation and Recommendation

Resample to verify dielectric breakdown voltage.

Visual Inspection

The Visual Inspection did not identify any areas of concern.

Iroquois Falls, Detroyes, SN: 1-2577

Moisture (29 ppm) is questionable.
All other oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.05%) is depleted.
Furans DP is 937.
PCB is reported as 2.3 ppm.

Interpretation and Recommendation

Continue sampling on an annual basis.

Consider conducting a Re-inhibit Treatment to restore oxidation inhibitor and extend the serviceable life of the oil.

Visual Inspection

The Visual Inspection identified a low oil level reading and leaks from the top lid, tap changer, bushing box, and bottom of conservator.

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Iroquois Falls, Mill Gate, SN: 261784

Interfacial tension (26.3 dynes/cm) is questionable.
All other oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.09%) is depleted.
Furans DP is 622.
PCB is reported as 2.3 ppm.

Interpretation and Recommendation

Continue sampling on an annual basis.

If oxidation inhibitor is added, we would recommend first conducting a reclamation treatment to improve oil quality properties.

Furan results reflect a paper condition better than actual as the recent oil replacement has removed some furan from the unit.

Visual Inspection

The Visual Inspection identified a slightly low oil level reading, and leaks from the top lid, bushing cabinet, tap changer, and the level gauge.

Kapuskasing, SN: 1-2086

Ethylene (62 ppm) and carbon monoxide (519 ppm) are slightly elevated.
Interfacial tension (25 dynes/cm) and power factor (0.116% at 25C) are questionable.
All other oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.10%) is effective.
Furans DP is 789.
PCB is reported as 12.9 ppm.

Interpretation and Recommendation

Oil quality properties suggest that oil oxidation is advanced. Acidic oxidation by-products will ultimately accelerate the aging of the paper insulation and shorten the life of the unit.

We recommend conducting an Oil Reclamation Treatment to restore oil quality properties to acceptable limits.

Visual Inspection

The Visual Inspection identified some rust and the need for a replacement level gauge, possible weep from the temperature probe.

Cochrane Main Station TX1, SN: 288692

All oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.100%) is effective.
Furans DP is 884.
PCB is reported as 36 ppm.

Interpretation and Recommendation

We recommend retrofilling with Type II mineral oil (oxidation inhibitor 0.3%).

Visual Inspection

The Visual Inspection did not identify any areas of concern.

Cochrane Main Station TX1 TC, SN: 288692

Moisture (155 ppm), interfacial tension (18 dynes/cm) and acid number (0.313 mg KOH/g) are unacceptable.
All other oil quality properties and dissolved gas levels are within acceptable limits.
PCB is reported as 41.9 ppm.

Interpretation and Recommendation

We recommend conducting a Retrofill Treatment to restore oil quality properties to acceptable limits.

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Cochrane Main Station TX2, SN: 288693

Carbon monoxide (659 ppm) is slightly elevated.
All other oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.33%) is effective.
Furans DP is 953.
PCB is reported as 9.3 ppm.

Interpretation and Recommendation

Continue sampling on an annual basis.

Visual Inspection

The Visual Inspection did not identify any areas of concern.

Cochrane Main Station TX2 TC, SN: 288693

All oil quality properties and dissolved gas levels are within acceptable limits.
PCB is reported as <1 ppm.

Interpretation and Recommendation

Continue sampling on an annual basis.

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Cochrane Regulator, SN: 269579

Interfacial tension (29.7 dynes/cm) is questionable.
All other oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.17%) is effective.
Furans DP is 587.
PCB is reported as 5 ppm.

Interpretation and Recommendation

Continue sampling on an annual basis.

Furan results reflect a paper insulation condition better than actual as the recent oil replacement has removed some furan from the unit.

Visual Inspection

The Visual Inspection identified leaks from the level gauge and explosion vent. The main tank level gauge has oil in it and the tap changer level gauge has water.

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Cochrane Regulator TC, SN: 269579

Dielectric breakdown voltage (20 kV) is questionable.
All other quality properties and dissolved gas levels are within acceptable limits.
PCB is reported as 10.8 ppm.

Interpretation and Recommendation

Continue sampling on an annual basis.

Cochrane T1A, SN: 203109

Moisture (25 ppm), interfacial tension (24.8 dynes/cm), and power factor (0.110% at 25C) are questionable.
All other oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.02%) is depleted.
Furans DP is 751.
PCB is reported as 3.2 ppm.

Interpretation and Recommendation

Interfacial tension suggests that oil oxidation is advanced. Acidic oxidation by-products will ultimately accelerate the aging of the paper insulation and shorten the life of the unit.

We recommend conducting an Oil Reclamation Treatment to restore oil quality properties to acceptable limits.

Visual Inspection

The Visual Inspection identified a possible leak from the top lid and/or temperature gauge. The temperature gauge needs replacement.

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Cochrane T1B, SN: 203108

Interfacial tension (25.9 dynes/cm) is questionable.
All other oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.09%) is depleted.
Furans DP is 658.
PCB is reported as 5.6 ppm.

Interpretation and Recommendation

Interfacial tension suggests that oil oxidation is advanced. Acidic oxidation by-products will ultimately accelerate the aging of the paper insulation and shorten the life of the unit.

We recommend conducting an Oil Reclamation Treatment to restore oil quality properties to acceptable limits.

Visual Inspection

The Visual Inspection identified a leak from the top lid or bushing, and a slightly low oil level reading.

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Cochrane T1C, SN: 203107

All oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.10%) is effective.
Furans DP is 654.
PCB is reported as 4.3 ppm.

Interpretation and Recommendation

Continue sampling on an annual basis.

Visual Inspection

The Visual Inspection identified leaks at the main tank lid (or bushing) and conservator valve, and a low oil level reading.

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Cochrane T2A, SN: 286604

All oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.05%) is depleted.
Furans DP is 624.
PCB is reported as 21.6 ppm.

Interpretation and Recommendation

Continue sampling on an annual basis.

Consider retrofilling with inhibited oil and reduce PCB content.

Visual Inspection

The Visual Inspection did not identify any areas of concern.

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Cochrane T2B, SN: 272423

Moisture (22 ppm) is questionable.
All other oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.05%) is depleted.
Furans DP is 862.
PCB is reported as 6 ppm.

Interpretation and Recommendation

Continue sampling on an annual basis.

Consider retrofilling with inhibited oil and reduce PCB content.

Visual Inspection

The Visual Inspection did not identify any areas of concern.

Cochrane T2C, SN: 258423

Moisture (22 ppm) is questionable.
All other oil quality properties and dissolved gas levels are within acceptable limits.
Oxidation inhibitor (0.05%) is depleted.
Furans DP is 862.
PCB is reported as 6 ppm.

Interpretation and Recommendation

We recommend resampling to verify dielectric breakdown voltage.

Consider retrofilling with inhibited oil and reduce PCB content.

Visual Inspection

The Visual Inspection identified a leaking temperature gauge.

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Please find the attached Oil Data and Oil Data Charts provided for your ease in review of the testing results.

We trust this information will be of benefit to your transformer maintenance planning. If you have any questions or comments regarding this report, please do not hesitate to contact us.

My Regards,

Jody MacKenzie

Jody MacKenzie
Oil Diagnostics Technician

Attachment 2 (of 4):

OEB Appendix 2-AB

File Number:	EB-2024-0046
Exhibit:	2
Tab:	2
Schedule:	1
Page:	1
Date:	30-Aug-24
Capital Expnditures = In Service Additions	No

TO BE UPDATED AT THE DRAFT RATE ORDER STAGE

Appendix 2-AB

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

First year of Forecast Period:

2025

CATEGORY	Historical Period (previous plan[1] & actual)											
	2017			2018			2019			2020		
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var
	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access	15	2	-88.2%	15	13	-14.5%	-	2	--	-	31	--
System Renewal	330	263	-20.4%	395	242	-38.8%	270	224	-17.0%	519	145	-72.1%
System Service	290	427	47.1%	355	487	37.1%	345	371	7.6%	315	468	48.6%
General Plant	143	153	7.3%	33	140	330.8%	163	77	-52.7%	103	193	88.7%
TOTAL EXPENDITURE	778	845	8.6%	798	881	10.5%	778	674	-13.3%	936	837	-10.6%
Capital Contributions		8	--			--			--			--
NET CAPITAL EXPENDITURES		836	--		881	--		674	--		837	--
System O&M	$ 1,383	$ 1,230	-11.1%	$ 1,404	$ 1,379	-1.8%	$ 1,402	$ 1,416	1.0%	$ 1,392	$ 1,492	7.2%

