August 31, 2022

RESS

Ms. Nancy Marconi, Registrar
Ontario Energy Board
2300 Yonge Street, 27th Floor
Toronto, ON M4P 1E4

Dear Ms. Marconi,

Re: Electricity Distribution License ED-2002-0546
2023 Cost of Service Application (EB-2022-0059) for rates and other charges for Electricity Distribution to be effective May 1, 2023 (the Application)

PUC Distribution Inc. ("PUC") is pleased to submit its 2023 Cost of Service Application.

The Application and supporting materials are being filed through the OEB's web portal (RESS).

All correspondence related to this Application should be addressed to the undersigned.

Should you have any questions, please do not hesitate to contact us accordingly.

Respectfully submitted,

Tyler Kasubeck

Tyler Kasubeck
Regulatory Financial Analyst
Telephone: 705-759-3009
Email: regulatory@ssmpuc.com

2023 COST OF SERVICE RATE APLICATION

Combined Table of Contents

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

EXHIBIT 1

ADMINISTRATIVE DOCUMENTS

TABLES OF CONTENTS

EXHIBIT 2

RATE BASE

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

TABLE OF CONTENTS

EXHIBIT 3
OPERATING REVENUE

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

TABLE OF CONTENTS

EXHIBIT 4
OPERATING EXPENSES

TABLE OF CONTENTS

EXHIBIT 5

COST OF CAPITAL AND
CAPITAL STRUCTURE

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

TABLE OF CONTENTS

EXHIBIT 6

CALCULATION OF REVENUE DEFICIENCY OR SUFFICIENCY

TABLE OF CONTENTS

PUC DISTRIBUTION

EXHIBIT 7

COST ALLOCATION

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

TABLE OF CONTENTS

EXHIBIT 8

RATE DESIGN

TABLE OF CONTENTS

EXHIBIT 9

DEFERRAL AND VARIANCE ACCOUNTS

TABLE OF CONTENTS

EXHIBIT 1

ADMINISTRATIVE DOCUMENTS

TABLES OF CONTENTS

LIST OF TABLES

LIST OF FIGURES

APPLICATION

IN THE MATTER OF the Ontario Energy Board Act, 1998,
S.O. 1998, c.15, 3 Schedule B, as amended (the "OEB Act");

AND IN THE MATTER OF an Application by PUC Distribution Inc. under Section 78 of the OEB Act to the Ontario Energy Board for an Order or Orders approving or fixing just and reasonable rates and other service charges for the distribution of electricity as of May 1, 2023.

PUC DISTRIBUTION INC. (PUC)

APPLICATION FOR APPROVAL OF 2023 ELECTRICITY DISTRIBUTION RATES

EB-2022-0059

Filed: August 31, 2022

Tyler Kasubeck
Regulatory Financial Analyst
Telephone: 705-759-3009
Fax: 705-759-6553
Email: tyler.kasubeck@ssmpuc.com

EXHIBIT1: ADMINISTRATIVE DOCUMENTS

1.1 APPLICATION

The Applicant is PUC Distribution Inc. referred to in this Application as the "Applicant" or "PUC." The Applicant hereby applies to the Ontario Energy Board (the "OEB" or the "Board") pursuant to section 78 of the *Ontario Energy Board Act, 1998* (the "OEB Act") for approval of its proposed distribution rates and other charges, effective May 1, 2023 (the "Application").

The Applicant is an Ontario corporation with its office in the city of Sault Ste. Marie. The Applicant carries on the business of distributing electricity in its service territory which includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. PUC's 2023 Cost of Service Application (EB-2022-0059) (the "Application" or "COS" interchangeably) presents evidence demonstrating how PUC will develop, operate, and maintain its distribution system to ensure it provides safe, reliable, and cost-effective service to its customers.

The period for this COS covers five years with (i) historical information for the 2018-2021 period, (ii) 2022 Bridge Year; and (iii) a one-year forward test period – the 2023 Test Year. The Distribution System Plan ("DSP") provides an overview of PUC's asset planning process, objectives and goals, a review of PUC's asset-related operational performance over a 5-year historical period, and a forecast of planned capital expenditures over the 2023-2027 period. PUC's last Cost of Service application and DSP was filed April 2, 2018, for rates effective May 1, 2018.

This Application contains nine exhibits, including this Exhibit 1, as follows:

- Exhibit 1 - Administrative Documents

- Exhibit 2 - Rate Base, including the DSP
- Exhibit 3 - Operating Revenue
- Exhibit 4 - Operating Expenses
- Exhibit 5 - Cost of Capital and Capital Structure
- Exhibit 6 – Calculation of Revenue Deficiency or Sufficiency
- Exhibit 7 – Cost Allocation
- Exhibit 8 – Rate Design
- Exhibit 9 – Deferral and Variance Accounts

PUC has prepared this Application in accordance with the following:

- The Application has been prepared pursuant to the Report of the Board, Renewed Regulatory Framework for Electricity Distributors: A Performance Based Approach issued October 18, 2012 (the "RRFE");
- Unless specifically stated otherwise in the Application, the Applicant followed Chapter 1 and Chapter 2 of the OEB's Filing Requirements for Electricity Distribution Rate Applications last revised on April 18, 2022 (the "Filing Requirements") in preparing the Application;
- The Applicant has prepared a consolidated DSP in accordance with Chapter 5 of the OEB's Filing Requirements;
- PUC acknowledges that the OEB may publish an update to its cost of capital parameters for applications for 2023 distribution rates and that these matters will affect the Revenue Requirement that the Applicant has requested in this Application;
- The OEB's Handbook for Utility Rate Applications issued October 13, 2016; and
- PUC has not deviated from these filing requirements and provides a checklist of the filing requirements as Appendix A, which identifies the specific reference in the Application where relevant information is provided.

1.2 APPLICATION SUMMARY AND BUSINESS PLAN

Introduction

PUC provides a summary of the key elements of its Application in this section. These include the business, capital and operating plans that support the Application and the corresponding funding that is required to develop, manage, operate, and maintain its distribution system to provide safe, secure, reliable, efficient, and cost-effective service to its customers. PUC's plans are an outcome of its business planning efforts, enhanced asset management and capital expenditure planning processes, multi-faceted customer engagement, and coordinated planning with third parties. PUC developed its plans to address and appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives.

PUC's mission is to be a community leader providing safe and reliable utility services. Its vision is to improve communities through curiosity and innovation. Today, more than ever, PUC's focus is on being a sustainable company that is developing strategies to lower its carbon footprint, support communities, and offer excellent customer service.

About PUC

PUC is a municipality owned local distribution company ("LDC") serving the City of Sault Ste. Marie (the "City"), with a total licenced service area of 342 square kilometers and a customer base of approximately 33,865 customers. Of that service territory, 284 square kilometers are rural and 58 square kilometers are urban. The total population is 75,300.

PUC is a subsidiary of PUC Inc., one of two subsidiaries within the PUC group wholly owned by the City. The other subsidiary of the City is PUC Services Inc. PUC is a virtual utility and through its affiliate PUC Services Inc., it operates using a shared services model. This model provides significant efficiency benefits across all of the entities under the PUC umbrella. PUC Services Inc. shares certain resources with affiliates to create economies of scale and scope. For the purposes of this Application, the model has been validated and further updated through an independent third party.

PUC and PUC Services Inc. have won several awards since its last rebasing application in 2018 as follows:

2018 – Sault Ste. Marie Chamber of Commerce Safe Work, Sound Business Award
2018 – Urban and Regional Information Systems Association GIS Award
2019 – Sault Ste. Marie Chamber of Commerce Safe Work, Sound Business Award
2020 – Electrical Distributors Association (EDA) Customer Service Excellence Award
2020 – Electrical Safety Authority (ESA) Worker Safety Award
2022 – Algoma Public Health Community Champion Award
2022 – Sault Ste. Marie Chamber of Commerce Community Investment Award

PUC strives to exemplify excellence in every aspect of its business. From the work of its engineers and the professionalism of its customer service representatives to its resilient operations crews and all those in-between, PUC works together to deliver value at every level of the organization.

PUC's 5-Year Business Plan

In accordance with the OEB's Handbook for Utility Rate Applications, PUC has prepared a formal Business Plan that outlines PUC's overall strategy connecting its vision for the future.

Such a strategy is aligned with PUC's mission, vision and core values. PUC received approval of its 2023-2027 Business Plan from its Board of Directors on August 10, 2022.

This Business Plan identifies the key success factors that will enable PUC to be a best-in-class utility:

1. ***Completion of a DSP*** – This comprehensive engineering plan outlines PUC's asset management strategy and capital expenditure plans over a five-year horizon. PUC's plan provides clarity, direction and focus connecting PUC's vision for the future to its core strategies and strategic objectives. Customers, Employees, and Shareholder, the three pillars of the PUC Strategic Plan, are the focus and at the forefront of PUC's DSP.

   The fundamental objective of PUC's asset management program is to manage planning and engineering prudently and efficiently. This entails ensuring the design, inspection, maintenance, replacement, and retirement of all distribution assets are done in a sustainable manner that maximizes safety and customer reliability, while optimizing asset lifecycle costs.

2. ***People, Culture and Safety Strategy*** – Succession planning, employee growth and employee engagement will ensure that PUC has the right people in the right jobs over the coming years. Human resources and safety policies will position PUC as one of the top employers in Canada. Safety – one of PUC's core values – is always a top priority in PUC's plans and budgets. This includes both safety for the public and the safety of PUC employees.

   PUC is dedicated to creating a welcoming environment that encourages and promotes diversity, cross-culture working experiences and strong relationships within the community and with partners. PUC will strive to demonstrate leadership and foster a workplace culture where all employees feel empowered to bring their authentic selves to the workplace and do their best work.

3. ***Customer-Centric*** – This is another core value of PUC. With its COS, PUC reached out to customers through the biennial customer satisfaction survey as well as through specific COS surveys to gather feedback and confirmation on how PUC is doing. PUC is continually looking for ways to create positive experiences for customers, while at the same time encouraging behaviour that is more responsive to energy conservation. This has resulted in the launch of the MyPUC app, along with other consistent, proactive communication methods that are conducive to two-way interaction, real-time at the convenience of the customer.

4. ***Financial Success*** – PUC strives to produce consistent, allowable earnings, with returns that meet the expectation of PUC's shareholder. The focus is on growing value through investment and innovation. PUC continues to build on partnerships with other LDCs and organizations to strengthen the utility.

5. ***Innovation*** – This also is a core value of PUC. Building on its strong culture of innovation PUC has created throughout the organization, PUC will engage all staff to look for ways to improve efficiency and reduce costs through curiosity and innovation. This includes continuing to expand on initiatives such as 'becoming paperless' with creating electronic forms, promoting e-billing to customers, and also improving efficiencies in how we operate.

The Business Plan further outlines how the key challenges associated with PUC's service areas are mitigated and how the preferences of PUC's customers have been integrated into its 2023 COS and DSP. It does so in a manner that is consistent with the outcomes of the OEB's Renewed Regulatory Framework for Electricity Distributors ("RRFE"). The Business Plan summarizes PUC's target and forecasted performance with respect to performance metrics to ensure that PUC delivers on its strategic objectives. And finally, the Business Plan spans 2023-

2027 and presents the amount of revenue, capital and operating, maintenance and administrative expenses ("OM&A") required to justify PUC's proposed rates.

PUC continues to set risk management as a top priority. It has implemented an Enterprise-wide Risk Management program whereby the Senior Leadership Team become Risk Owners for one or more risks. They assume full accountability for successful management of their risk(s), including actions plans for risk mitigation and regularly reporting on progress. Over the COS horizon, the corporate risk register will continue to be reviewed to ensure that risks with a potential to affect the organization from a safety, reputation, financial and personnel perspective are identified and addressed. This will enable PUC to deliver on its commitments as presented with the 2023 COS.

PUC's business plan reflects its focus on being sustainable while balancing reliability and affordability for customers. Overall, the plan supports a successful COS, and management remains committed to being prudent in its expenditures and investments throughout the 5-year period while not sacrificing the excellent service customers have come to rely on.

PUC has included a copy of its Business Plan as Appendix B 2023 BUDGET AND 2024-2027 PROJECTIONS.

The key elements of the Application will now be discussed.

1.2.1 Revenue Requirement

The OEB approved $11,474,633 OM&A in PUC's 2018 rebasing application. This amount included property taxes in the amount of $298,477. In this Application, PUC breaks out the property taxes and incorporates it separately in the Revenue Requirement Work Form ("RRWF").

In Table 1-1 below, PUC is requesting a service revenue requirement for 2023 in the amount of $27,752,199. Based on the projected load forecast and customer growth for the 2023 Test Year, PUC has estimated a revenue deficiency of $4,998,586 based on its current rates.

Table 1-1: Revenue Requirement

Description	2018 OEB Approved	2023 Test Year	Change $	Change %
OM&A	$ 11,176,156	$ 13,533,701	$ 2,357,545	21.09%
Depreciation	$ 3,780,329	$ 5,425,413	$ 1,645,084	43.52%
Return on Equity	$ 3,587,690	$ 4,714,129	$ 1,126,440	31.40%
Deemed Interest	$ 2,390,627	$ 3,089,225	$ 698,597	29.22%
Property taxes and LEAP	$ 367,447	$ 415,590	$ 48,143	13.10%
PILs	$ 586,716	$ 574,141	$ (12,575)	-2.14%
Service Revenue Requirement	$ 21,888,965	$ 27,752,199	$ 5,863,234	26.79%
Revenue Offsets	$ (2,698,600)	$ (2,750,265)	$ (51,665)	1.91%
Base Revenue Requirement	**$ 19,190,365**	**$ 25,001,934**	**$ 5,811,569**	**30.28%**
Rate Base	**$ 99,658,054**	**$ 136,089,188**	**$ 36,431,134**	**36.56%**

The rates proposed to recover the projected revenue requirement and other relief sought are set out in Exhibit 8. The 2023 service revenue requirement represents an increase of $5,863,234 or 26.79% over the 2018 Board-approved amount of $21,888,965.[1]

This revenue deficiency of $4,998,586 doesn't includes PUC's ICM applications for Sub-station 16 ("Sub-16") (EB-2019-0170) and the ICM application for The Sault Smart Grid project ("SSG")

[1] Board Decision and Rate Order EB-2017-0071, dated September 27, 2018

(EB-2018-0219/2020-0249). The incremental revenue included in the 2023 Test year at existing rates, using the"PUC_2023_Load forecast – With Regression Analyssis_20220831", is $1,080,031. This changes the revenue deficiency to $3,918,555. If we remove these 2 ICM's from the $5,863,234 increase in revenue, from 2018 Board Approved to 2023 Test Year, this represents an increase of $4,783,203 or 21.8% over a 5-year period.