CATEGORY	Historical Period (previous plan[1] & actual)												Forecast Period (planned)				
	2021			2022			2023			2024			2025	2026	2027	2028	2029
	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual	Var	Plan	Actual[2]	Var					
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000				
System Access	40	44	9.9%	-	6	--	-	35	--	-	-	--	15	15	15	15	15
System Renewal	488	142	-70.9%	500	104	-79.3%	360	60	-83.3%	90	90	0.0%	50	50	671	50	50
System Service	378	634	68.0%	400	464	16.0%	380	349	-8.0%	456	456	0.0%	6,785	4,233	5,007	3,861	1,090
General Plant	68	39	-42.5%	120	373	210.8%	302	282	-6.8%	624	1,327	112.7%	64	706	64	64	646
TOTAL EXPENDITURE	973	859	-11.7%	1,020	947	-7.2%	1,042	727	-30.3%	1,170	1,873	60.1%	6,914	5,004	5,757	3,990	1,801
Capital Contributions			--			--			--			--					
NET CAPITAL EXPENDITURES		859	--		947	--		727	--		1,873	--	6,914	5,004	5,757	3,990	1,801
System O&M	$ 1,416	$ 1,466	3.6%	$ 1,449	$ 1,622	11.9%	$ 1,566	$ 1,769	13.0%	$ 1,981	$ 1,981	0.0%	$ 2,578	$ 2,668	$ 2,748	$ 2,830	$ 2,915

Notes to the Table:

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

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

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

Explanatory Notes on Variances (complete only if applicable)

Notes on shifts in forecast vs. historical budgets by category

Notes on year over year Plan vs. Actual variances for Total Expenditures

Notes on Plan vs. Actual variance trends for individual expenditure categories

Attachment 3 (of 4):

OEB Appenidx 2-AA

File Number:	EB-2024-0046
Exhibit:	2
Tab:	2
Schedule:	1
Page:	1
Date:	30-Aug-24
Net Capital/Gross Capital	Gross Capital

Appendix 2-AA
Capital Projects Table

Projects	2017	2018	2019	2020	2021	2022	2023	2024 Bridge Year	2025 Test Year	2026	2027	2028	2029
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
System Access													
Metering	1,770	12,829	1,796	30,699	43,959	6,033	35,040		15,000	15,000	15,000	15,000	15,000
System Access Gross Expenditures	1,770	12,829	1,796	30,699	43,959	6,033	35,040	0	15,000	15,000	15,000	15,000	15,000
System Access Capital Contributions													
Sub-Total	1,770	12,829	1,796	30,699	43,959	6,033	35,040	0	15,000	15,000	15,000	15,000	15,000
System Renewal													
Pole Changes- Cochrane	132,414	46,527	58,095	9,464	10,728	15,990	4,200		20,000	20,000	20,000	20,000	20,000
Pole Changes- Kapuskasing	1,487	16,038	3,144				2,803		20,000	20,000	20,000	20,000	20,000
Pole Changes-Iroquois Falls	743	1,590	20,653	5,042	16,330	8,218	33,654		10,000	10,000	10,000	10,000	10,000
Cochrane 5Kv Upgrade	82,726	89,815	129,474	130,079	103,945	79,434	19,484				621,000		
Substations	45,313	87,882	12,661		10,641			90,000					
System Renewal Gross Expenditures	262,683	241,852	224,027	144,585	141,644	103,642	60,141	90,000	50,000	50,000	671,000	50,000	50,000
System Renewal Capital Contributions	8,321												
Sub-Total	254,362	241,852	224,027	144,585	141,644	103,642	60,141	90,000	50,000	50,000	671,000	50,000	50,000
System Service													
Kapuskasing - 5Kv to 25Kv Conv. Upgrad	222,190	365,034	267,467	326,228	336,098	265,347	6,550	285,720	627,247	1,000,000			
Iroquois Falls - 2.4 to 12 Kv Upgrade	204,484	121,507	93,164	68,968	5,273	17,090	53,993	170,000					
Cochrane Feeder Fortification												485,000	
Cochrane New Station			10,598	72,813	292,798	181,708	288,952		5,087,500	3,233,324	3,779,882	2,285,832	
Iroquois Falls - 2.4 to 12 Kv Upgrade - Downtown											1,227,062	1,090,077	1,090,077
Iroquois Falls - 2.4 to 12 Kv Upgrade - Millgate									1,070,677				
System Service Gross Expenditures	426,674	486,541	371,229	468,009	634,169	464,145	349,495	455,720	6,785,424	4,233,324	5,006,944	3,860,909	1,090,077
System Service Capital Contributions													
Sub-Total	426,674	486,541	371,229	468,009	634,169	464,145	349,495	455,720	6,785,424	4,233,324	5,006,944	3,860,909	1,090,077
General Plant													
Transportation Equipment		85,492	135,435	60,387		213,425	118,513	410,754		641,717			582,315
Computer Hardware			2,164			6,843	8,496	25,000	5,000	5,000	5,000	5,000	5,000
Computer Software	97,120	18,521		25,545		22,790	150,730	719,993	20,000	20,000	20,000	20,000	20,000
Buildings						21,623	4,270		30,000	30,000	30,000	30,000	30,000
Power Operated Tools								86,200					
Land								85,000					
Capital in Inventory (Spare Parts)	34,415	35,984	-60,708	107,505	39,037	80,429	-4,646						
General Plant Gross Expenditures	131,535	139,997	76,891	193,437	39,037	345,110	277,363	1,326,947	55,000	696,717	55,000	55,000	637,315
General Plant Capital Contributions													
Sub-Total	131,535	139,997	76,891	193,437	39,037	345,110	277,363	1,326,947	55,000	696,717	55,000	55,000	637,315
Miscellaneous	21,911					27,890	4,500		9,000	9,000	9,000	9,000	9,000
Total	**836,252**	**881,219**	**673,943**	**836,730**	**858,809**	**946,820**	**726,539**	**1,872,667**	**6,914,424**	**5,004,041**	**5,756,944**	**3,989,909**	**1,801,392**
Less Renewable Generation Facility Assets and Other Non-Rate-Regulated Utility Assets *(input as negative)*													
Total	**836,252**	**881,219**	**673,943**	**836,730**	**858,809**	**946,820**	**726,539**	**1,872,667**	**6,914,424**	**5,004,041**	**5,756,944**	**3,989,909**	**1,801,392**

Notes:

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

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

Attachment 4 (of 4):

Fleet Summary 2024

NOW Fleet - 2019/2020/2021/2022/2023/2024

Unit #	Year	Make	Model	Description	Plate No.	Serial No./V.I.N.	G/L#	Kms	Town		
RT510	1962	WEST	RH4	REEL TRAILER	V72702	362850	5255-1510	-	kap	510	
PT511	1982	TJWE	PT4	POLE TRAILER	T1772E	2042131	5255-1513	-	Cochrane	511	plate updated april 1/20
RT513	1991	HMDE	TY	REEL TRAILER	J94829	FILE-147907685	5255-1511	-	Ifalls	513	
516	2005	BANDIT	65XL	CHIPPER	-		5255-1516	391	Cochrane	516	
517	2006	DODGE	DAKOTA	PICKUP	4589RX	1D7HW22K26S683981	5255-1517	193,632	Cochrane	517	Removed from Fleet Dec,2017
519	2008	FORD	DRW	DUMP TRUCK	BY 37579	1FDAF57R68EA18999	5255-1519	53,526	Cochrane	519	
520	2007	INTL	40S	DIGGER DERRICK	4499VC	1HTMMAAN57H434919	5255-1520	32,897	Cochrane	520	
521	2008	FORD	COF	PICKUP	7253WJ	1FTRF14WX8KD43411	5255-1521	192,625	Ifalls	521	Removed from Fleet May,2019
522	2008	INTL	70S	BUCKET TRUCK	1358WJ	1HTWGAZR48J652951	5255-1522	58,809	Cochrane	522	
PT523	2008	BRIN	UNK	POLE TRAILER	H8310B	1L9MP40148G085368	5255-1523	-	Kap	523	
524	2010	CHEV	SILVERADO	PICKUP	1297YL	1GCPKPE0XAZ141472	5255-1524	204,219	Cochrane	524	Removed from Fleet March 2022
525	2010	DODGE	CARAVAN	VAN	BHSV845	2D4RN4DE0AR258115	5255-1525	167,545	CEO	525	removed from fleet sold to CTS marc 15,2020
526	2011	FRHT	FM2	BUCKET TRUCK	6869ZL	1FVHCYBS1BHAZ4392	5255-1526	49,842	Kap	526	
527	2011	CHEV	SILVERADO	PICKUP	9918ZF	1GCRKPE0XBZ272458	5255-1527	228,542	Super	527	Removed from fleet March 2022
PT528	2011	BROOKS BRO.	TB112 XL-10KHD	POLE TRAILER	J44320	1B9BS1125BM274032	5255-1528	-	Ifalls	528	
529	2011	KW	CON	DIGGER DERRICK	AA38652	2NKHHM7X4BM293010	5255-1529	31,010	Kap	529	
530	2012	FRHT	FM2	BUCKET TRUCK	AB55466	1FVHCYBS4CHBN5784	5255-1530	46,065	Ifalls	530	
RT531	2012	BROOKS BRO.	SLR	REEL TRAILER	K547OC	1B9US0820CM274207	5255-1531	-	Cochrane	531	
532	2013	CHEV	SILVERADO	4 X 4 PICKUP	AD17876	1GC1KVCG2DF170030	5255-1532	178,160	Kap	532	
RT533	2013	COMMERCIAL	SLRT	SELF LOADING TRAILER	13453C	1B9US0826DM274214	1-4-5255-3010			533	
534	2013	COMMERCIAL	SUPER 6000	SKYLIFT MINI-DERRICK	-	1839-MDS6000-LP	1-4-5255-3010		KAP	534	
535	2013	COMMERCIAL	TRAILER	TRAILER FOR MINI-DERRICK	L3454C	43YDC2724DC096793	1-4-5255-3010		Kap	535	
536	2013	WAJAX	C4047 PG	DIGGER TEREX	AF50482	1FVACYCYXEHFN7347	1-4-5255-3010	19,733	IFALLS	536	
537	2016	DODGE	RTR	4 X 4 PICKUP	AN30973	1C6RR7FG6GS285111	1-4-5255-3010	179,644	KAP	537	
538	2019	DODGE	SXT	4 X 4 PICKUP	AY80095	1C6RR7FG2KS591733	1-4-5255-3010	87641	Ifalls	538	
RT539	2019	BROOKS BRO.	SLRT7208	self loadng reel trailer	S8870Y	7K7US0823KM000603	1-4-5255-3010	#VALUE!	KAP	539	
540	2008	GMC	TC5500	BUCKET TRUCK	BC35594	1GDE5C3948F402742	1-4-5255-3010	56717	COCHRANE	540	
541	2022	CHEV	SILVERADO	PICKUP	BP 54520	3GCUYAED8NG219044	1-4-5255-3010	45934	KAP	541	
542	2022	CHEV	SILVERADO	PICKUP	BP 54521	3GCUYAED5NG206509	1-4-5255-3010	15162	COCHRANE	542	
BM543	2023	DR	AT45026BEN	BRUSH MOWER		3011145964	1-4-5255-3010		Ifalls	543	
544	2023	CHEV	SILVERADO	PICKUP	BX 53707	3GCUDAEDXPG334338	1-4-5255-3010	11728	COCHRAN	544	
545	2023	CHEV	SILVERADO	PICKUP	BX 53706	3GCUDAED3PG343608	1-4-5255-3010	6850	COCHRAN	545	
546	2024	CHEV	SILVERADO	PICKUP		1GCUDAED3RZ267603	1-4-5255-3010		Ifalls	546	
547	2024	CHEV	SILVERADO	PICKUP		1GCUDAED9RZ262437	1-4-5255-3010		COCHRAN	547	
548	2022		K-TRAIL	GALV DUMP TRAILER D610		2RYKBDD26NM030961	1-4-5255-3010			548	
549	2024	DITCH WITCH	C24X	TRENCHER WALK-BEHIND		DWPC24XACR0004103	1-4-5255-3010			549	
550	2023	DITCH WITCH	FX20	VACUUM EXCAVATOR W/150G		DWPFX20XHP0001125	1-4-5255-3010			550	
551	2022	DODGE	RAM 5500	BUCKET TRUCK	CA 41540	3C7WRNBL4NG383127	1-4-5255-3010	6602	Cochrane	551	

Fleet Evaluation Matrix for 2023

Factor	1 Point	2 Points	3 Points	4 Points	5 Points
Age	One point for each year of service based on "in service" date				
Mileage	One point for each 16,093 kilometers (10,000 miles) of use				
Type of Service	**Light duty** <u>Small Vehicles:</u> Engineering or Administration use <u>Large Vehicles:</u> on road use only and lightly loaded.	n/a	**Medium duty** <u>Small Vehicles</u>: trucks used by trades which are commonly loaded; <u>Large Vehicles</u>: mainly on road use and with average payload.	n/a	**Heavy duty** <u>Small & Large Vehicles:</u> trades use and commonly loaded for road and off road use
Reliability	Repair once every 3 months or less	n/a	Repair two or three times in 3-month period	n/a	Repair two or more times per month on average
Maintenance and Repair Costs	Accumulated cost as compared to original purchase cost is ≤ 20%	Accumulated costs as compared to original purchase cost is > 20% & ≤ 47%	Accumulated costs as compared to original purchase cost is > 47% & ≤ 74%	Accumulated costs as compared to original purchase cost is > 74% & ≤ 100%	Accumulated costs as compared to original purchase cost is ≥ 100%
Take into consideration body condition, rust, interior condition, anticipated repairs and accident history.					
Condition	**Excellent** Truck has no signs of deterioration and is close to like new condition	**Very Good** Truck is no longer in new condition but is still in very good shape	**Good** Truck has signs of regular use	**Fair** Truck is showing signs of early deterioration with advanced signs of rust and worn interior components.	**Poor** Truck has signs of rust perforation, seat covers are worn thru and repairs have been postponed due to age and cost benefit.

Heavy Duty Trucks	# 519	# 520	# 522	# 526	# 529	# 530	#536	#540	#551
Age	16	12	16	13	13	12	11	16	0
Mileage	3	2	4	3	2	3	1	3	0
Type of Service	5	5	5	5	5	5	5	5	5
Reliability	2	3	2	1	1	1	2	2	0
Maintenance and Repair Costs	2	2	2	1	1	1	2	3	0
Condition	2	3	3	2	2	1	3	3	2
Total Score	30	27	32	25	24	23	24	32	7

Light Duty Trucks	#532	#537	#538	#541	#542	#544	#545	#546	#547
Age	11	8	5	2	2	1	1	1	1
Mileage	11	11	5	3	1	1	1	1	1
Type of Service	3	3	2	1	1	1	1	1	1
Reliability	2	2	2	1	1	1	1	1	1
Maintenance and Repair Costs	2	2	2	1	1	1	1	1	1
Condition	4	4	4	1	1	0	0	0	0
Total Score	33	30	20	9	7	5	5	5	5

Other Equipment	RT# 510	PT# 511	RT# 513	# 516	PT# 523	PT# 528	RT# 531	RT#533	RT#534	DT#535	RT#539	BM#543	#548	#549	#550
Age	50	50	32	18	15	12	11	10	10	10	4				0
Mileage	0	0	0	0	0	0	0	0	0	0	0				0
Type of Service	5	5	3	3	5	5	5	5	5	5	5				1
Reliability	1	1	1	1	1	1	1	1	1	1	1				1
Maintenance and Repair Costs	3	0	0	0	0	0	0	0	0	0	0				0
Condition	4	4	4	2	3	2	1	2	2	2	1				1
Total Score	63	60	40	24	24	20	18	18	18	18	11				3

Fleet Replacement Schedule

Unit #	Year	In Service Date mm/dd/yy	Original Book Value	Description	Score	2012	2013	2014	2015	2016	2017	2018	2019	2020
Small Trucks (8 Year Cycle)														
514	2004	2004-03-15	$ 37,664.24	Dodge 1500 ST QD 4X4 LBX		removed from fleet								
517	2006	2006-05-23	$ 28,305.47	Dodge Dakota ST Club		removed from fleet								
521	2008	2008-05-23	$ 27,313.43	Ford F150 4X4 SS REG		removed from fleet								
524	2010	2010-05-07	$ 29,218.00	Chev Silverado		removed from fleet								
525	2010	2010-03-26	$ 27,683.00	Dodge Grand Caravan SE Wagon		removed from fleet								
527	2011	2011-02-16	$ 31,706.00	Chev Silverado 1500		removed from fleet								
532	2013			Chev Silverado 1500	33									
537	2016	2016-04-18	$ 34,370.00	Dodge Ram 1500	30									
538	2019			Dodge Ram 1500	20									
541	2022	2022-03-29	$ 57,925.76	Chev Silverado 1500	9									
542	2022	2022-03-29	$ 58,033.11	Chev Silverado 1500	7									
544	2023	2023-09-15	$ 67,291.56	Chev Silverado 1500	5									
545	2023	2023-09-19	$ 68,335.09	Chev Silverado 1500										
546	2024	2024-04-11	$ 67,329.39	Chev Silverado 1500										
547	2024	2024-04-11	$ 68,287.09	Chev Silverado 1500										
Large Trucks (15 Year Cycle)														
506	2000	xx/xx/xx	?	International Digger Derrick		removed from fleet								
519	2008	2010-02-22	$ 54,329.00	Ford F550 4X4 Dump Box	30									
520	2007	2007-09-04	$ 202,295.00	International Digger Derrick	27									
522	2008	2009-01-06	$ 220,800.00	International Bucket Truck w/ Altec	32									
526	2011	2011-04-06	$ 276,423.00	Freightliner M2-106 Bucket Truck	25									
529	2011	2011-11-15	$ 220,005.00	Kenworth T300 4X2 Digger Derrick	24									
530	2012	2012-03-26	$ 281,345.00	Freightliner Bucket Truck w/ Posi-Plus	23									
536	2013	2014-03-28	$ 261,375.00	Freightliner Digger Terex C4047 PG	24									
540	2008	2008-01-05	$ 150,239.15	GMC TC5500 Bucket Truck	32									
551	2022	2024-07-16	$ 284,039.00	Dodge Ram 5500 4x4 Altec	7									
Other Equipment (As Required based on Condition)														
510	1962	xx/xx/xx	?	Cable (Reel) Trailer	63									
511	1991	xx/xx/xx	?	Pole Trailer	60									
513	1982	xx/xx/xx	?	Cable (Reel) Trailer	40									
516	2005	2005-11-15	$ 15,114.60	Bandit Chipper Model 65XL	24									
523	2008	2009	$ 20,142.00	Pole Trailer	24									
528	2011	2011-05-17	$ 15,012.00	Brooks Bros. Pole Trailer PTB112XL-10KHD	20									
531	2012	2012-06-27	$ 20,767.00	Brooks Bros. Reel Trailer SLR	18									
533	2013			SLRT Self Loading Trailer	18									
534	2013			Skylift Mini-Derrick	18									
535	2013			Trailer for Mini-Derrick	18									
539	2019	2019-12-10	$33,316.00	Brooks Bros. Reel Trailer SLR	11									
543	2023	2023-08-03	$5,085.00	DR Power Brush Mower AT45026BEN										
548	2022	2024-04-03	$13,299.00	K-trail Galvanized Trailer										
549	2024	2024-04-24	$38,000.00	Ditch Witch Trencher Walk Behind C24X										
550	2023	2024-04-24	$48,200.00	Ditch Witch Vacuum Excavator FX20	0									
Total														