The main drivers of the 2023 revenue requirement changes from the 2018 Board-approved amount are:

- To provide a reasonable rate of return to the Shareholder, the City;
- Recovery of PUC costs to provide distribution services. Cost recovery is necessary to account for an increase in rate base and the associated depreciation from 2018-2022 capital additions, Sub-16 and SSG additions, resulting in an increased return from capital expenditures since the last COS application in 2018;
- Increased taxable income causing an increase in recovery of PILs payable;
- Funds necessary to service PUC's debt;
- To maintain current capital investment levels in infrastructure to ensure a safe, reliable distribution system;
- To continue with operating expenses necessary to maintain and operate the distribution system, meet customer service expectations and ensure regulatory compliance. These include:
    - Increased regulatory costs (i.e. cyber security, Ontario Rebate for Electricity Consumers Act (OREC), COVID-related items, etc.);
    - Increased bad debt expense;
    - Increased billing costs to facilitate RPP pricing options for customers; and
    - Increased regulatory rate filing costs.

- Increased operating costs as a direct result of the implementation of SSG which are more than offset by the energy savings on PUC customer bills;
- Higher inflationary increases for the 2023 as a result of growing inflation within the economy; and
- Maintaining adequate staffing requirements, including training and development in preparing for succession planning.

1.2.2 Load Forecast Summary

PUC's load forecast is weather normalized and considers factors such as historical power purchased load, weather, calendar related factors, number of customers and a trend variable. As outlined in Exhibit 3, PUC has used the same regression analysis methodology approved by the OEB in its 2018 Cost of Service ("2018 COS") application (EB-2017-0071). The regression analysis was conducted on historical electricity purchases to produce an equation that will predict weather normalized power purchases in 2023. The weather normalized purchased energy forecast is adjusted by a historical loss factor to produce a weather normalized billed energy forecast which is allocated to rate class using historical billing data by rate class. Upon completion of the regression analysis using 2020 and 2021 actual data PUC realized that a COVID-19 adjustment was needed to normalize the two General Service rate classes. Thus, PUC has normalized consumption for those rate classes which can be reviewed in full detail in Exhibit 3. Finally, PUC's Load Forecast has an adjustment for Conservation Demand Management ("CDM") to reflect the impact of activities that are expected to be implemented from 2023 to 2027 within its service territory based on its share of electricity use within the province, the IESO's 2021-2024 CDM Framework, and the IESO Planning Outlook. The full details of this adjustment can be reviewed in Exhibit 3.

Based on the load forecast methodology, the total billed 2023 Test Year kWh billed forecast is 578,772,961 which is a 7.97% decrease over PUC's 2018 OEB approved kWh billed forecast of 628,908,711. PUC exceeded the 2018 forecast in 2018 and 2019 but since then has seen a declining trend in overall consumption. Over the last 10 years PUC's consumption has also been showing a declining trend overall with an 11% reduction in consumption since 2012. As a result, the 2023 forecast has been developed to be more in line with the results from 2018 and 2021 along with an adjustment for CDM. The results are shown in Table 1-2 below.

Table 1-2: Comparison of Load Forecast 2018 OEB Approved & 2023 Test Year

Description	2018 Board Approved	2023 Test Year	Change
Billed kWh	**628,908,711**	**578,772,961**	**(50,135,750)**
% Difference			**-7.97%**
By Class			
Residential			
Customers	29,816	30,340	524
kWh	288,323,799	274,738,681	(13,585,118)
General Service <50 kW			
Customers	3,431	3,400	(31)
kWh	92,411,463	79,051,528	(13,359,935)
General Service 50 to 4,999 kW			
Customers	357	344	(13)
kWh	244,620,697	221,450,388	(23,170,309)
kW	614,743	547,687	(67,056)
Sentinel Lights			
Customers	354	317	(37)
kWh	209,800	193,841	(15,959)
kW	593	566	(27)
Street Lights			
Customers	8,070	8,037	(33)
kWh	2,398,221	2,459,994	61,773
kW	7,030	7,200	170
USL			
Customers	22	25	3
kWh	944,731	878,528	(66,203)
Total			
Customer/Connections	**42,050**	**42,463**	**413**
kWh	**628,908,711**	**578,772,961**	**(50,135,750)**
kW from applicable classes	**622,366**	**555,454**	**(66,912)**

The 2023 forecast of customers/connections by rate class was determined using a geometric mean analysis for all rates classes over the last 5- and 10-year periods. The customer counts in 2020 and 2021 were normalized as PUC noted a significant shift in customer count from the GS>50 rate class to the GS<50 rate class over this timeframe. Decreased consumption for customers in the GS>50 class caused the shift, primarily as a result of the ongoing COVID-19 pandemic. It remains to be seen how many of those customers will shift back to the GS>50 rate class. Over time PUC expects to see a gradual shift of customers back to the GS>50 rate class, as reflected in this Application. Table 1-3 Geometric Mean outlines the analysis completed and the geometric mean used for each rate class.

Table 1-3: Geometric Mean Used

	Residential	General Service <50 kW	General Service 50 to 4,999 kW	Sentinel Lights	Street Lights	USL
Used	1.0034	1.0008	0.9868	0.9805	1.0000	1.0236
Geomean (10 year)	1.0034	1.0008	0.9868	0.9805	0.9905	1.0236
Geomean (5 Year)	1.0034	0.9988	0.9956	0.9818	0.9811	1.0277

The expected number of customers/connections for the 2023 Test Year is 42,463 which is a 1% increase compared to the 2018 OEB Approved customers/connections of 42,050.
Further explanations of for the Load Forecast are included in Exhibit 3.

1.2.3 Rate Base and Distribution System Plan

Rate Base

The 2023 Rate Base calculated in Exhibit 2 of this Application is $136,089,188 and is comprised of the average of the balances at the beginning and the end of the 2023 Test Year, plus a working capital allowance, calculated as 7.5% of the sum of the cost of power and controllable expenses.

Table 1-4 below provides a comparison of the 2018 Board approved Rate Base of $99,658,054. The cumulative change in rate base was $36,431,134 which represents a 36.56% increase. This larger than normal increase is mainly the result of the two previously approved ICMs for Sub-16 and SSG.

Table 1-4: 2018 Board Approved Rate Base vs 2023 Test Year

Description	2018 board Approved	2023 Test Year	Change $	Change %
Average Gross Fixed Assets	$ 108,733,229	$ 166,892,585	$ 58,159,357	53.49%
Average Accumulated Depreciation	$ (15,770,354)	$ (36,460,700)	$ (20,690,346)	131.20%
Average Net Fixed Assets	**$ 92,962,875**	**$ 130,431,885**	**$ 37,469,011**	**40.31%**
Working Capital	$ 89,269,060	$ 73,322,849	$ (15,946,211)	-17.86%
Working Capital Allowance (%)	7.5%	7.5%	$ -	0.00%
Working Capital Allowance	**6,695,180**	**5,657,303**	**$ (1,037,877)**	**-15.50%**
Rate Base	**$ 99,658,054**	**$ 136,089,188**	**$ 36,431,134**	**36.56%**

Distribution System Plan

PUC's DSP, filed as Appendix C in Exhibit 2, was developed to address, and appropriately balance, the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives. PUC's investment plans are the outcome of its business planning efforts, enhanced asset management and capital expenditure planning processes, customer engagement, and co-ordinated planning with third parties.

All proposed capital projects are assessed within the framework of its capital budget priority and are outlined in the DSP. The capital budget forecast for 2023 is influenced by, among other factors, PUC's priority to maintain adequate security of supply to meet customer needs, as well as to replace end-of-life assets.

Major cost drivers for the DSP in 2023 are:

- System renewal and expansion;
- Deteriorating condition of distribution infrastructure and assets reaching end-of-life;

- Customer connections and regulatory requirements;
- System growth and planning criteria; and
- SSG.

Gross Capital Expenditures proposed for the 2023 Test Year are $10,705,871 (excluding capital contributions) per Table 1-5 below. This represents an increase of $5,317,695 or 98.69% over the 2018 DSP Capital Expenditures. 2023 Test Year expenditures includes $3,190,371 in carry over expenses from the SSG ICM Application.

Table 1-5: 2018 OEB Approved vs. 2023 Test Year Capital Expenditures

Planned Capital Expenditures	2018 OEB Approved	2023 Test	Change $	Change %
System Access	$ 1,540,849	2,339,499	$ 798,650	51.83%
System Renewal	$ 3,761,033	4,598,966	$ 837,933	22.28%
System Service	$ 86,294	3,190,371	$ 3,104,077	3597.09%
General Plant	$ -	577,035	$ 577,035	0.00%
Total Expenditures, Gross	**$ 5,388,176**	**$ 10,705,871**	**$ 5,317,695**	**98.69%**
Capital Contributions	$ (450,000)	$ (592,500)	$ (142,500)	31.67%
Total Expenditures, Net	**$ 4,938,176**	**$ 10,113,371**	**$ 5,175,195**	**104.80%**

Further explanations of for the changes are included in Exhibit 2.

1.2.4 Operations, Maintenance and Administration Expenses

PUC is proposing recovery through distribution rates of $13,533,701 in OM&A costs for the 2023 Test Year as detailed in Exhibit 4.

In 2018, PUC's actual OM&A expenditures were $11,250,796 compared to the approved amount in rates of $11,176,156 ($11,474,633 Board approved excluding property taxes).

These costs were necessary for PUC to safely operate and maintain the distribution system and to meet all incremental regulatory requirements.

As shown in Table 1-6 below, PUC is requesting 2023 test year OM&A expenses of $13,533,701 which is $2,357,545, or a 21.1% increase over the 2018 Approved amount.

Table 1-6: 2018 Board Approved Vs. 2023 Test Year OM&A

Test Year vs 2018 Board Approved	2018 Board Approved	2023 Test Year	Variance
Operations	$4,029,899	$4,434,334	$404,435
Maintenance	$2,106,659	$2,901,131	$794,472
Customer Service	$2,037,039	$2,043,800	$6,762
Administration	$3,002,559	$4,154,436	$1,151,876
Total OM&A	**$11,176,156**	**$13,533,701**	**$2,357,545**
Percentage change			**21.1%**

The graph in Table 1-7 below shows that OM&A expenses have approximated inflation less the productivity factor for 2019 through 2022. PUC recognizes that the Input Price Index ("IPI") has been on the rise, with an IPI of 3.30% for 2022. PUC expects the IPI to increase further in 2023 to above 7.7%[2] (CPI May 2021 to May 2022).

[2] Consumer Price Index, monthly, not seasonally adjusted (statcan.gc.ca) as of July 2022

Table 1-7: 2018 Board Approved Vs. 2023 Test Year OM&A Graph

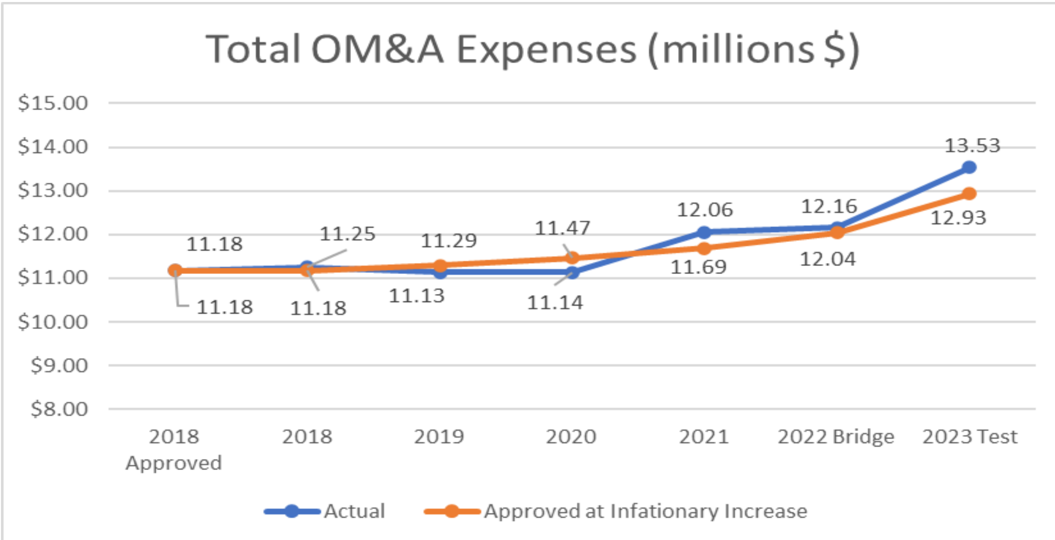


Table 1-8: 2023 Test Year Compared to Inflation

Description	2023 Test Year	2023 inflationary	Variance
OM&A	$ 13,533,701	$ 12,927,793	$ 605,908

Table 1-8 above shows the 2023 test year OM&A compared to inflationary impacts only results in a difference of $605,908. In addition to inflation, PUC is requesting the following items not currently recovered in rates:

- 2.5 FTEs as a result of the ongoing OM&A associated with SSG, estimated at $260,000 [ICM SSG EB-2018-0219/2020-0249];
- Updates to the PUC Services Shared Cost Allocation Model, filed as Appendix G in Exhibit 4, outlining an increase of $160,000; and

- Increased Cyber Security, Regulatory and IT resources (i.e. Green Button and APB Benchmarking) resulting in increased costs of $123,000.