Scoring Results	
Point Ranges	**Action**
Under 18	Excellent - Continue to Monitor
18-22	Good - Continue to Monitor
23-27	Qualifies for Replacement
Over 27	Needs Immediate Consideration

2017 cost of Repairs

Cost Center 1	Cost Center 2	Cost Center 3	Current	Year to Date
U 506			0.00	0.00
U 510			0.00	4580.21
U 511			0.00	955.00
U 513			0.00	0.00
U 514			0.00	0.00
U 516			0.00	0.00
U 517			0.00	0.00
U 519			0.00	[illegible]
U 520			700.11	[illegible]
U 521			0.00	537.95
U 522			0.00	14441.38
U 523			0.00	535.02
U 524			200.24	[illegible]
U 525			300.00	300.00
U 526			0.00	2387.78
U 527			1768.54	8331.42
U 528			0.00	0.00
U 529			0.00	13227.72
U 530			0.00	5451.27
U 531			0.00	200.00
U 532			0.00	943.19
U 534			4507.16	6539.50
U 535			0.00	0.00
U 536			0.00	834.06
U 537			555.00	898.14
			8121.05	65578.62

CAPITALIZATION OVERVIEW

NOW Inc.'s capital assets are recorded and recognized at cost, and include direct labour and benefits, equipment and materials, fleet and contractor costs, which are incurred during the development, implementation, or construction of the asset. International Financial Reporting Standards (IFRS) prescribe which costs can be included as part of the cost of an asset and indicates that only costs that are directly attributable to a specific asset can be capitalized. Indirect overhead costs, such as general and administration costs that are not directly attributable to an asset are not capitalized by NOW Inc.

International Accounting Standards (IAS) require an entity to capitalize and depreciate separately each part of an item of Property Plant and Equipment (PP&E) that has a cost that is significant in relation to the total cost of the item. This requirement means that the total cost of a PP&E item should either be allocated to each significant part (where acquired as a whole) or (if constructed) the cost should be capitalized according to the significant part

Certain capital assets may be funded or paid by a customer or third-party developer through capital contributions. Capital contributions are recognized as deferred revenue and classified as a reduction to rate base.

Under IFRS, an entity must present and record separately from PP&E those assets that are within the scope of IAS 38. NOW Inc. has included intangible assets as PP&E for rate setting purposes.

Material Cost

These costs include stocked items taken from warehouse and issued out to each project as well as direct materials which are purchased and delivered to the job site directly. These costs represent the purchase price and initial delivery/handling costs of the materials.

These costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management, hence there is no impact on the amount of material costs being capitalized for IFRS.

Labour Costs

The labour costs that are capitalized to PP&E comprise of engineering, design, powerline technician, construction, and supervision time with working timesheets which record the nature of the actions and activities being undertaken and time spent on each task by each type of employee. These costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management.

Benefit Costs

Employee benefit costs represent the costs associated with employee pensions, vacations, sick leave, etc. For each hour of regular time recorded, via a timesheet, directly to a capital project, benefits are automatically allocated according to where the time is coded. These costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management.

Labour Burden

NOW Inc. does not allocate a general administration overhead charge "labour burden" to capital project costs.

Transportation and Fleet Costs

These costs include the costs associated with maintaining automobiles, trucks and equipment, trailers and other fleet equipment. Some of these costs include depreciation expense of the fleet vehicles, fuel costs, repairs, parts, insurance and all other items of expense necessary to keep the rolling stock in service. These costs can also include the labour costs and the associated benefits of the staff directly involved in rolling stock maintenance (mechanics and other garage staff) as tracked via timesheets or by contractors. Each vehicle has an individual work order and all the above costs related to the maintenance of that vehicle are accumulated under the work order, and therefore all the costs are directly attributable. A fleet rate is determined for each vehicle group by dividing the annual costs accumulated for each vehicle type by their annual usage. When a vehicle is used for a capital project, a fleet rate is charged based on the type of vehicle used multiplied by hourly usage of the vehicle.

Third Party Costs

Sub-contractor costs are incurred when NOW Inc. engages a third party to perform services. These costs are capitalized since they are directly attributable costs of bringing the asset to the location and to a condition necessary for it to operate in the manner intended by management.

Capitalization of Borrowing Costs

Borrowing costs that are directly attributable to the acquisition, construction, or production of a qualifying asset form part of the cost of that asset.

NOW Inc. includes borrowing costs on qualifying projects using the OEB prescribed rate for CWIP. NOW Inc. defines qualifying projects as those being greater than six months in duration. NOW Inc. applies interest on opening monthly balance of such capital work.

Customer Contributions

NOW Inc. is records customer contributions as deferred revenue and amortizes them as revenue over the life of the related asset. Capital contributions are included as an offset to rate base and the related amortized revenue as an offset to depreciation expense.

NOW Inc. confirms that there were no changes made to the capitalization policy since the last rebasing.

Attachment 1 (of 1):

Capitalization Policy

Policies and Procedures			
Department	Northern Ontario Wires Inc.	Issued	
Section	General	Effective:	Sept 18, 2008
Subject:	**CAPITALIZATION POLICY**	Page:	1 of 2
Approved by:		Revised:	

1. POLICY

1.1 Northern Ontario Wires Inc. shall implement a Capitalization policy as required.

2. PURPOSE

2.1 The purpose of capitalizing expenditures is to provide for an equitable allocation of cost among existing and future customers.

3. SCOPE

3.1 A capital expenditure is defined as any significant expenditure incurred to acquire, construct or develop land, buildings, plant, engineering structures, machinery and equipment expected to provide future economic benefits to the company and its customers. A capital expenditure must provide a benefit lasting beyond one year. Capital expenditures also include the improvement or "betterment" of existing assets. A "betterment" includes increasing the capacity of the asset, lowering associated operating costs, improving the quality of output or extending the asset's useful life. Capital assets include electric plant, transmission, generation and distribution facilities, meters, vehicles, office furniture, computer equipment and other equipment.

4. RESPONSIBILITY

5. DEFINITIONS

6. REFERENCES and RELATED STATEMENTS of POLICY and PROCEDURE

7. PROCEDURE

7.1 Expenditures for repairs and/or maintenance designed to maintain an asset in its original state are not capital expenditures and should be charged to an operating account.

7.2 Whether capital assets are purchased or constructed by the Corporation they are stated at cost and include contracted services, material, labour, engineering costs and overheads, including associated interest costs.

7.3 Betterments Versus Repairs

As noted previously a betterment is defined as the cost incurred to enhance the service potential of a capital asset. Service potential may be enhanced when

there is an increase in physical output or service capacity, associated operating costs are lowered, the useful life is extended, or the quality of output is improved.

7.4 A repair is defined as the cost incurred in the maintenance of the service potential of a capital asset.

8. ATTACHMENTS

Nil.

CAPITALIZATION OF OVERHEAD

Both IFRS and CGAAP treatment for PP&E is to recognized the asset initially at cost. The difference in the standards relate to the type of cost inputs that can be included in the acquisition amount.

Costs incurred for the following purposes are typically capitalized:

- purchase, construction and commissioning of specific assets providing future economic benefits;
- design and development of specific assets that will provide future economic benefits;
- additions to existing assets; and
- betterments that result in improvement of capacity, efficiency, or useful life

Expenditures that can be capitalized as PP&E or intangible assets under IFRS include direct labour, direct materials and supplies, transportation costs, directly attributable external costs, professional fees and permits. Indirect expenditures that can be capitalized include directly attributable borrowing costs, tools and transport and work equipment used in the capital project, indirect depreciation of dedicated equipment, and directly attributable indirect costs. There are some prohibitions that cannot be capitalized including general and administrative overhead and training costs.

Due to the potential differences resulting from a change in accounting policies from CGAAP to IFRS, NOW Inc. performed a review with the assistance of a third party IFRS consultant BDO along with discussions with the external auditors.

Labour Overhead Rates

NOW Inc. does not utilize fixed overhead rates for allocating burden to capital or operating projects. NOW Inc. converted its accounting system which enables the direct allocation of employee burden to specific accounts based on how the time is allocated on the time sheet. As such, actual costs are allocated without an overhead rate.

Indirect costs including other payroll obligations including vacations, statutory holidays, banked time and sick time are allocated according to the allocation of hours worked in a year. The cost driver to allocate indirect costs is hours worked which aligns with the directly attributable rate.

Fleet Expenses

The costs associating with running the fleet have been analyzed by the IFRS consultant and been audited at 2015 year end. Directly attributable expenses are allocated based on the actual vehicle hours charged to projects.

Other Overhead

The costs associated with other positions that support purchasing including finance and accounts payable have no portion allocated to capital. Although necessary to acquire assets in order to put in service, this cost is deemed indirect, and not attributed to capital.

Burden Rates

NOW Inc. burden rates are based on identifiable and discrete cost drivers that vary according to direct labour and material changing. This has not changed since the last rebasing.

Attachment 1 (of 1):

OEB Appendix 2-D

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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	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Historical Year	2023 Historical Year	2024 Bridge Year	2025 Test Year
Operations	$ 873,163	$ 1,055,371	$ 1,078,718	$ 973,022	$ 1,040,564	$ 1,072,725	$ 1,144,286	$ 1,117,020	$ 1,325,534
Maintenance	$ 495,810	$ 440,705	$ 488,484	$ 639,441	$ 536,320	$ 702,981	$ 743,962	$ 980,909	$ 1,370,467
Customer Service	$ 775,872	$ 749,498	$ 757,348	$ 688,585	$ 680,520	$ 642,584	$ 703,383	$ 776,167	$ 937,555
Administration	$ 686,563	$ 561,155	$ 603,262	$ 583,224	$ 603,046	$ 648,539	$ 766,468	$ 1,047,516	$ 1,035,613
Total OM&A Before Capitalization (B)	$ 2,831,408	$ 2,806,729	$ 2,927,812	$ 2,884,272	$ 2,860,450	$ 3,066,829	$ 3,358,099	$ 3,921,612	$ 4,669,169

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	2017 Historical Year	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Historical Year	2023 Historical Year	2024 Bridge Year	2025 Test Year	Directly Attributable? (Yes/No)	Explanation for Any Change in Treatment of Capitalized Overhead
employee benefits	$ 67,996	$ 54,621	$ 60,964	$ 37,587	$ 46,594	$ 93,836	$ 78,554	$ 77,361	$ 77,916	Yes	No material change in capitalization
costs of site preparation							.				
initial delivery and handling costs											
costs of testing whether the asset is functioning properly											
professional fees											
Materials and Fleet Costs	$ 71,159	$ 62,268	$ 90,297	$ 83,209	$ 63,935	$ 59,611	$ 40,672	$ 40,054	$ 40,342	Yes	No material change in capitalization
Total Capitalized OM&A (A)	$ 139,154	$ 116,890	$ 151,260	$ 120,796	$ 110,529	$ 153,447	$ 119,226	$ 117,415	$ 118,258		

% of Capitalized OM&A (=A/B)	5%	4%	5%	4%	4%	5%	4%	3%	3%		

COSTS OF ELIGIBLE INVESTMENTS FOR DISTRIBUTORS

NOW Inc. does not have eligible investments for connecting qualifying generation facilities.

NEW POLICY OPTIONS FOR THE FUNDING OF CAPITAL

1.0 Introduction

NOW Inc. is seeking Advanced Capital Module (ACM) approval for a new Municipal Transformer Station (MTS) in the Cochrane service territory. This is a needed, discrete and incremental capital project that is not funded through the distribution rates requested in this Cost of Service Application. This project, entitled "New Cochrane MTS", is expected to cost in the order of $15 million, be in-service by 2028 and is the largest capital project undertaken since the inception of NOW Inc..

This ACM request is prepared in accordance with direction provided by the OEB in the following documents ("the Reports"):

a. *Report of the Board – New Policy Options for the Funding of Capital Investments: The Advanced Capital Module*, dated September 18, 2014; and
b. *Report of the Board – New Policy Options for the Funding of Capital Investments: Supplemental Report*, dated January 22, 2016.

As stated in the Reports, the Advanced Capital Module ("ACM") "… advances the review and approval process for incremental capital from the year in which the proposed projects will be entering service (i.e. the IR term) to the preceding cost of service application in which a distributor is required to file a five year Distribution System Plan encompassing the cost of service test year and the four subsequent incentive rate setting ("IR") years".

This Exhibit sets out the OEB's ACM filing requirements and demonstrates how NOW Inc. has satisfied the eligibility criteria of materiality, need and prudence.

The Handbook to Utility Rate Applications dated October 13, 2016 states that: 1 "An ACM proposal is made during a cost of service application to identify, based on the 5-year capital plan in the Distribution System Plan, qualifying incremental capital expenditures during the subsequent years. The ACM allows for projects in the IRM period that are necessary but require funding beyond what is sustained by IRM-adjusted rates and customer and load growth. Reviewing ACM projects as part of a cost of service application allows for testing of the need, pacing and prioritization of projects as part of the more comprehensive review that occurs in processing a cost of service application".

The New Cochrane Municipal Transformer Station (MTS) is planned to be constructed at an estimated cost of $14,386.5 K over a four-year period as shown in the following Table 1.

Table 1

New Cochrane MTS – Capital Expenditure

	Year				
(K$)	2025	2026	2027	2028	Total
Capital Exp.	5,087.5	$3,233.3	$3,779.9	$2,285.8	$14,386.5

This capital expenditure includes design, equipment, construction and commissioning costs. In addition, this project will attract interest on a monthly basis at the OEB approved CWIP rate.

The new station is required due to the aging infrastructure of the existing station, its inability to handle the expected load growth, and significant safety and environmental concerns. The existing Cochrane MTS was built in the 1950s and has long been a critical component of the local power infrastructure. However, after more than six decades of service, the station's age has become a significant concern. The two 10 MVA, 115/25kV transformers (T3 and T4), now 49 years old, along with the six single-phase 115/2.4kV transformers that feed the 4.16kV feeders, which range in age from 64 to 71 years old, are all outdated and have either reached or exceeded their typical useful life. As a result, the existing infrastructure is no longer adequate to meet the current and future electricity demands of the area.

2.0 ACM Eligibility

In order to be eligible, an ACM claim must be incremental to a distributor's capital requirements as funded by existing rates; and satisfy the eligibility criteria of materiality, need and prudence, as set out in the ACM Reports. These criteria and demonstration of how the New Cochrane MTS meets such criteria are discussed below.

2.1 Materiality

The ACM addresses the question of materiality by applying the ACM "materiality threshold formula", which defines the level of capital expenditures that a distributor should be able to manage within current rates. This test provides that any incremental capital amounts approved for recovery must be within the total eligible incremental capital amount calculated and must clearly have a significant influence on the operation of the distributor.

The Board-defined materiality threshold is represented by the following formula:

$$\text{Threshold Value (\%)} = 1 + [(RB/d) \times (g + PCI \times (1 + g))]) \times ((1 + g) \times (1+ PCI)^{n- 1} + 10\%$$

Where:

RB = rate base from the distributor's proposed cost of service

d = depreciation from the distributor's proposed cost of service

g = growth calculated based on the percentage difference in distribution revenues between the most recent complete year and the distribution revenues from the most recent approved test year in a cost of service application

PCI = Price Cap Index (IPI-0.3 stretch factor)

n = number of years since the last rebasing

As per the September 18, 2014 OEB Report, "As part of the cost of service application, distributors must provide a preliminary estimate of the materiality threshold value (and consequently, the total eligible incremental capital amount) for the subject year in which the proposed project is planned to enter service in order to provide the Board with a degree of certainty that the distributor will meet the threshold criteria. As noted above, the quantum of the threshold and the maximum allowable capital amount for the applicable year will be confirmed at the time of the IR application." Accordingly, NOW Inc. is providing the following preliminary materiality calculations which demonstrate that the forecast cost of the New Cochrane MTS is within the funding allowed by the ACM model. The ACM Model requires a number of inputs to establish the Eligible Capital Expenditure amount, these inputs are identified in the following Tables 2, 3 and 4. The results of the threshold calculation are provided in Tables 5 and 6.

Table 2

Baseline Assumptions – New Cochrane MTS

Description	Assumptions
Rate Base - 2025	$11,298,138
Depreciation Expense - 2025	$558,374
Growth Factor - Annual	-0.02%
Inflation – 2025 Base	3.6%
Less: Stretch Factor	0.3%
Price Cap Index	3.3%
# Years Since Rebasing	3

Table 3

Forecast Capital Expenditures (excluding Cochrane MTS)

K$	2025	2026	2027	2028	2029	Total
Capital Exp.	$1,826.5	$1,770.7	$1,977.1	$1,704.2	$1,801.0	$9,079.5

Table 4

Forecast Capital Expenditures (including Cochrane MTS)

K$	2025	2026	2027	2028	2029	Total
Capital Exp.	$6,914	$5,004	$5,757	$3,990	$1,801	$23,466

NOW Inc. has applied the ACM materiality threshold criteria using two methodologies. The first, (in Table 5) shows that the capital expenditures associated with Cochrane MTS in each of the years 2025 - 2028 is less than the capital eligible for ACM funding. The second methodology (in Table 6) includes all Cochrane MTS capital expenditures in the 2025-2027 period in 2028 as this is the year in-service year that the project will be added to rate base. Live versions of the model "Capital Module Applicable to ACM and ICM" have been filed with this Application.