Further explanations of the changes are included in Exhibit 4.

1.2.5 Cost of Capital

PUC has prepared its Application in accordance with the OEB Staff Report *Review of the Cost of Capital for Ontario's Regulated Utilities*, issued January 14, 2016. PUC has used the most recent cost of capital parameters issued by the OEB on October 28, 2021. There are no deviations from the Board's cost of capital methodology in this Application.

PUC has a promissory demand note with its parent, PUC Inc., bearing interest at 6.10%. For the purposes of this Application, PUC has used the current deemed long-term debt rate of 3.49% for this related-party debt. Also included is the remainder of financing to be finalized with Infrastructure Ontario ("IO") for the completion of SSG. PUC has been closely monitoring the financing rate environment with IO and has used a rate of 5.00% for this additional planned borrowing.

Taking into consideration the remainder of PUC's debt results in the following Weighted Average Cost of Capital in Table 1-9. Further details on all of PUC's debt's is provided in Exhibit 5.

Table 1-9: Weighted Average Cost of Capital

Description	Deemed Portion	Effective rate
Long-Term Debt	56.00%	3.97%
Short-Term Debt	4.00%	1.17%
Return on Equity	40.00%	8.66%
Weighted Debt Rate		**3.78%**
Regulated Rate of Return		**5.73%**

PUC acknowledges that the OEB will update the cost of capital parameters for 2023 Cost-Based rates before the OEB renders a decision on this 2023 application. Once the OEB has issued the new cost of capital parameters for 2023 cost-based rates, PUC will update its application accordingly.

Further explanations of for the changes are included in Exhibit 5.

1.2.6 Cost Allocation and Rate Design

PUC has not deviated from the Board's cost allocation and rate design methodology. PUC has consulted with the one customer of its Sentinel Light rate class and is agreeable to the rate increase of 13.13%.

Cost Allocation

The data used in the updated 2023 cost allocation study is consistent with PUC's cost data that supports the proposed 2023 revenue requirement outlined in this Application. The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to PUC from its engineering records, and its customer and financial information systems.

In 2018, PUC aligned its revenue-to-cost ratios for the Street Lights and Unmetered Scattered Load classes. The revenue from PUC's 2023 cost allocation does not require any adjustments as all rate classes fall within their proposed bands. Table 1-10 below shows the updated cost allocation percentages from this Application along with the OEB targets.

Table 1-10: Revenue-to-Cost Ratios

Rate Class	2023 Cost Allocation Study	2023 Proposed Ratios	Board Targets Min to Max	
Residential	99.95%	99.95%	85.00%	115.00%
General Service < 50 kW	117.87%	117.87%	80.00%	120.00%
General Service ≥ 50 to 4999 kW	91.16%	91.16%	80.00%	120.00%
Streetlights	90.84%	90.84%	80.00%	120.00%
Sentinel Lights	99.81%	99.81%	80.00%	120.00%
Unmetered Scattered Load	109.87%	109.87%	80.00%	120.00%

Rate Design

PUC is proposing to increase the fixed monthly charge for Residential class by 25%. PUC proposes to maintain the fixed/variable proportions assumed in the current rates to design the proposed monthly service charges. PUC has fully transitioned its Residential Rate Class to fixed rates.

Table 1-11 below provides a comparison of PUC's current 2022 distribution rates and the proposed 2023 distribution rates.

Table 1-11: Distribution Charges

Customer Class	Monthly Fixed Charge			Unit of Measure	Distribution Volumetric Charge		
	2022 Current	2023 Proposed	% Difference		2022 Current	2023 Proposed	% Difference
Residential	33.72	42.15	25.00%	$/kWh	N/A	N/A	-
GS < 50 kW	22.32	27.90	25.00%	$/kWh	0.0268	0.0334	24.63%
GS >50 to 4,999 kW	123.27	154.07	24.99%	$/kW	7.2479	9.0363	24.67%
Unmetered and Scattered	13.67	17.09	25.02%	$/kW	0.0412	0.0516	25.24%
Sentinel Lighting	3.83	4.78	24.80%	$/kW	35.7037	44.6252	24.99%
Street Lighting	1.47	1.84	25.17%	$/kWh	9.6161	12.0191	24.99%

Further explanations of for the changes are included in Exhibit 8.

1.2.7 Deferral and Variance Accounts

PUC typically disposes of its Group 1 Deferral and Variance Accounts ("DVAs") on an annual basis with its Incentive Rate Mechanism ("IRM") applications. Group 1 DVAs track the difference between revenues collected from customers and costs paid by PUC for the cost of power. Group 2 DVAs are typically associated with policy changes and track costs and revenues incremental to that which was approved in rates. PUC has been accumulating balances in its Group 2 accounts since the 2018 COS application. In addition, PUC has been tracking costs and carrying costs associated with the Sub-16 ICM and the SSG ICM. With approval of these amounts in this Application, they will be brought into rates and removed from Account 1508.

As outlined in Exhibit 9, PUC is requesting approval for the disposition of Group 1, Group 2 and Other Accounts in the amount of $143,472 as identified in Table 1-12 below. The amount allocated to Regulated Price Plan ("RPP") and non-RPP customers is also identified.

Table 1-12: Deferral and Variance Accounts

Accounts Requested for Dipposal	Account Number	Claim	RPP	Non RPP
Group 1 Accounts:				
Smart Metering Entity Charge Variance Account	1551	($17,032)	($16,289)	($743)
RSVA - Wholesale Market Service Charge	1580	$905,532	$595,207	$310,325
RSVA - Wholesale Market Service Charge - CBR	1580	($75,701)	($53,236)	($22,465)
RSVA - Retail Transmission Network Charge	1584	$448,439	$294,759	$153,680
RSVA - Power (excluding Global Adjustment)	1588	($902,204)	($593,019)	($309,184)
RSVA - Global Adjustment	1589	($347,605)	$0	($347,605)
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	$28,031	$18,425	$9,606
Subtotal - Group 1 Accounts		**$39,461**	**$245,847**	**($206,387)**
Group 2 Accounts:				
Other Regulatory Assets - Sub-Account - Pole Attachment Variance	1508	($27,302)	($17,946)	($9,356)
COVID-19 Rate Implementation Delay Variance Account (net)	1509	$14,747	$9,693	$5,054
COVID-19 Incremental Expense Variance Account	1509	$401,767	$264,082	$137,685
Retail Cost Variance Account - Retail	1518	($18,683)	($12,280)	($6,403)
Retail Cost Variance Account - STR	1548	$65,199	$42,856	$22,344
PILs & Taxes Variance	1592	($613,546)	($403,284)	($210,262)
Subtotal - Group 2 Accounts		**($177,818)**	**($116,880)**	**($60,938)**
Other Accounts:				
LRAM Variance Account	1568	$196,576	$129,592	$66,984
Subtotal - Other Accounts		**$196,576**	**$129,592**	**$66,984**
Total		**$58,219**	**$258,559**	**($200,341)**

The rationale for these proposals and further details on PUC's DVAs are provided in Exhibit 9. PUC is proposing a disposition period of one year for its DVAs and is requesting to establish new, continue and discontinue DVAs as proposed in Table 1-13 below.

Table 1-13: DVAs Commence/Continue/Discontinue

Group 2 and Other Accounts	Account Number	Commence Continue Discontinue	Explanation
Other Regulatory Assets - Sub Account - Incremental VVO Savings or Costs	1508	Commence	To record on-going SSG VVO impacts.
Other Regulatory Assets - Sub Account - EPC Contract Liquidated Damages	1508	Commence	To record liquidated damages due to performance or delay in EPC contract.
Other Regulatory Assets - Sub-Account - Pole Attachment	1508	Continue	On-going in event of a decrease in expected Pole Rental charge.
PILs and Tax Variance	1592	Continue	Remain available to use for other legislative tax changes not reflected in rates.
LRAM Variance Account	1568	Continue	On-going in event of future CDM programs.
Other Regulatory Assets - Sub-Account - ICM Sub-station 16	1508	Discontinue	Rate Rider in effect until April 30, 2023
Other Regulatory Assets - Sub-Account - Sault Smart Grid	1508	Discontinue	Rate Rider in effect until April 30, 2023
COVID-19 Deferral Account	1509	Discontinue	Final disposition at rebasing; no activity expected
Retail Cost Variance Account - Retail	1518	Discontinue	Final disposition at rebasing; forecast activity to April 30, 2023
Retail Cost Variance Account - STR	1548	Discontinue	Final disposition at rebasing; forecast activity to April 30, 2023

Further explanations for the changes are included in Exhibit 9.

1.2.8 Bill Impacts

PUC provides a summary of the bill impacts for typical customers in all customer classes in Table 1-14 below. The proposed electricity distribution rates are reasonable and do not require rate mitigation. The total bill impacts for a PUC residential RPP customer at the 10th consumption percentile is 6.16%. This impact is within the standard acceptable impact of 10.00%.

Table 1-14: Customer Bill Impacts

Bill Impacts			Total Bill Impacts		Distribution only Imacts	
Class	Consumption (kWh)	Consumption (kW)	Total Bill Increase/Decrease	Total Bill Impact %	Total Distribution Bill Increase/ Decrease	Total Distribution Bill Impact %
Residential	750	0	$3.16	2.59%	$5.67	15.79%
GS<50	2,000	0	($1.40)	(0.5%)	$5.09	6.13%
GS>50	57,220	145	($265.91)	(2.8%)	$190.24	15.28%
USL	3,600	0	$9.17	1.58%	$26.29	15.27%
Sentinel Light	50	1.00	$6.34	13.13%	$6.61	15.77%
Street Light	199,852	585	$2,184.67	5.28%	$3,912.43	21.15%

As mentioned in the rate design section above, the only customer that is greater than 10.00% bill impact is the Sentinel Light Class. PUC has consulted with its one customer of the Sentinel Light Class and determined that no further mitigation is required. All other bill Impacts remain at acceptable levels.

Incorporated in the overall monthly bill impact is the effect of the following major components of the electricity bill:

- Distribution rates (monthly service charge and volumetric rates);
- Disposition of deferral and variance accounts:
- Revised Retail Transmission rates;
- Regulatory charges;
- Loss factors;
- Revised Embedded Generation Rate Rider Refund; and
- Rate Rider Refund for Loss Carry forwards.

1.2.9 Additional Application Items

- PUC prepares budget information for the three major components of the budgeting process: revenue forecasts, operating and maintenance expense items, and capital requirements. This budget information was compiled for both the 2022 bridge year and the 2023 test year.

- The budget for the 2023 test year was prepared and approved by management in April 2022.
- The Business Plan is forward looking from 2023 and was approved by the PUC Board of Directors on August 10, 2022.
- Labour costs reflect the annual wage rate adjustments that were negotiated under collective agreements with its unionized employees.
- For non-unionized employees, the labour cost forecast is largely driven by increases that reflect market competitive compensation.
- PUC recognizes that the Input Price Index ("IPI") has been rising as of late with the 2022 IPI of 3.30%. PUC expects the IPI to increase further in 2023 to above 7.7% (CPI May 2021 to May 2022).
- The Applicant submits the proposed distribution rates contained in this Application are just and reasonable on the following grounds:
    - the proposed rates for the distribution of electricity have been prepared in accordance with the Filing Requirements;
    - the proposed adjusted rates are necessary to meet the Applicant's market-based rate of return and PILs (Payments in Lieu of Taxes) requirements;
    - unless otherwise noted in this Application, there are no impacts to any of the customer classes or consumption level subgroups that are so significant as to warrant the deferral of any adjustments being requested by the Applicant;
    - the other service charges proposed by the Applicant are the same as those previously approved by the Board; and

- such other and further grounds and material as counsel may advise and this tribunal may permit.

1.3 ADMINISTRATION

1.3.1 Executive Certification

Please see Appendix C for a signed certification.

1.3.2 Primary Contact Information

The Applicant:

PUC Distribution Inc.
500 Second Line East, P.O. Box 9000
Sault Ste. Marie, Ontario
P6A 6P2

Primary Application Contact:

Tyler Kasubeck,
Regulatory Financial Analyst
Telephone: 705-759-3009
Fax: 705-759-6553
Email: tyler.kasubeck@ssmpuc.com

1.3.3 Legal Representation

Borden Ladner Gervais LLP
Bay Adelaide Centre, East Tower
22 Adelaide Street West
Toronto, ON M5H 4E3

Primary Contact:

John A.D. Vellone
Partner
Telephone: 416-367-6730
Fax: 416-367-6749
Email: jvellone@blg.com

1.3.4 Internet Address and Social Media Accounts

The Application and related materials will be posted on PUC's website and will be available for viewing at the following internet address:

Ontario Energy Board Rate Application - Sault Ste. Marie PUC (ssmpuc.com)

PUC also has the following social media accounts to communicate with customers. These accounts can be found at the following internet addresses:

http://www.facebook.com/SSMPUC

https://twitter.com/ssmpuc

https://www.linkedin.com/company/puc-services-inc

1.3.5 Impacted Customers

Residents, businesses and institutions in the City of Sault Ste. Marie (with exception of all or part of six municipal addresses as listed on its distribution license), Township of Prince, Rankin Reserve, Township of Dennis (concessions 3, 4 and 5) who receive electricity distribution services from PUC will be affected by the Application. This includes customers within the following rate classes:

- Residential

- General Service Less Than 50 kW
- General Service 50 to 4999 kW
- Unmetered Scattered Load
- Sentinel Lighting
- Street Lighting

1.3.6 Statement of Publication of Notice of Hearing

PUC will follow the Board's instructions regarding the publication of Notice in relation to this Application. We recommend that the Application and related materials be published on PUC's website. If the OEB decides that publication in a paper format is necessary, then we recommend the Sault This Week. The Sault This Week is a weekly newspaper with circulation to 33,425 homes and covers PUC's entire service territory.