Table 5

Materiality Test Met – for Each Capital Expenditure Year

K$		2025	2026	2027	2028
Threshold Value (%)	*a.*	174%	176%	178%	181%
Depreciation Exp.	*b.*	$558.4	$558.4	$558.4	$558.4
Threshold Value ($)	*c.=a.xb.*	$972.7	$984.5	$996.6	$1,009.1
Capital Expenditure	*d.*	$6,914.0	$5,004.0	$5,757.0	$3,990.0
Eligible for ACM	*e.=d.-c.*	$5,941.3	$4,019.5	$4,760.4	$2,980.9
Cochrane MTS ACM Cap. Exp.	*f.*	$5,087.5	$3,233.3	$3,779.9	$2,285.8
Remaining ACM Funding Avail.	*g.=e.-f.*	$853.8	$786.2	$980.5	$695.1

Table 6

Materiality Test Met - for all Cap. Ex. In-Service in 2028

K$		2028
Threshold Value (%)	*a.*	181%
Depreciation Exp.	*b.*	$558.4
Threshold Value ($)	*c.=a.xb.*	$1,009.1
Capital Expenditure	*d.*	$16,090.0 *
Eligible for ACM	*e.=d.-c.*	$15,080.9
Cochrane MTS ACM Cap. Exp.	*f.*	$14,386.5*
Remaining ACM Funding Avail.	*g.=e.-f.*	$694.4
*Includes all Cochrane MTS Capital Expenditures for 2025-2028		

In each of methodologies above, the materiality eligibility criteria for an ACM is met as the Cochrane MTS ACM Capital Expenditure is less than the Eligible for ACM amount and is significant in relation to the overall capital budget.

The live Excel versions of the OEB Capital Module Applicable to ACM and ICM ("the Models") are filed with this Application. It is noted that the "the models" have been modified in order to allow for the inclusion of ACM capital expenditures in 2025.

2.2 Need

The New Cochrane MTS is identified in the Distribution System Plan which is included in this Application. The DSP includes a Material Narrative for the new station (E2/T2/S1/Att1/Appendix A, pg. 92 of .pdf) as well as supporting engineering reports that document the condition of the current station and the need for replacement. These reports, which can be found at E2/T2/S1/Att1/Appendix A-1 and Appendix A-2 are entitled as follows:

- *"Consequences of Inaction Regarding 115 kv to 25 to 25 kV and 115 kV to 4.16 kV Systems"*, dated June 28, 2023 prepared by 3iO Inc..
- "*Feasibility Study: New Transformer Station – Town of Cochrane Service Area*", dated July 17, 2023, prepared by McMillan Distribution Engineering Consulting

The reports identify risks associated with aged equipment within the existing Cochrane distribution station. The distribution station includes two (2) 10 MVA, 115/25 kV transformers (T3 and T4), which feed both East and West 25 kV distribution systems within the Town of Cochrane. There are also six (6) single phase 115/2.4 kV transformers which are used to feed both East and West 4.16 kV feeders within the Town of Cochrane. This station is critical to the supply and distribution of electricity to customers in the Town of Cochrane. Transformers T3 and T4 were installed in 1975. All 4.16 kV system transformers were installed prior to T3 and T4; their nameplates have fabrication dates ranging from 1953 to 1960. Many of the component assets within the existing Cochrane MTS are fully depreciated and are well beyond their life expectancy.

With respect to reliability, there is concern that the peak load of the entire Town of Cochrane will exceed the redundant capacity of the 115/25kV transformers, meaning that a failure on either of the 115 kV to 25 kV during a peak period will cause an overload on the remaining transformer. This will compromise the Cochrane distribution system.

With respect public safety and the environment, due to close proximity to the town's reservoir, a station failure could contaminate the local water supply. In addition, existing regulations do not allow for effective vegetation management due to the station's location being located close to the water supply.

With respect to employee health and safety, the 4.16kV building has exposed buswork mounted at low levels which is a significant concern and it does not meet modern equipment installation practices.

A recent picture of the Existing Cochrane MTS is provided in Figure 1 below:

Figure 1

Existing Cochrane MTS

The New Cochrane MTS will enhance system reliability by addressing the risk of transformer overloads at the existing station. With the anticipated increase in industrial load and the transition of 4.16kV loads to the 25kV system, the current transformers face potential overloads that could compromise power supply safety. The new station will improve load management and system resiliency, ensuring continuous and reliable power delivery even during peak loads or unexpected failures.

Should the funding for the New Cochrane MTS not be approved as requested, the needs identified above would not be addressed. Alternate plans would need to be developed that could include partial replacement of critical components, a phased in approach to replacement or not building the MTS at a new location. There are consequences to such alternatives that include not addressing health, safety, environment and reliability issues in a timely manner. Section 2.3 below and the Material Narrative (E2/T2/S1/Att1, Appendix A) for this project further describe and assess alternatives that have been identified.

2.3 Prudence

A distributor needs to establish that the incremental capital amount it proposes to incur is prudent. To satisfy the "prudence test", a distributor must demonstrate that its decision to incur the incremental capital represents the most cost-effective option for its customers (though, not necessarily the least initial cost option).

Alternatives Considered

NOW Inc. evaluated several alternatives to address the capacity constraints and reliability concerns of the Cochrane MTS.

The recommended option is to build a New Cochrane MTS at a new location with two 18 MVA transformers. This provides coverage of both current and anticipated future load demands, offers enhanced system flexibility and reliability, and reduces long-term maintenance and operational costs. The new station will be built on the west side of Cochrane, chosen for its proximity to the Hydro One 115kV transmission supply and the availability of vacant land owned by the Town of Cochrane. Additionally, this option ensures that the new station is located away from the water supply, mitigating the environmental risks associated with the existing station.

An alternate approach proposed building a new station with a scaled-down scope, utilizing one 18 MVA transformer and retaining the existing two 10 MVA transformers as backup. While this approach offered initial cost savings, it was dismissed due to the inherent reliability risks associated with relying on 50+ year old transformers.

Maintaining the status quo was also considered but was deemed unsuitable. Without any upgrades or new construction, the existing infrastructure would continue to face risks of overloads and failures, with no capacity to support future load growth. Additionally, rebuilding the existing Cochrane MTS was reviewed. While this approach would address immediate reliability concerns, it involves significant challenges, including high long-term costs, potential operational disruptions during the rebuild process, and ongoing environmental concerns due to the station's proximity to the water supply.

Other options explored included the addition of Distributed Energy Resources (DER) to address capacity, obtaining emergency backup capacity through Hydro One's distribution system, and relying on participation in province-wide Conservation and Demand Management (CDM) programs. However, each of these alternatives presented limitations in terms of reliability, cost-effectiveness, and the ability to address the underlying issues with the aging infrastructure.

Project Cost Estimates and Cost Control

The estimated cost of the New Cochrane MTS is based on information received from equipment suppliers, contractors and engineering consultants. A competitive bidding process will be established and the NOW Inc. Procurement Policy will be followed.
All project expenditures will be accounted for and tracked through the NOW Inc. work order reporting process. A monthly project status and financial report will be prepared. Project status will be reported to the NOW Inc. Board at each meeting. On an annual basis, project costs will be reviewed by external auditors as part of the annual financial audit process.

2.4 Return on Equity

The Reports also state that if a distributor's regulated return exceeds 300 basis points above the deemed return on equity embedded in the distributor's rates, the funding for any incremental capital project will not be allowed. In 2023, NOW Inc. earned a regulated Return on Equity of 4.44%% compared to the Deemed Return on Equity of 8.78%. NOW Inc.'s regulated return for the years 2017 to 2022 inclusive has also been within 300 basis points, as can be seen in the following Table 7.

Table 7

Historical Return on Equity

	OEB Appr.	**Actual**						
(%)	**2017**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
ROE	8.78%	6.24%	9.97%	10.92%	8.99%	10.48%	9.06%	4.44%

2.5 Rate Riders and Effective Date

The New Cochrane MTS project costs will be updated in the ICM model to reflect actual expenditures when NOW Inc. comes before the Board with its 2028 annual incentive rate-setting application (for rates effective May 1, 2028). At that time, incremental revenue requirement, rate riders and bill impacts will also be calculated. NOW Inc. will be requesting special rate treatment for the Residential customer component of the revenue requirement associated with New Cochrane MTS. It is requested that rather than creating a rate rider for Residential customers, upon project in-service, their portion of revenue requirement be embedded in base rates, thus enabling recovery through the Distribution Rate Protection (DRP) mechanism. At the subsequent Cost of Service proceeding, the rate riders for other customer classes would cease and their allocated revenue requirement will be embedded in base rates going forward.

On an annual basis, in its 2026 and 2027 IRM applications, NOW Inc. will file information with respect to the schedule of the ACM, and project costs as compared to budget.

NOW Inc. understands the OEB requirements that in the price cap year in which the New Cochrane MTS goes in-service (e.g. for 2028 rates), if costs are less than 30% above what was documented in the DSP, NOW Inc. will explain differences in cost from the DSP forecast. If costs are 30% or more above what was documented in the DSP, NOW Inc. will re-file a business case for a new ICM if seeking recovery of incremental costs. NOW Inc. will also explain any significant differences in actual project costs and the capital budget approved and provide the incremental revenue requirement calculation and propose ACM rate riders.

ADDITION OF ICM ASSETS TO RATE BASE

NOW Inc. does not have any prior approved ACM or ICM projects to be added to rate base. The ACM requested in this Application (E2/T2/S5) is planned to be added to rate base in 2028.