1.3.6 Bill Impacts for Notice of Application

The bill impacts resulting from this Application are within the Board's requirements, as shown in Table 1-15 below.

Table 1-15: Bill Impacts

Customer Class	Typical Usage per Month (kWh)	Distribution Bill Impact ($ per month)
Residential	750	$ 5.67
General Service less than 50 kW	2,000	$ 5.09

1.3.7 Form of Hearing Requested

PUC requests that this Application be completed through a written hearing to allow for greater cost-effectiveness and allow for added due diligence.

1.3.8 Requested Effective Date

PUC requests that the OEB make its Rate Order effective May 1, 2023.

In the event that the Board is unable to provide a Decision and Order in this Application for implementation by the Applicant as of May 1, 2023, the Application requests that the Board declare its current rates interim, effective May 1, 2023, pending the implementation of the Board's Rate Order for the 2023 rate year.

In the event that the effective date does not coincide with the Board's decided implementation date for 2023 distribution rates and charges, PUC requests permission to recover the incremental revenue from the effective date to the implementation date.

1.3.9 Statement of Deviations

PUC has not deviated from the Filing Requirements in preparing its Application, except where expressly mentioned. PUC has worked with OEB Staff to make updates to certain areas of the models for 2023 Cost of Service filers. These were the most up-to-date models available as models for 2023 filers. PUC made changes to some of the models to accommodate a 2023 Test Year.

1.3.9 Change in Methodology Used

The methodologies used in this Application are generally consistent with those applied in PUC's 2018 COS. PUC has made changes as required by the Filing Requirements which have evolved since the 2018 Application.

PUC has made some changes to its methodology for load forecasting in order to address the cessation of the Conservation First Framework for Conservation and Demand Management ("CDM"), as well as adjustments to address unusual customer patterns resulting from the COVID-19 pandemic. Please refer to Exhibit 3 for additional discussion of these items.

Consistent with the Filing Requirements, PUC has updated its load profiles form the version used in prior Cost of Service Applications. Please refer to Exhibit 7 for a discussion of the process and assumptions used.

1.3.10 Identification of Board Directives from Previous Board Decisions

Since PUC's 2018 COS application, the following board directives and applicable file numbers with reference to the completion of each action item is listed in Table 1-16 below.

Table 1-16: List of Prior Commitments

	Action Item	File # and Reference	Completion
1	"PUC's cost structure remains higher than its rate structure […] This settlement, <u>when combined with a continued focus on cost control and productivity by PUC</u>, will facilitate the alignment of rates and costs	EB-2017-0071 Schedule A pg. 8	As per table 1-7, PUC's costs have aligned very closely to OEB inflationary increase since 2018. The OEB's approved OM&A increase in 2018 has allowed PUC to deliver safe, reliable distribution service to its customers and return

	over the next five years, and thus will benefit consumers.”		to an ROE that is more in line with the Board Approved Cost of Capital Parameters.
2	"PUC has agreed to file the Shareholder Agreement between the City of Sault Ste. Marie and PUC Inc. dated July 25, 2000, as amended and to provide the publicly available 2017 Audited Financial Statements of PUC Services and PUC Inc."	EB-2017-0071 Schedule A pg. 9	PUC has filed the Shareholder Agreement between the City of Sault Ste. Marie and PUC Inc. and provided the publicly available 2017 Audited Financial Statements of PUC Services and PUC Inc. This was filed on September 14, 2018 as “PUC_IRR_SUPP_VECC_20180914”.
3	PUC Distribution will provide an update on the in-service date at the time of the 2022 IRM update.	EB-2020-0249 EB-2018-0219 pg. 14	As of the 2022 IRM Rate application, the in-service date of December 31, 2022 had not changed.
4	PUC Distribution shall include the approved ICM rate riders on its proposed tariff for its 2022 rate application	EB-2020-0249 EB-2018-0219 pg. 24	PUC included the approved ICM rate rider on its proposed tariff for its 2022 rate application (Eb-2021-0054 pg. 13).
5	As part of PUC 2023 rebasing application, the OEB can assess the impact of the in-service date for the Project. Per the ICM policy, if there are significant variances between the revenue requirement based on actual in-service capital and the revenues collected through the ICM rate riders, the OEB may decide to true up any differences	EB-2020-0249 EB-2018-0219 pg. 17	PUC has provided its analysis on the project amount of assets considered used and useful by December 31, 2022 and the resulting Revenue Requirement reconciliation in Exhibit 2 Section 2.8.
6	PUC Distribution shall file its next rebasing application for 2023 rates no later than August 31, 2022	EB-2020-0249 EB-2018-0219 pg. 24	PUC has filed its rebasing application by August 31, 2022.
7	File an updates DSP at the time of next rebasing application which demonstrates how the SSG project is being accommodated through the re-prioritization of other capital expenditures	EB-2020-0249 EB-2018-0219 pg. 24	PUC has filed a stand-alone DSP as an Appendix C to Exhibit 2 which includes an Asset Condition Assessment.

8	PUC Distribution shall provide a detailed report as part of its next rebasing application, which compares the SSG project costs, and benefits as implements to what was forecast in this application	EB-2020-0249 EB-2018-0219 pg. 24	PUC has updated the customer net benefit table and sensitivity analysis based on the most recently readily available information (COP rates, Cost of Capital Parameters) in the DSP as part of Section 5.3.6.2.2.
9	PUC Distribution shall file all available information on the proposed Project performance metrics that it intends to track, along with proposed targets, in its next rebasing application. This shall include an appropriate metric and targets to symmetrically link the VVO performance of the Project to PUC's allowable ROE for this project.	EB-2020-0249 EB-2018-0219 pg. 11 & 24	PUC has provided the performance metrics table within the DSP, section 5.3.6.2.3. This includes a section titled VVO Link to ROE outlining PUC's proposed methodology in connecting the VVO Savings and PUC's allowable ROE
10	PUC Distribution shall post on its public website a report, within 18 months of Project completion, and with annual updates for 10 years thereafter which shows the actual benefits of the SSG Project, broken down by customer class.	EB-2020-0249 EB-2018-0219 pg. 24	PUC is proposing to post annual updates at the same time as RRR filing deadline of April 30th yearly. The first report will be provided within 18 months of project completion and then yearly by April 30th, thereafter.
11	Any EPC Contract liquidated damages resulting from "performance" or "delay" shall be used to reduce the Project capital cost and would be settled at the time of the next rebasing	EB-2020-0249 EB-2018-0219 pg. 24	At this current time, there are no liquidated damages expected. If liquidated damages occur after the filing of this application, but before any decision is received, PUC is recommending revising the application information accordingly. If liquidated damages occur after the resulting decision, PUC is recommending the use of a DVA account to record the variance in revenue requirement as a result of the number of liquidated damages. The damages would be treated as contributed capital, thus reducing the net book value of the assets in rate base.

1.3.11 Conditions of Service & Tariff of Rates and Charges

PUC's current Conditions of Service are available for viewing on its website at https://ssmpuc.com/electricity/conditions-of-service/

PUC reviewed and updated its Condition of Service on June 30, 2022 and gave customers until August 1, 2022 to comment. Updates included various 'housekeeping' changes, and changes for greater alignment with the Distribution System Code.

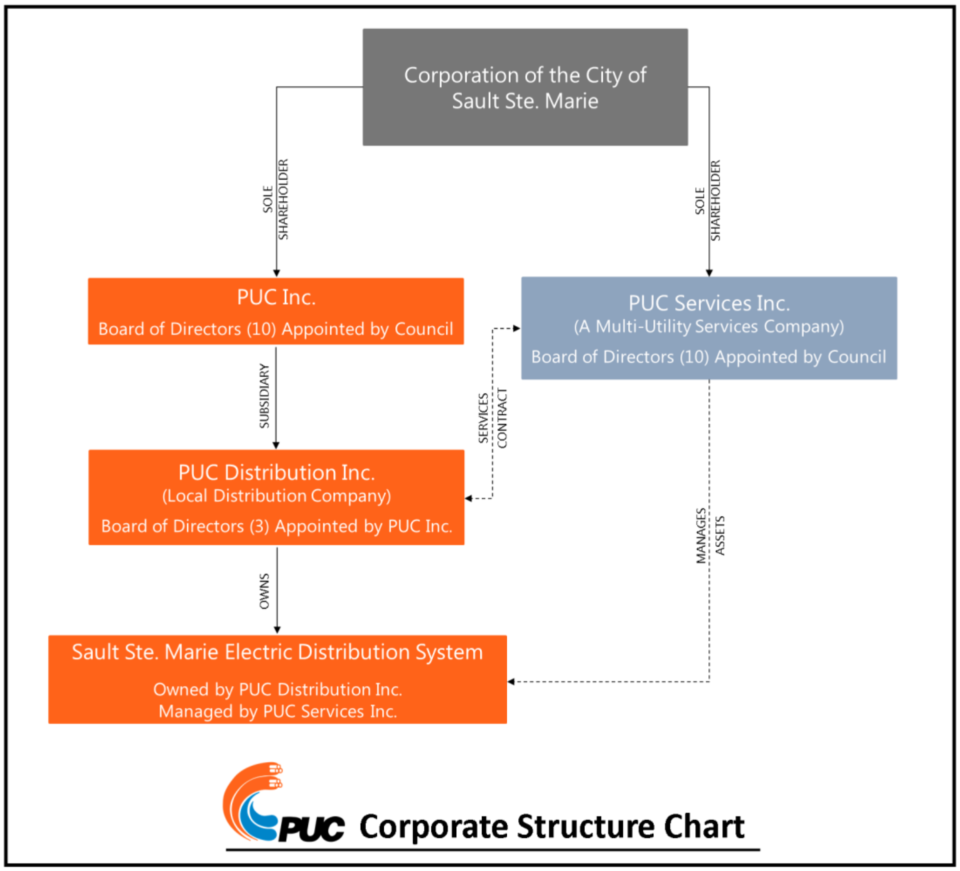
PUC did not receive any comments from customers and has provided the updated Conditions of Service to the OEB via email on August 10, 2022.

PUC confirms that there are no rates or charges listed in the Conditions of Service that are not on the Tariff of Rates and Charges.

1.3.12 Corporate and Utility Organizational Structure

PUC Inc. is a holding company that is 100% owned by its shareholder, the Corporation of the City of Sault Ste. Marie. PUC Distribution Inc. ("PUC") is a subsidiary of PUC Inc. and PUC Services Inc. is also 100% owned by the Corporation of the City of Sault Ste. Marie. There are no employees in PUC Inc. or PUC Distribution Inc. As part of a management service contract, PUC Services Inc. provides the necessary workforce to operate PUC. Collective agreements with unionized employees of PUC Services Inc. are in effect until April 30, 2024. Figure 1-1 provides a chart of the corporate structure.

Figure 1-1: PUC Corporate Structure



PUC Services Inc. is an integrated utility service provider, servicing its affiliated utility companies at cost. In addition to providing services to PUC, services are provided to the Public Utilities Commission on the same terms.

PUC Services Inc. also provides services to entities outside the affiliated group – water treatment, wastewater treatment, and billing and customer care services – under a number of contracts. These services are provided at rates negotiated between the parties, but in all cases are on a for-profit basis.

PUC is a local distribution company which provides regulated services in its service territory. The company owns the distributions assets (land and land rights, poles, conduit, conductors, transformers and meters) and operates the distribution system through an affiliated company, PUC Services Inc. Direct services from PUC Services Inc. to PUC, such as capital additions or maintenance of the distribution system, are charged at cost. Services such as billing, customer care, administration, etc., which are provided by PUC Services Inc. to all the affiliates are also charged at a cost using allocation factors based on the type of shared service provided. The fees paid by PUC to PUC Services Inc. are determined annually, in compliance with the Affiliate Relationships Code.

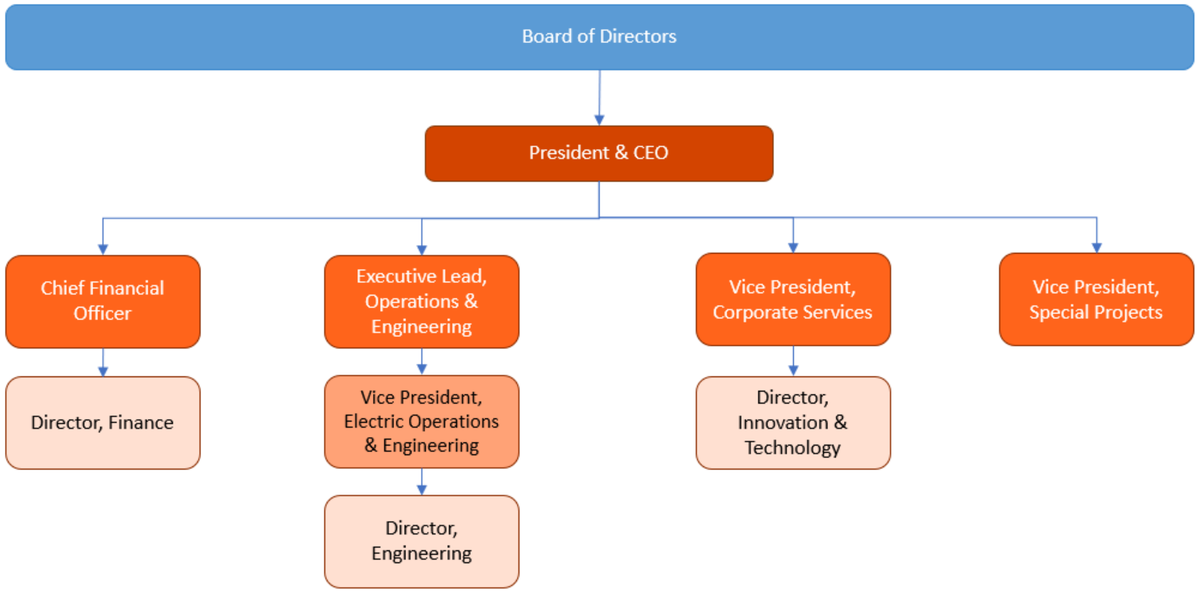
<u>PUC's Board Representation</u>

The Board of Directors of both PUC and PUC Services Inc. are appointed by City council. Currently there are 8 board members. PUC Inc. appoints 5 board members to PUC's Board of Directors, of which 3 are independent members.