SERVICE QUALITY AND RELIABILITY PERFORMANCE

Reliability Performance

NOW Inc. tracks service reliability statistics SAIDI (System Average Interruption Duration Index) and SAIFI (System Average interruption Frequency Index) including and excluding loss of supply related incidents. NOW Inc. had developed its target indices based on an average of the previous 5 years (2019-2023)

Figure 1

NOW Inc. Reliability Indices by Year – Historical 2019-2023

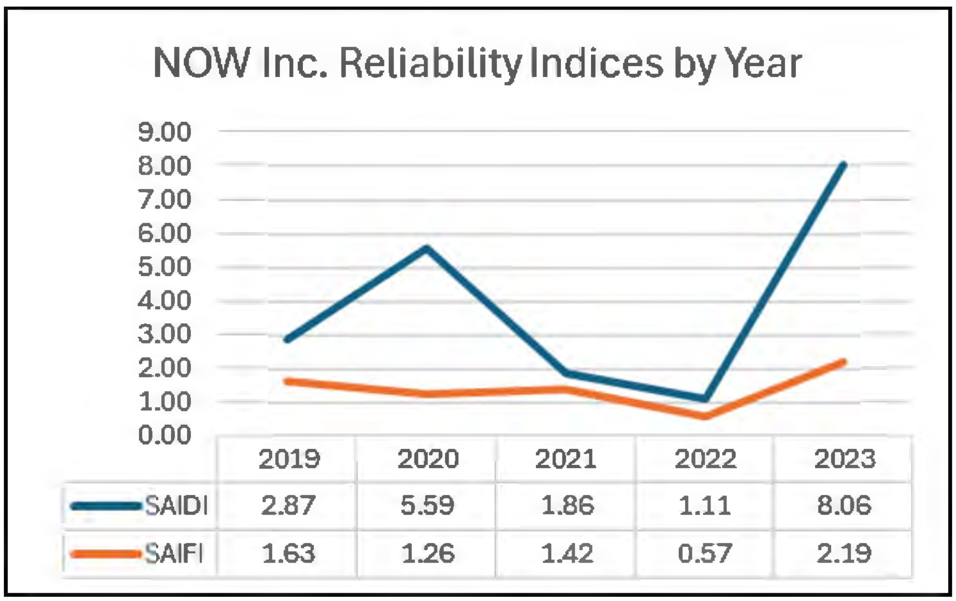


Figure 2

NOW Inc. Reliability Indices by Year Including Loss of Supply – Historical 2019-2023

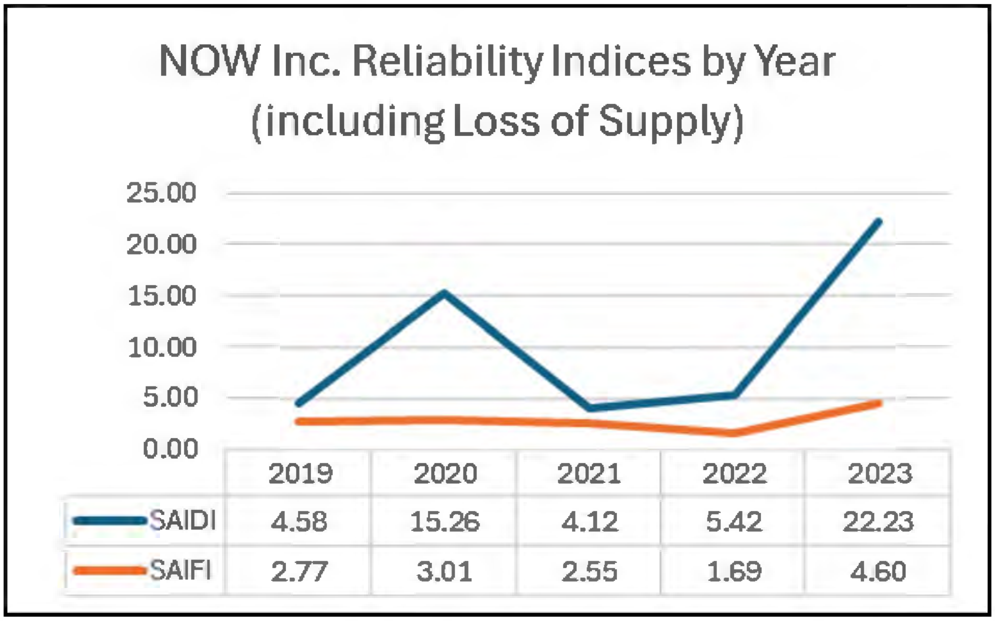
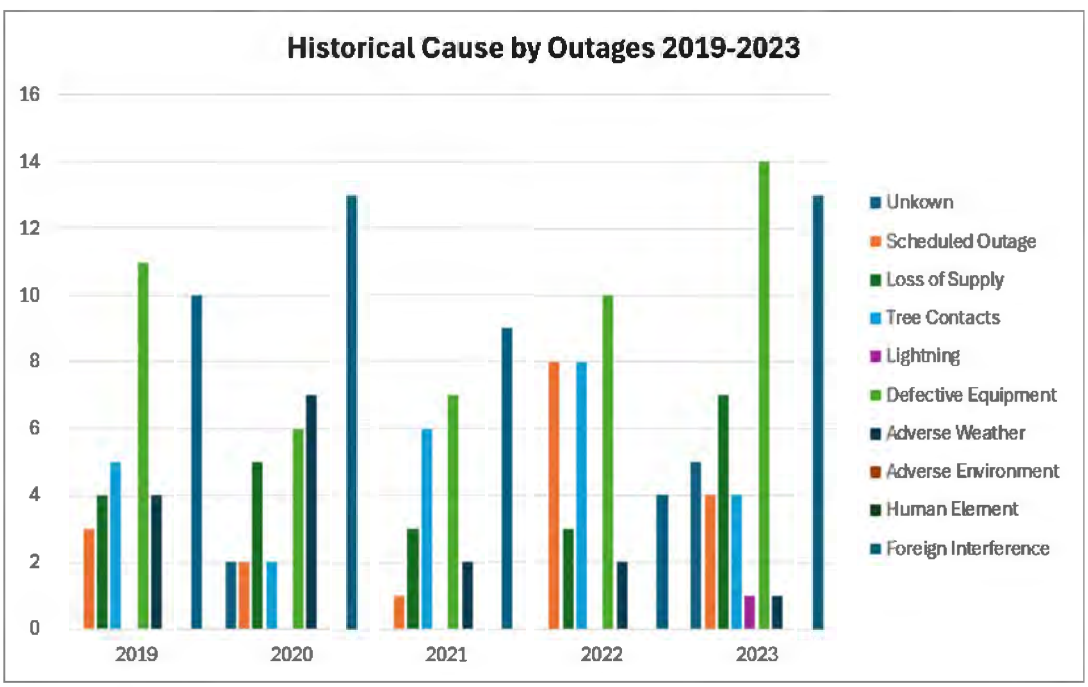


Figure 3

Historical Cause by Outages 2019-2023



NOW Inc. is committed to the reliability of the distribution system and has set 2025 target indices for SAIDI and SAIFI as follows:

Figure 4

Current and Proposed 2025 Reliability Targets

Excluding Loss of Supply	Proposed Targets
SAIDI	3.90
SAIFI	1.41
	Current Targets (2023)
SAIDI	3.69
SAIFI	1.47

In order to meet these targets NOW Inc. will need to continue to invest in capital and maintenance programs. In particular, the capital programs noted in Exhibit 2 with a primary driver of asset renewal are aimed at rebuilding infrastructure with a high probability of failure. Renewal of these assets helps to remove the risk to reliability and safety which would otherwise be unacceptable. Additionally, as noted in Exhibit 4, the increased investment in vegetation management will help improve these metrics.

2019

In 2019, the SAIDI and SAIFI scored 4.58 and 2.77, respectively. The leading contributor to this was loss of supply followed by defective equipment. While some other notable contributors included Tree Contacts and Scheduled Outages. These scored 4.35 of the SAIDI and 2.72 of the SAIFI totals.

2020

In 2020, the SAIDI total was 15.37, while the SAIFI was 3.01. The leading contributors were loss of supply, adverse weather and human element.

2021

The total SAIDI for 2021 was 4.12, while the SAIFI was 2.55. The leading five contributors were loss of supply, scheduled outages, tree contacts, defective equipment and foreign interference. These represented 4.03 of the SAIFI and 2.46 of the SAIFI totals.

2022

In 2022, the SAIDI totaled 5.42, while the SAIFI was 1.69. The leading contributors were loss of supply, scheduled outages, tree contacts, defective equipment and foreign interference. These contributed values of 5.4 and 1.66 of the SAIDI and SAIFI's totals, respectively.

2023

Total SAIDI of 22.23, and SAIFI of 4.60 in 2023 were significantly higher than the historic period. The major contributors to this are loss of supply, scheduled outages, tree contacts, defective equipment and foreign interference. Combined, these account for 21.68 of the SAIDI and 4.20 of the SAIFI. Tree contacts was a major contributor as can be seen in Exhibit 4 that includes the plan to address the vegetation issue. Scheduled outages also increase in order to allow for vegetation management on de-energized lines.