The Board of Directors has the authority and obligation to protect and enhance the assets (tangible, intangible, human resources) of PUC in the interest of the stakeholders (Shareholder, customers, employees, suppliers, and community) and is responsible under law for overseeing the actions of management.

Figure 1-2 provides the organizational structure of the Senior Leadership Team of PUC. Senior leaders of the organization are made up of the Executive and Director levels.

Figure 1-2: Executive and Board Organization Chart



The Executive Team at PUC Services Inc. is comprised of the President and Chief Executive Officer (CEO), Chief Financial Officer (CFO), Executive Lead Operations & Engineering, Vice President (VP) of Electrical Operations and Engineering, VP of Corporate Services, and the VP of Special Projects. Reporting directly to the President & CEO are the Information Security and Communications teams. The CFO Division is comprised of Finance, Accounting, Billing, Regulatory Affairs and Purchasing departments. The Electric Operations and Engineering Division is comprised of Line Operations, Stations and Metering. The Corporate Services Division is comprised of IT, People & Culture, Health & Safety, Facilities, Locates and Customer Experience. The VP of Special Projects is currently leading the SSG project.

The Executives and Director roles are employed by PUC Services Inc. and allocated to PUC appropriately for its distribution services. There are no planned changes to corporate or operational structure, including no planned changes to legal organization or control.

1.3.13 List of Specific Approvals Requested

In this Application PUC is requesting the following approvals:

- Approval to charge rates effective May 1, 2023 to recover a revenue requirement of $27,752,199 which includes a revenue deficiency of $3,918,555 as set out in Exhibit 6;
- Approval of the proposed loss factor of 1.0462 as set out in Exhibit 8;
- Approval to charge a Retail Transmission Network Service rate as proposed and described in Exhibit 8;
- Approval to continue to charge Wholesale Market Service Charge;
- Approval to continue the Specific Service Charges and Transformer Allowance;
- Approval of the updated province-wide fixed monthly charge of $4.55 for Micro FIT Generator Service Classification;
- Approval of the DSP as outlined in Exhibit 2, Appendix C;
- Approval to dispose of the following 1508 Accounts, Other Regulatory Assets, associated with Sub-16 ICM Application EB-2019-0170:
    - Account 1508 Other Regulatory Assets, Sub-account Incremental Capital Expenditures;
    - Account 1508 Other Regulatory Assets, Sub-account ICM Carrying Charges
    - Account 1508 Other Regulatory Assets, Sub-account ICM Depreciation Expense;
    - Account 1508 Other Regulatory Assets, Sub-account Accumulated Depreciation;
    - Account 1508 Other Regulatory Assets, Sub-account ICM Rate Rider Revenue; and

  - Account 1508 Other Regulatory Assets, Sub-account ICM Rate Rider Carrying Charges.

- Approval to dispose of the following 1508 Accounts, Other Regulatory Assets, associated with SSG ICM Application EB-2018-0219 / EB-2020-0249:
  - Account 1508 Other Regulatory Assets, Sub-account Incremental Capital Expenditures;
  - Account 1508 Other Regulatory Assets, Sub-account ICM Carrying Charges;
  - Account 1508 Other Regulatory Assets, Sub-account ICM Depreciation Expense;
  - Account 1508 Other Regulatory Assets, Sub-account Accumulated Depreciation;
  - Account 1508 Other Regulatory Assets, Sub-account ICM Rate Rider Revenue;
  - Account 1508 Other Regulatory Assets, Sub-account ICM Rate Rider Carrying Charges;
  - Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue - Contributed Capital;
  - Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue Carrying Charges; and
  - Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue Amortization.

- Approval of the rate riders for a one-year disposition of the Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") and Lost Revenue Adjustment Mechanism ("LRAM") for lost revenue for the 2018 and 2019 program years, with persistence through 2022. This amount includes carrying charges to December 31, 2022;

- Approval of the revised rate rider refund to customers for embedded generation adjustment;
- Approval of a new DVA account associated with VVO savings and systematically linked to ROE as per the SSG ICM application deliverables (EB-2018-0219 / EB-2020-0249);
- Approval of the rate riders for a one-year disposition of the Group 1 and Group 2 and Other DVAs as detailed in Exhibit 9;
- Approval of the rate rider for the refund of Tax Loss Carry Forwards over a period of two years; and
- Approval of a new DVA account to record the difference in revenue requirement of net book value of PUC rate base if it receives liquidated damages as a result of the EPC Contract.

1.3.14 Materiality Threshold

Chapter 2 of the Filing Requirements issued by the Board on April 18, 2022 sets out the materiality levels based on the magnitude of the revenue requirement. PUC's revenue requirement is greater than $10 million and less than $200 million, therefore its materiality level is 0.5% of distribution revenue requirement. PUC's materiality threshold for the 2023 Test Year is $135,000 as provided in Table 1-17 below. PUC has used a threshold of $135,000 for assessing materiality for the purposes of this Application.

Table 1-17: Materiality Threshold for the 2018 Test Year

Description	2018 Test Year
Distribution Service Revenue Requirement	$27,654,449
Materiality Threshold	0.5%
Materiality Calculated	$138,272
Materiality Used	$135,000

1.4 DISTRIBUTION SYSTEM OVERVIEW

Description of Service Area

PUC is a local distribution company serving more than 33,000 customers in the City of Sault Ste. Marie (with exception of all or part of six municipal addresses as listed on its distribution license), Township of Prince, Rankin Reserve, and Township of Dennis (concessions 3, 4 and 5) as outlined in Figure 1-3 below.

Figure 1-3: PUC Service Area

Service Area:

	Description of the Applicant:
COMMUNITY SERVED:	City of Sault Ste. Marie (with exception of all or part of six municipal addresses as listed on its distribution license), Township of Prince, Rankin Reserve, and Township of Dennis (concessions 3, 4 and 5)
TOTAL SERVICE AREA:	342 square kilometers
RURAL SERVICE AREA	284 square kilometers
URBAN SERVICE AREA	58 square kilometers
DISTRIBUTION TYPE:	Electricity Distribution
MUNICIPAL POPULATION:	75,300

A map of PUC's service territory is provided in Appendix J.

PUC owns, operates and maintains approximately 614 kilometers of overhead primary distribution circuits, and 124 kilometers of underground primary distribution circuits.

PUC owns and operates two transformer stations which step down power received from the transmitter at 115kV to 34.5kV. The 34.5kV feeders supply a total of 14 distribution stations which step down power to 12.5kV and 4.2kV. PUC employs approximately 383,430 km of 3-phase and approximately 231,270 kms of single-phase overhead lines operating at 115kV, 34.5kV, 12.5kV, 7.2kV, 4.2kV, and 2.4kV and low voltage. The underground distribution network consists of approximately 7,573 km of 3-phase cable circuits and approximately 4,983 km of single-phase cable circuits. There are approximately 12,700 wood poles and 80 other types of poles, 6,225 transformers and 33,417 revenue meters in service.

Host/Embedded Distributor

PUC is neither a host distributor nor an embedded distributor.

Transmission or High Voltage Assets

PUC has transmission assets (>50kV) deemed by the Board as distribution assets. PUC has included the OEB determination on distribution assets dated October 3, 2000 (ED-1999-0161) in Appendix D.

PUC is not asking the OEB to deem any new transmission assets as distribution assets in this Application.

1.5 CUSTOMER ENGAGEMENT

PUC has modernized its infrastructure, innovated systems, and led the industry in projects that have had a positive impact on the way we serve customers.

1.5.1 Overview

As a trusted utility provider for over 100 years, PUC is continually looking for ways to create positive experiences for customers, while at the same time encouraging behaviour that is more responsive to energy conservation. PUC is always striving to use innovation to improve communication and trust with customers. PUC recognizes that as the utility industry evolves, so do their customers' needs and expectations.

PUC's five-year strategic direction provides clarity, direction and focus connecting PUC's vision to improve communities through curiosity and innovation, with the company's core strategies and strategic objectives. Customers are one of PUC's three areas of strategic focus, along with employees and PUC's shareholder. PUC's strategic long-term goal is to achieve and maintain an exceptional satisfaction rating, and strategies to achieve success in this area include advancing customer communications and engagement, and creating an improved, ease of use experience.

Over the past five years, improving communications, community relations and the overall customer experience have been identified as strategic priorities for the company. Through this focused approach, PUC has been able to effectively engage with customers through meaningful, two-way communication, and improve upon the customer experience through a "one-stop-shop" methodology for first point of contact.

In 2020, PUC developed a new brand promise to customers that states "*we lead the way through innovation and compassion to deliver outstanding service every single day*." Combined with PUC's core value of being 'customer-centric,' PUC has continually demonstrated their commitment to engaging customers over the past five years.

The following sections outline the various communication tactics under 'Digital,' 'Traditional' and 'Community Outreach' that PUC has implemented to best serve its customers.

1.5.2 Communication Tactics

Digital

Enhancing Digital Platforms

PUC is leveraging digital technology to facilitate and improve customer communications. The result has been improved integration through a variety of technologies (App, social media, etc.) into PUC's channel portfolio to improve customer communication and engagement, while at the same time reducing PUC's carbon footprint. PUC recognizes that companies who embrace digital communication also see higher levels of engagement from their customers; digital communication is a core element of a good customer experience strategy. PUC's digital strategies, such as its mobile App, website, video, social media, and digital advertising, are easier to measure, adapt and optimize, and are often more cost efficient with a larger reach than traditional methods.

i. Mobile App

Today's customers are looking for fast, easy avenues through which they can gather information and manage their accounts, while conserving energy and saving money. One available solution to improve a customer's experience is to develop a 'free to user' branded mobile App. Overall, in the utility industry, the emerging trend in this area is that more utilities are using mobile Apps to support demand response and energy efficiency efforts.

This initiative not only follows current industry trends, but it also responds to many of PUC's customers who have inquired about the availability of a PUC app to receive up-to-date information (i.e., outage alerts) and the ability to manage their accounts. An App is aligned with strategic goals of the company related to conservation management and efforts to go paperless.

Through public consultation, customers told PUC they wanted a mobile communications solution that made it easier to manage their usage and accounts, receive up-to-date information on power and enable two-way communication.

In 2021, PUC identified this as an opportunity to develop and market a mobile app ("MyPUC') that would do all of the above and more.

Through an effective communications plan, 3,360 customers (as of August 2022) are now using the MyPUC App. It has allowed customers to submit outage tips to PUC's customer experience team quickly and easily, allowing PUC to respond and repair outages quicker.

Conservation tips, price plan comparisons and daily and historical data usage are available to customers to help them reduce their energy consumption, and ultimately save money. PUC recently introduced a 'Green House Gas (GHG)' page that easily displays customers' GHG output based on their recent bill. In addition, when customers download and activate the MyPUC App, they are also enrolled in e-billing. This saves PUC and ratepayers money and helps PUC achieve the five-year goal to go paperless.

ii. Website

To improve customer ease of use, PUC has made ongoing updates and improvements to its company website, www.ssmpuc.com. The website is a user-friendly site that provides information on planned and unplanned power outages, news items, information on electrical safety tips, electricity rates, conditions of service, Ontario Energy Board (OEB) scorecard, and other information such as updates on SSG.

Ongoing improvements to the site also included new online forms to make it easier for customers to do business with PUC. Examples include the 'moving within service area' form, 'close account' form and 'new customer' form. Customers can also report issues online in a quick and easy fashion, such as street light outage and tree trimming requests through the 'Report an Issue' section of the website. In addition, the site contains easy to find links to the Customer Connect portal and social media sites. Customers can also sign up for PUC's email distribution list through the website.

iii. Customer Connect Portal

PUC customers have access to a secure online service portal, 'Customer Connect.' The portal allows customers to easily access account information, view current and past bills, view account payment history, keep track of utility consumption history and conservation efforts and enroll in e-billing.

PUC has increased the production and use of video to communicate effectively with customers. Video allows PUC to tell its story, while providing visually appealing images that appeal to a segment of PUC customers.

In 2019, PUC launched the ***Day in the Life Video Series*** that documented the operations of several PUC departments. The stories in the videos are told through the lens of PUC's team members. The videos have created an opportunity for PUC to increase understanding and awareness of PUC's operations.

iv. Social Media

PUC has implemented a comprehensive social media strategy, which includes regular customer engagement on Facebook, Twitter, LinkedIn and YouTube. PUC uses Sprout Social to manage the accounts and measure the effectiveness of the platforms.

Customers are able to send messages directly to PUC Communications through Facebook and Twitter. Messages are responded to in a timely fashion, and act as another communications tool customers can take advantage of. Social media accounts are also used to update customers on power outages, news, contests, safety reminders, cultural days, days of recognition, community engagement events, and more.

Figures 1-4 and 1-5 below demonstrate the growth in followers on PUC's Facebook and Twitter pages.

Figure 1-4: Facebook Followers Growth

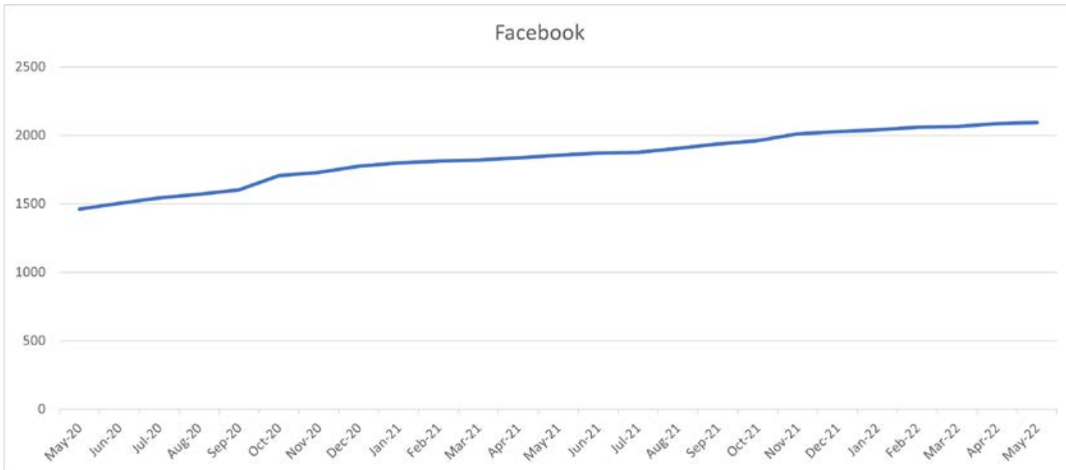
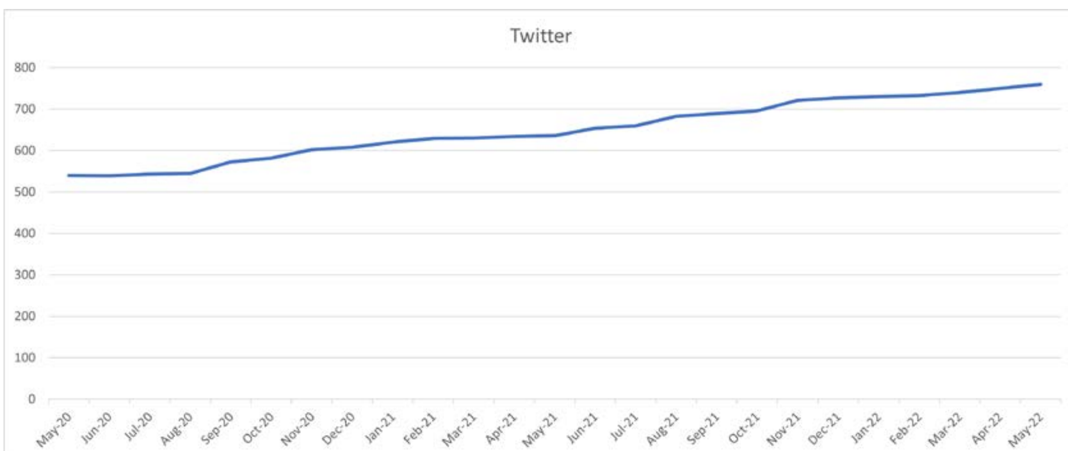


Figure 1-5: Twitter Followers Growth



v. Digital Advertising

PUC uses digital awareness campaigns as another method of communicating with customers.

Traditional

In addition to the digital communications outlined above, PUC continues to provide customers with options that suit their lifestyle. While PUC aims to transition to digital and reduce their carbon footprint, it is understood that customers want choice and PUC accommodates individual needs and preferences.

Phone and Mail

PUC continues to reach out to customers via Customer Experience department phone calls, personalized letters, bill inserts, and hand delivered door-to-door notices. In addition, PUC uses its ATLAS phone notification system to send out automated phone calls to customers in the event of a planned power outage, or other messages that are program related, for example, to those customers who participated in the Affordability Fund Trust program.

Traditional Media

PUC has continued to use traditional media tactics, such as press releases, media advisories and press conferences to inform customers of power outages, news updates, customer warnings, safety messages, etc. PUC works with local outlets such as Sootoday.com, CTV News Northern Ontario, Sault Online, and the Sault Star (among others) to get messages out to customers in a timely and effective manner.

PUC also held press conferences (i.e., Sub-16 opening, SSG updates) to inform customers of important announcements, infrastructure renewal projects, and other issues that may impact them.

Print and Radio Advertising

PUC places ads on the radio and in print, as another method of communicating with customers.

Community Outreach

It is important that PUC have a physical presence in the communities it serves. Connecting with community members is vital to PUC's communication and engagement strategy. Significant efforts have been made to get PUC employees out in the community on a more regular basis to interact with customers face-to-face and receive input. The COVID-19 pandemic had a negative impact on these efforts in 2020-2021, however, virtual events were held, as discussed under the section 'Town Halls & Open Houses'. Further, throughout the pandemic, PUC took a leadership role in the community by donating KN95 masks and other PPE to the Sault Area Hospital and promoting vaccine clinics though the Algoma Vaccination Support Council. PUC created a new program that saw the company organize and pay for taxi rides for those needing transportation to their vaccine appointment. PUC also supported volunteers who ran the numerous vaccine clinics by paying for their lunches and dinners and supplying them with volunteer clothing. PUC is dedicated to one of its most proud slogans "PUC Cares".

Attendance at Community Events

PUC has increased attendance at community events significantly over the past five years. Most recent events include participating in the Community Rotary Fest, Community Festival of Trees, PUC Lights Up Downtown and the Emergency Preparedness Showcase. *(see Appendix K for more information).*

Town Halls & Open Houses

PUC has hosted several town halls and open houses including the Emergency Preparedness Event in 2020. Due to the COVID-19 pandemic, PUC adapted the way in which we delivered open houses and held several open houses and public information sessions related to various projects (*see Appendix K for more information).*

School Safety Program

PUC's commitment to safety extends to the communities it serves and begins with youth. For over 25 years, PUC has delivered the Caution and Chance Program to local schools (grades three to five) across the Sault Ste. Marie community. This program is an interactive electrical presentation, taught by knowledgeable members of the PUC team who have worked in the utility industry for many years.

As a partner in school safety, this initiative provides education on electrical safety awareness, thereby increasing knowledge of potential electrical hazards and encouraging a respect for electricity. PUC is committed to educating youth in the community and fostering a positive understanding of electrical hazards. By cultivating a healthy relationship with electricity at a young age, children will learn to respect and have knowledge of potential dangers with electrical energy.

Over the past five years, PUC has continued to deliver the 'Caution and Chance' Safety program in elementary schools, reaching hundreds of students each year. Unfortunately, the COVID-19 pandemic had a negative impact on delivery of the program in 2020 and 2021. In 2022, a School Safety Award was introduced and given to 13 graduating grade 8 students, recognizing outstanding commitment to safety in their schools.

Electrical Safety Awareness Training

As a community partner, the safety of PUC's fellow community members is a top priority. In 2019, PUC offered electrical safety awareness training for educational purposes to workplaces in the City of Sault Ste. Marie. PUC powerline technicians provided the training to increase knowledge about hazards when working around electricity. The goal was to provide workers with a heightened level of electrical awareness, so that those who may work near electrical circuits or equipment can do so safely and effectively. The training is customized to each workplace and workers are left with the knowledge of how to manage potential work area electrical hazards.

Affordability Fund Trust

The mandate of the Affordability Fund Trust ("AFT") program was to make energy more affordable for the Fund's beneficiaries – Ontarians who do not quality for low-income programs, but who want to conserve energy to reduce their electricity bills now and in the future.

PUC identified the Ontario government's AFT program as a tangible and effective way to support its customers. The program provided an opportunity for local electricity distributors and utilities to help customers reduce their hydro bills. While the province funded the program, it was up to individual utilities to make their customers aware of the program and encourage them to sign up. Because of an effective, inclusive communications and engagement plan, PUC had by far the highest per capita benefit in Ontario for the program. From 2017 to 2021, PUC delivered the program to 6,811 customers.

1.5.3 Investing in Improvements to the Customer Experience

One-stop-shop

In 2019, PUC changed how customers interacted with the Customer Experience (call centre) team by creating a 'one-stop shop' structure for customer's first point of contact. Previously, when customers called regarding issues relating to billing and collections, they were transferred to a different department, causing confusion and longer response times for customers. In order to make a more positive experience for customers, all Customer Experience clerks were trained to handle issues with billing and collections, so customers would no longer need to be transferred. The result has been an improved process for customers at first point of contact.

Electronic Billing

PUC continues to promote Electronic billing (e-billing) as a way to improve the overall customer experience, while at the same time reducing the use of paper and PUC's carbon footprint. E-billing makes it easy for PUC customers to receive bills online via the Customer Connect portal, MyPUC App or e-mail, and pay electronically. PUC has established a quick, 7-step sign-up process to ensure a smooth transition for all customers. Customers who sign-up for the MyPUC App are automatically enrolled in e-billing unless they opt-out of that feature. PUC has run several communication campaigns to encourage PUC customers to enroll in e-billing. One such campaign donated money to the 'Every Breakfast Counts' charity for every new enrollment. To date, over 25% of PUC customers are now enrolled in e-billing.

1.5.4 Customer Surveys

Through regular customer engagement surveys, PUC has been able to incorporate important customer feedback when evaluating PUC's priorities moving forward. Surveys have also provided opportunities for education and awareness regarding PUC's operations, improvements to service and strategic initiatives.

Since PUC's 2018 COS filing, it has engaged customers in the following eight surveys:

- Two UtilityPULSE Customer Satisfaction Surveys (2019, 2021);
- Four Customer Pulse surveys (in 2020); and
- Two Cost of Service-related surveys (2021, 2022).

As each survey is analyzed, several common themes have surfaced, providing PUC with greater insight into the needs and wants of customers. Those common themes include:

- Customers want improved communications;
- Customers place a high value on energy saving initiatives and PUC lowering their carbon footprint;
- Customers place a high value on reliability, cyber security and upgrades to infrastructure; and
- Customers place high importance on reasonable electricity rates.

Below provides a more detailed summary of the surveys conducted, and how PUC has responded.

As part of ongoing efforts to improve customer engagement, the proposals in the COS application were communicated with customers via an online customer engagement survey conducted during a three-week time period between May 20 and June 10 , 2022. The purpose of the survey was to provide customers with information on the proposed rate increase, along with the opportunity to share feedback into future investment decisions for PUC, ultimately informing PUC's 2023 COS application.

The survey was communicated with customers via several different methods, including e-mail, digital ads on PostMedia networks (e.g. Sault This Week, Sault Star), Sault Online and Sootoday, as well as ads on social media (Facebook and Instagram). In total, the ads received a reach of over 150,000 people through various online channel and local media. This resulted in 816 residential and commercial customer who completed the survey in its entirety.

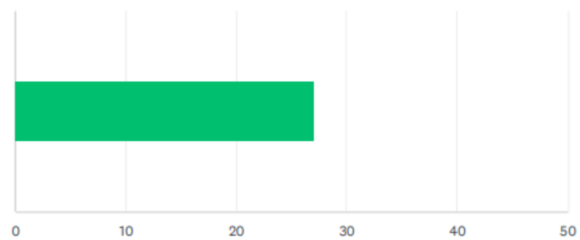
Information within the survey stated, "If PUC's application to the OEB is approved, a current 750kWh avg. residential electricity bill of $122.56 would increase by approximately $3.19 per month or 2.6%." The survey also included educational information on the COS Application, updates on how PUC is investing in infrastructure to improve reliability and communications, and PUC's bill breakdown. Within the survey, customers were asked questions specifically related to the application, such as the following: "PUC is committed to keeping our portion of your bill affordable, while providing safe and reliable electricity. As previously mentioned, cost increases and infrastructure investments will result in a rate increase for PUC Customers; estimates at this time are an approximate increase of $3.19/month on a $122.56 bill for an average residential customer. On a sliding scale, please let us know what is more important to you?"

As depicted in the graph below, customers responded that both keeping PUC's portion of the bill affordable and providing safe and reliable electricity are important to them.

<u>Figure 1-6: Survey Results Investments in Infrastructure Question</u>

Q4 PUC is committed to keeping our portion of your bill affordable, while providing safe and reliable electricity.As previously mentioned, cost increases and infrastructure investments will result in a rate increase for PUC Customers; estimates at this time are an approximate increase of $3.19/month on a $122.56 bill for an average residential customer.On a sliding scale, please let us know what is more important to you?

Answered: 816 Skipped: 0



ANSWER CHOICES	AVERAGE NUMBER	TOTAL NUMBER	RESPONSES
	27	22,068	816
Total Respondents: 816			

In addition, based on the results of this survey, it was noted that PUC should focus its priorities on delivering reasonably priced electricity prices and ensuring safe and reliable electricity services, provide a variety of options for customers when accessing services, with a focus on online tools, and provide both reliable information and services regarding the adoption of electric vehicles.

The feedback collected from this survey has informed the application in a number of ways. By making significant investments in the SSG, PUC has made major efforts to keep the proposal rate increase as low as possible. Once operational in 2023, over time, the SSG will result in a more reliable system and average energy savings of 2.7%. If PUC’s application to the OEB is approved, a current 750kWh avg. residential electricity bill of $122.56 would increase by approximately $3.19 per month or 2.6% - below the approx. 7.7% inflation environment.

Not only is PUC making efforts to help customers reduce their energy costs, PUC is making unprecedented investments in customer service tools and aging infrastructure that will result in increased reliability today - and well into the future. For example, PUC's new MyPUC App now allows customers to track energy consumption in an easy and convenient way, resulting in better energy management and lower bills. PUC is also renewing and replacing important assets like aging infrastructure, resulting in safer and more reliable service.