Figures 5-9 breakdown the selected cause code SAIDI and SAIFI scores within the 2019-2023 historical period. It shoes that Scheduled Outages were minimized until 2023 where they see a spike in scoring as a result of the increased need for maintenance that could not be achieved during loss of supply events. Tree Contacts and Foreign Interference fluctuated from year to year within this same timeline. Lastly, Defective Equipment started at a high, and has undergone an overall decrease throughout the years. The remainder of causes and their respective data can be found in the DSP, E2/T2/S1/A1.

Figure 5

Scheduled Outage SAIDI & SAIFI – 2019-2023

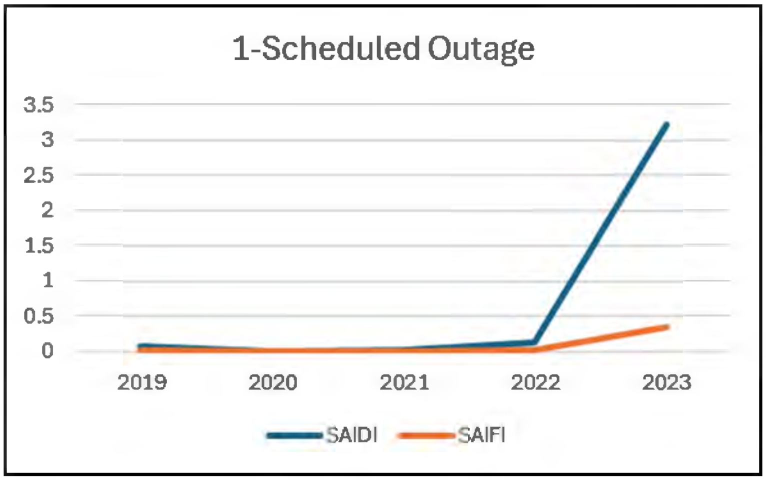


Figure 6

Loss of Supply SAIDI & SAIFI – 2019-2023

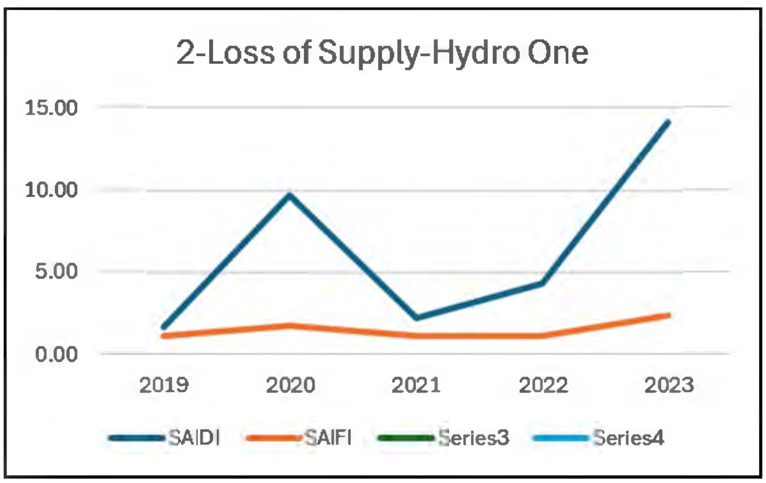


Figure 7

Tree Contacts SAIDI & SAIFI – 2019-2023

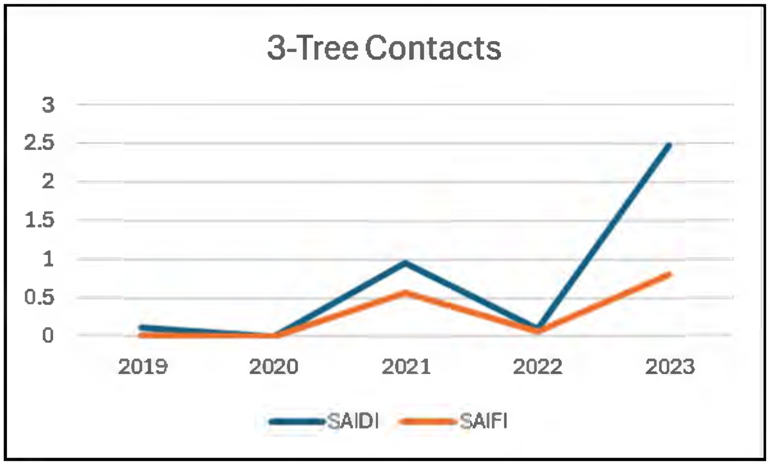


Figure 8

Defective Equipment SAIDI & SAIFI – 2019-2023

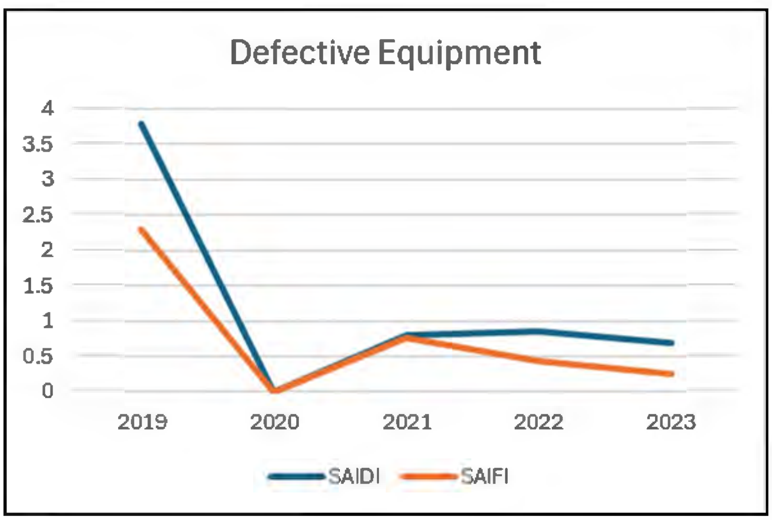
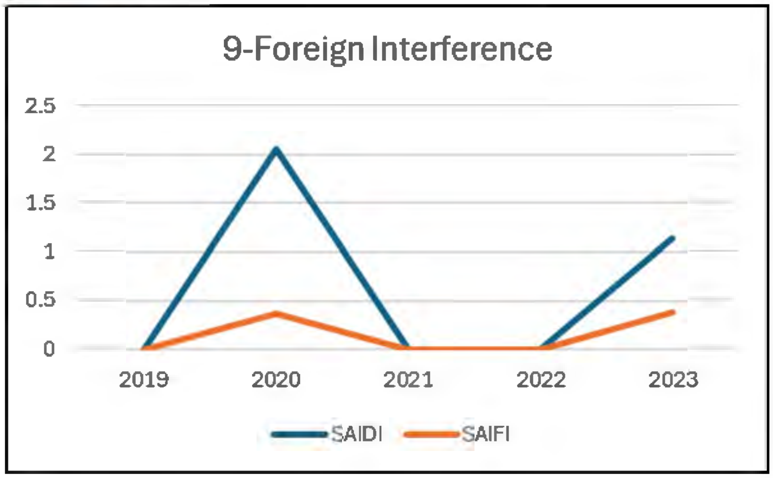


Figure 9

Foreign Interference SAIDI & SAIFI – 2019-2023



A summary of NOW Inc. Service Quality and Reliability Measures is provided in E2/T2/S7/Att1 (OEB Appendix 2-G). This information is consistent with the Scorecard.

Attachment 1 (of 1):

OEB Appendix 2-G

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Appendix 2-G
Service Reliability and Quality Indicators

Service Reliability

Index	Excluding Loss of Supply and Major Event Days					Including Major Event Days, Excluding Loss of Supply					Including Loss of Supply, Excluding Major Event Days					Including Loss of Supply and Major Event Days				
	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023	2019	2020	2021	2022	2023
SAIDI	2.87	5.59	1.86	1.11	8.06	2.88	5.59	1.86	1.12	8.06	4.58	15.26	4.12	5.42	22.23	4.59	15.28	4.12	5.43	22.23
SAIFI	1.63	1.26	1.42	0.57	2.19	1.64	1.26	1.42	0.57	2.19	2.77	3.01	2.55	1.69	4.60	2.78	3.01	2.55	1.69	4.60

5 Year Historical Average

SAIDI	3.896	3.899	10.322	10.330
SAIFI	1.413	1.415	2.924	2.927

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

Service Quality

Indicator	OEB Minimum Standard	2019	2020	2021	2022	2023
Low Voltage Connections	90.0%	100.00%				100%
High Voltage Connections	90.0%					
Telephone Accessibility	65.0%	100.00%	100.00%	100.00%	100.00%	100%
Appointments Met	90.0%	100.00%	100.00%	100.00%	100.00%	100%
Written Response to Enquires	80.0%	100.00%	100.00%	100.00%	100.00%	100%
Emergency Urban Response	80.0%	100.00%			100.00%	100%
Emergency Rural Response	80.0%					
Telephone Call Abandon Rate	10.0%					
Appointment Scheduling	90.0%	100.00%	100.00%	100.00%	100.00%	100%
Rescheduling a Missed Appointment	100.0%					
Reconnection Performance Standard	85.0%	100.00%	98.41%	88.04%	97.44%	100%