Finally, PUC is electrifying its fleet, and exploring opportunities that would promote use of electric vehicles within and around the community. This aligns with Canada's commitment to mandating all new light-duty vehicles sold be zero-emission by 2035, with an interim sales target of at least 50 percent by 2030.

UtilityPULSE Customer Satisfaction Surveys

In 2019 and 2021, PUC conducted its biennial Customer Satisfaction Surveys with UtilityPULSE. The objective of these surveys is to capture perceptions about customer needs and wants as well as gather information to support discussions and improve the customer experience at every level in the organization.

2019 Summary (Appendix F)

During the period of September 2019, 400 customers completed a telephone interview, providing a confidence level of 95% (+/- 4.9%). The survey represented 85% residential and 15% commercial.

PUC received a Credibility and Trust Rating of 87% and an Overall Satisfaction Rating of 94%. From this survey, customers expressed that the following should be priorities for PUC:

- Pro-actively maintaining and upgrading equipment;
- Reducing response times to outages;
- Investing in projects to reduce the environmental impact of the utility's operations; and
- Investing more in the electricity grid to reduce outages.

Based on this feedback, PUC has made significant investments through the SSG project that will result in upgrades to equipment, a reduction in the response times to outages, a reduction in the number of outages and a reduction of PUC's environmental impact through more efficient energy consumption. In addition, PUC has purchased electric vehicles and developed a plan to further electrify their fleet to lower maintenance and fuel costs and lower their carbon footprint.

2021 Summary (Appendix F)

During the period of September 2019, 401 customers completed a telephone interview, providing a confidence level of 95% (+/- 4.9%). The survey represented 85% residential and 15% commercial.

PUC received an A rating. PUC received a score of 83% on the customer centric engagement index (CCEI), compared to 82% in Ontario.

From this survey, customers expressed that the following should be priorities for PUC:

- Movement to more digitization;
- Improvements to communication (more pro-active approaches);
- Better prices and lower rates;

- Simplified billing; and
- Enhance cyber security measures.

Based on this feedback, PUC has put in place a digitization strategy, with a goal of going paperless by 2024. Since the initiative was launched in 2019, PUC has reduced day-to-day printing dramatically, increased on-line payments to vendors, enhanced the customer experience by providing flexibility, and restructured processes internally for employees to promote efficiencies. Some specific examples include the promotion of e-billing for customers, the development of the MyPUC App, the elimination of printed paystubs, an increase in Electronic Fund Transfers from 8% to over 82%, and the development of an online self-serve employee portal.

PUC has improved pro-active communications through the development of the MyPUC App, and the increased use of social media platforms and PUC's website. For example, in addition to ATLAS phone notifications, the MyPUC app and website now display information on planned power outages in advance, so that customers can properly prepare for the interruption.

PUC recognizes the threat that cyber security represents and is taking measures to mitigate that risk. PUC has made significant investments in our cyber security infrastructure, including the addition of a Manager of Information Security. Cyber risk is PUC's #1 risk and due to its significance, the President & CEO is the accountable Risk Owner.

In order to simplify billing, PUC has continued to encourage customers to sign up for preauthorized payments, e-billing and the MyPUC App.

Lastly, PUC has made significant investments through the SSG project that will result in customers saving approximately 2.7% of their energy consumption.

Customer Pulse Surveys

2020 Summary & Results (Appendix F)

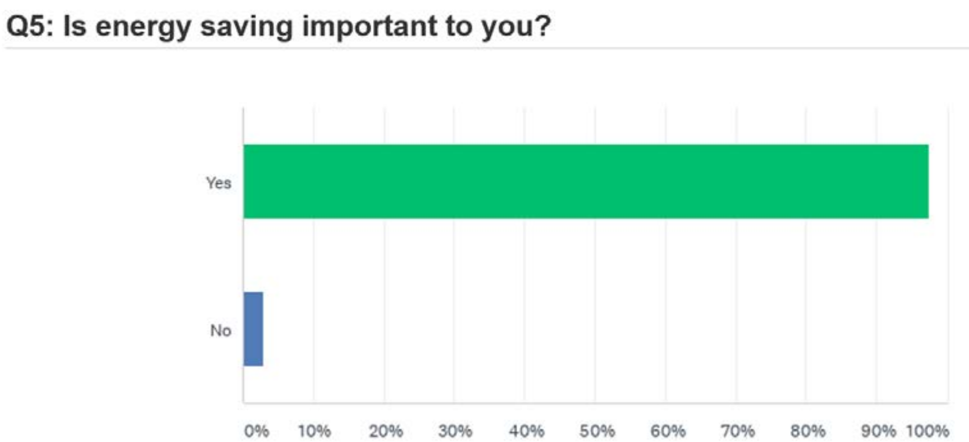
In 2020, PUC conducted four online pulse surveys throughout the year to provide education and gain insight into how to better serve customers related to PUC's strategic and long-term planning. The message to customers was as follows:

"New Advances in technology are changing the way we distribute electricity, and as a result, are providing new options for customers. With new technologies, customers will be better equipped to exercise more control on their energy consumption, and technological advances mean safer options and an eventual decrease in the price of electricity. All of this is possible, but it requires investments today so electricity will continue to be safe, reliable, and affordable for tomorrow."

Based on the results of those surveys, it was noted that PUC should:

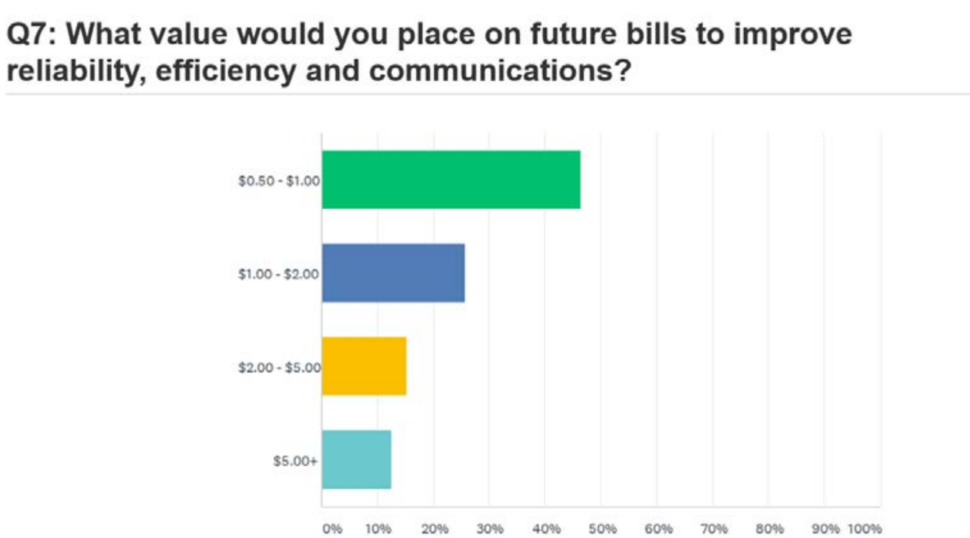
Look at ways to create energy savings for customers. The graph below displays this, as 97.39% of customers state that energy savings is important to them.

Figure 1-7: Survey Results Energy Savings Question



Consider increasing bills, if it means improvements to reliability, efficiency and communications. The graph below displays this, as 72.12% customers stated they would place a value between $0.50 - $2.00 on future bills to improve reliability, efficiency and communications.

Figure 1-8: Survey Results Value of Communication Question



Make major investments in how PUC operates to reduce their carbon footprint. The first graph below displays that 60% customers stated reducing PUC's carbon footprint by making major investments in how it operates is either extremely or very important. The second graph below displays that 67% of customers stated that it is either extremely important or very important that PUC play a role in the community to promote the reduction of greenhouse gas emissions.

Figure 1-9: Survey Results Carbon Footprint Question

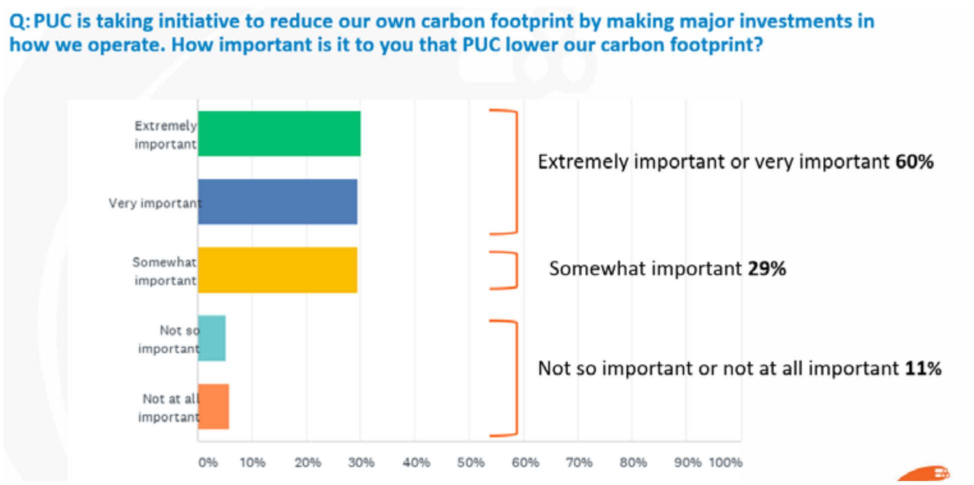
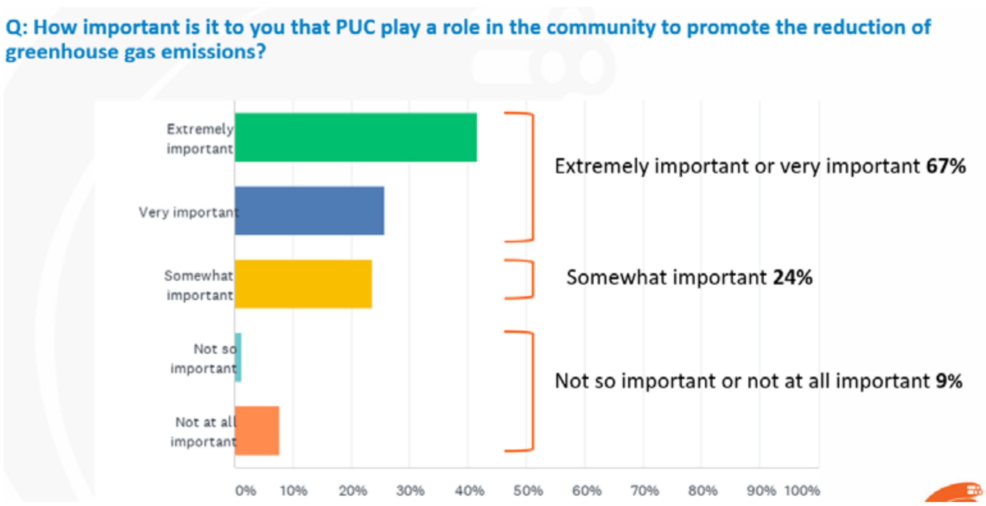
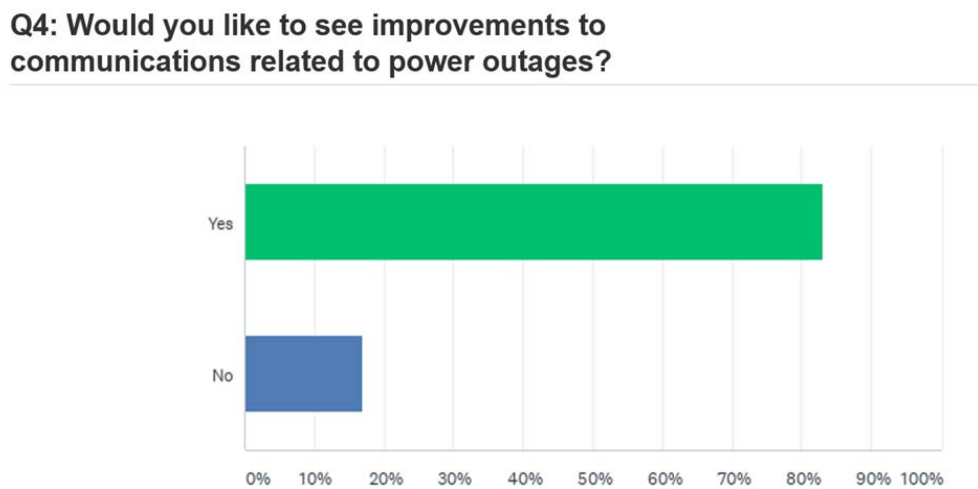


Figure 1-10: Survey Results Greenhouse Gas Emissions Question



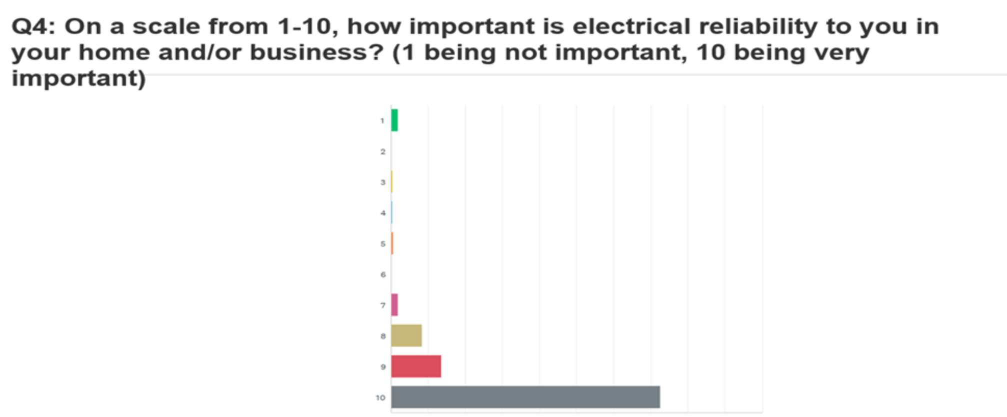
Improve and enhance the customer experience. The graph below displays that 82.95% of customers stated they would like to see improvements to communication related to power outages.

Figure 1-11: Survey Results Power Outage Communication Question



Look at ways to improve electrical reliability. The graph below displays that 72.64% of customers rated reliability as a 10 (on a scale from 1-10, 10 being the most important).

Figure 1-12: Survey Results Reliability Question



Based on this feedback, PUC is making significant investments through the SSG project that will result in upgrades to equipment, a reduction in the response times to outages, a reduction in the number of outages and a reduction to PUC's environmental impact through more efficient energy consumption. In addition, PUC has purchased electric vehicles and developed a plan further electrify their fleet to lower maintenance and fuel costs and lower their carbon footprint.

Through the increased use of social media platforms and website, and the development of the MyPUC App, PUC has made major efforts to be more proactive with customer communications. For example, in addition to ATLAS phone notifications, the MyPUC app and website now display information on planned power outages in advance, so that customers can properly prepare for the interruption.

<u>Cost of Service-related Surveys</u>

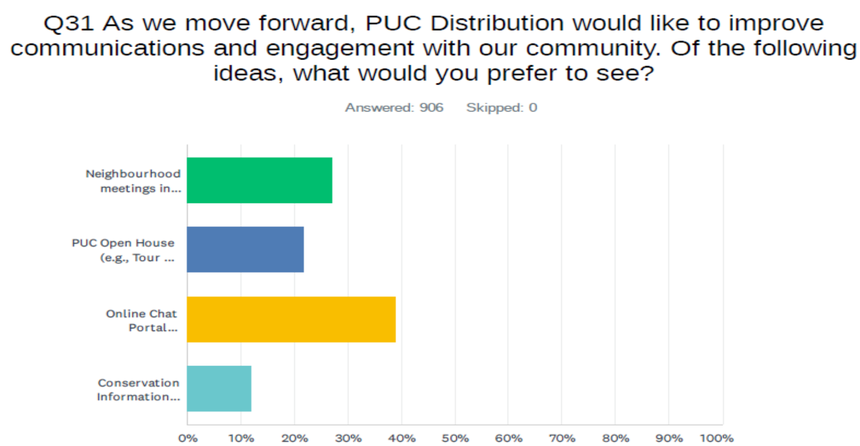
In 2021 and 2022, PUC conducted two online Customer Engagement Surveys. The purpose of the surveys was to provide customers with a better understanding of the details behind PUC's proposed rate increase, along with an opportunity to share their feedback into future investment decisions at PUC which will inform PUC's 2023 COS Application.

2021 Summary (Appendix L)

The first survey (part one of two), attached as Appendix L, was conducted in August-September 2021. 906 customers completed an online survey. Based on the results of this survey, it was noted that PUC should:

Explore more options for customer communications and energy savings tools. The graph below shows that 38.96% of customers would like PUC to move ahead with an online chat portal. The second graph below shows that 74.56% of customers would be interested in tools to help decide between tiered and time-of-use pricing. The third graph below shows that 44.12% of customers would like a notification when they hit certain consumption levels. All of these examples reflect customer's desire for new tools to support customer communications and energy savings.

<u>Figure 1-13: Survey Results Improved Communication Options Question</u>



ANSWER CHOICES	RESPONSES	
Neighbourhood meetings in advance of planned projects	27.15%	246
PUC Open House (e.g., Tour PUC facilities)	21.85%	198
Online Chat Portal (Connected to PUC website)	38.96%	353
Conservation Information Booths (e.g., Bushplane Days, RotaryFest)	12.03%	109
TOTAL		906

Figure 1-14: Survey Results TOU vs. Tiered Pricing Tools Question

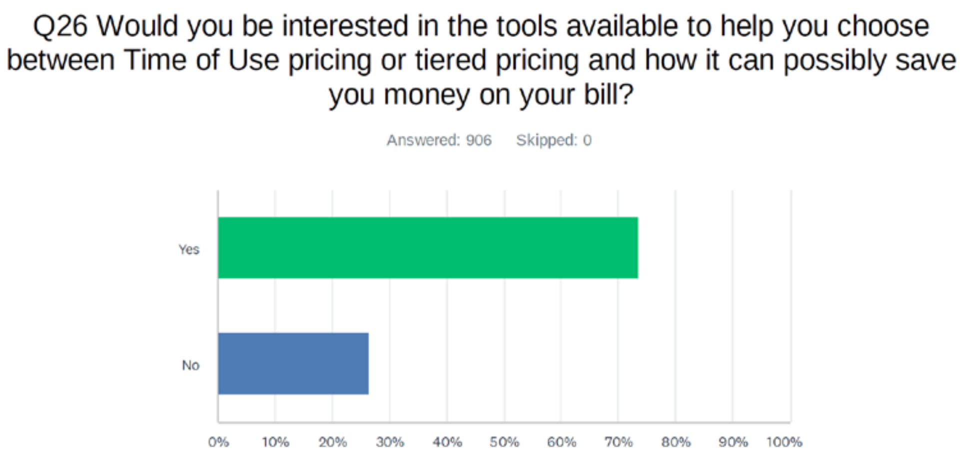
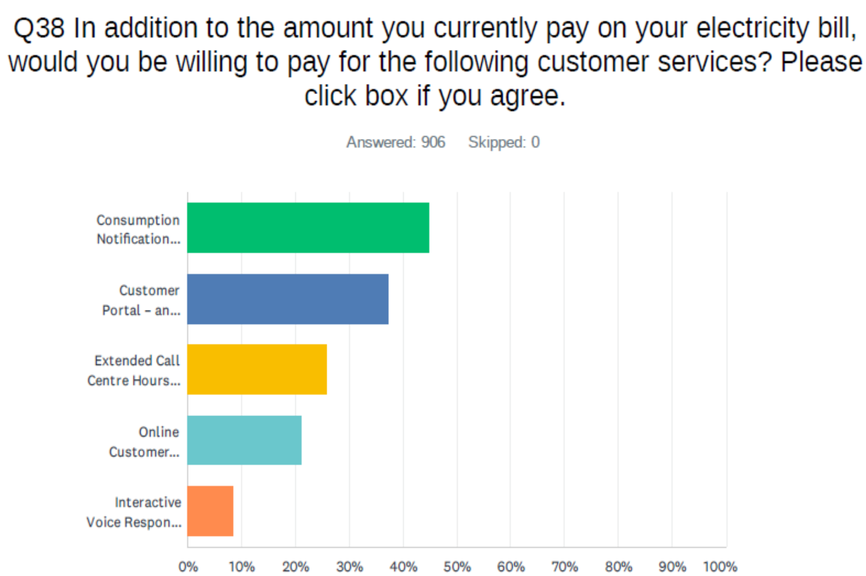


Figure 1-15: Survey Results Customer Service Question



ANSWER CHOICES	RESPONSES	
Consumption Notification – getting notified via email, text alert when consumption hits certain level	44.92%	407
Customer Portal – an updated customer portal giving more detailed information on Billing, Usage, Outages, etc.	37.31%	338
Extended Call Centre Hours beyond M-F 9:00am – 4:30pm (i.e. 7 days a week 9:00am-9:00pm)	25.72%	233
Online Customer service – live chat with customer service representative during M-F 9:00am – 4:30pm	21.08%	191
Interactive Voice Response – telephone system that allows our computer system to interact with customer through a telephone keypad, providing account status, and outage updates	8.61%	78
Total Respondents: 906		

PUC should invest in maintaining reliable electricity services. The graph below shows that maintaining reliable electricity services is the number one priority for customers.

Figure 1-16: Survey Results Summary

	1	2	3	4	5	6	7	8	TOTAL
Maintaining reliable electrical service (i.e. prevent/reduce power outages)	49.78% 451	21.30% 193	14.02% 127	5.74% 52	3.42% 31	2.21% 20	1.21% 11	2.32% 21	906
Helping customers reduce/manage consumption and by doing so reducing bills	14.57% 132	34.11% 309	21.41% 194	14.35% 130	6.95% 63	4.53% 41	2.21% 20	1.88% 17	906
Keep rates as low as practical while maintaining good quality electrical service	23.07% 209	24.39% 221	29.25% 265	13.13% 119	5.96% 54	2.21% 20	0.99% 9	0.99% 9	906
Community Engagement/Communication	1.43% 13	3.64% 33	9.38% 85	25.39% 230	16.00% 145	13.80% 125	12.14% 110	18.21% 165	906
Ensuring safety of the electrical system infrastructure	5.74% 52	8.61% 78	11.04% 100	17.77% 161	32.12% 291	16.56% 150	6.29% 57	1.88% 17	906
Providing more information during power outages	1.55% 14	2.87% 26	5.41% 49	10.71% 97	17.66% 160	37.31% 338	16.56% 150	7.95% 72	906
Modernizing the electrical system (e.g. electric vehicles, net-metering, etc.) to support the reduction of greenhouse gases and lessen climate change.	2.54% 23	3.31% 30	6.51% 59	8.06% 73	12.03% 109	12.47% 113	38.85% 352	16.23% 147	906
Providing Enhanced Customer Service (mobile app, customer connect, PUC website)	1.32% 12	1.77% 16	2.98% 27	4.86% 44	5.85% 53	10.93% 99	21.74% 197	50.55% 458	906

Based on this feedback, PUC is making significant investments through the SSG project that will result in upgrades to equipment, a reduction in the response times to outages, a reduction in the number of outages and a reduction PUC's environmental impact through more efficient energy consumption. In addition, PUC has purchased electric vehicles and developed a plan to further electrify their fleet to lower maintenance and fuel costs and lower their carbon footprint.

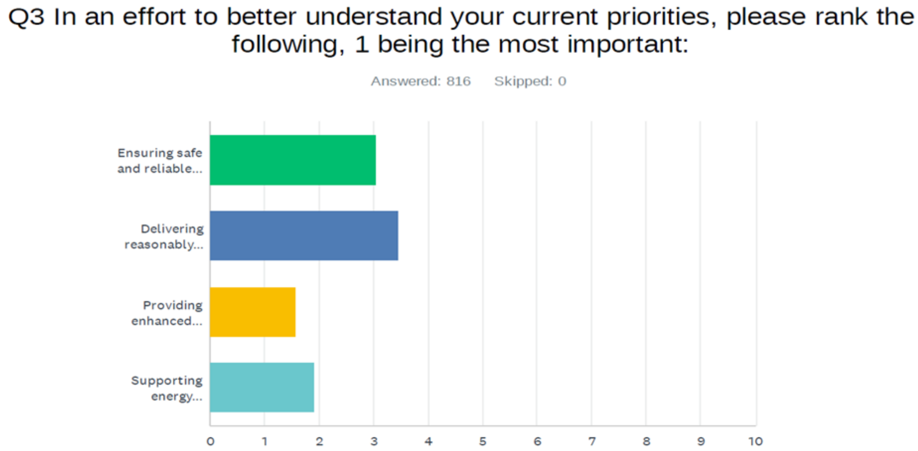
Improved communications through proactive measures like the MyPUC App, website tools and more consistent use of social media platforms, PUC has been able to get in front of issues (including outages) for a better overall customer experience. Customers can now access information on planned outages, news updates, changes in electricity rates, etc. on multiple platforms, thereby improving a customer's overall experience with PUC.

2022 Summary (Appendix M)

Building from the results of the first survey, the second survey, attaches as Appendix M, (part two of two) was conducted in May-June 2022. 816 customers completed an online survey during a three-week time period between May 20th and June 10th 2022. Based on the results of this survey, it was noted that PUC should:

Focus its priorities on delivering reasonably priced electricity prices and ensuring safe and reliable electricity services. The graph below displays that 92.15% of customers ranked either delivering reasonably priced electricity prices or ensuring safe and reliable electricity services as their top priority.

Figure 1-17: Survey Results Customer Priorities Question



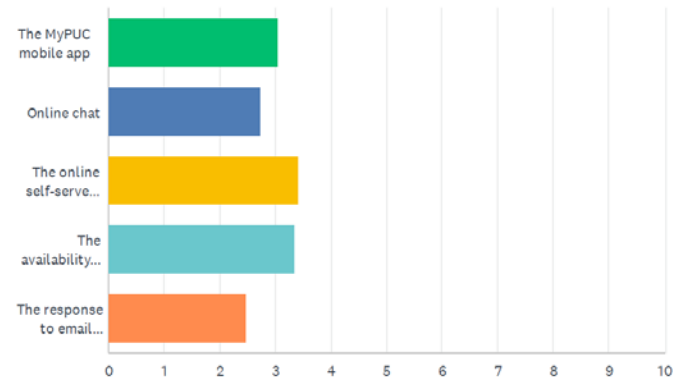
	1	2	3	4	TOTAL	SCORE
Ensuring safe and reliable electricity services	32.84% 268	44.73% 365	17.28% 141	5.15% 42	816	3.05
Delivering reasonably priced electricity services	59.31% 484	30.02% 245	7.97% 65	2.70% 22	816	3.46
Providing enhanced customer service	2.08% 17	7.84% 64	36.15% 295	53.92% 440	816	1.58
Supporting energy efficiencies and a lower carbon footprint	5.76% 47	17.40% 142	38.60% 315	38.24% 312	816	1.91

PUC should provide a variety of options for customers when accessing services, with a focus on online tools. In the graph below, customers noted that the MyPUC mobile app, the online self-serve options for managing their account and the availability of call centre staff are the most important options when accessing services.

Figure 1-18: Survey Results Customer Convenience Question

Q5 PUC has made it an ongoing strategic priority to improve our customer's experience. As it relates to the convenience of accessing customer services, please rank the following in order of importance.

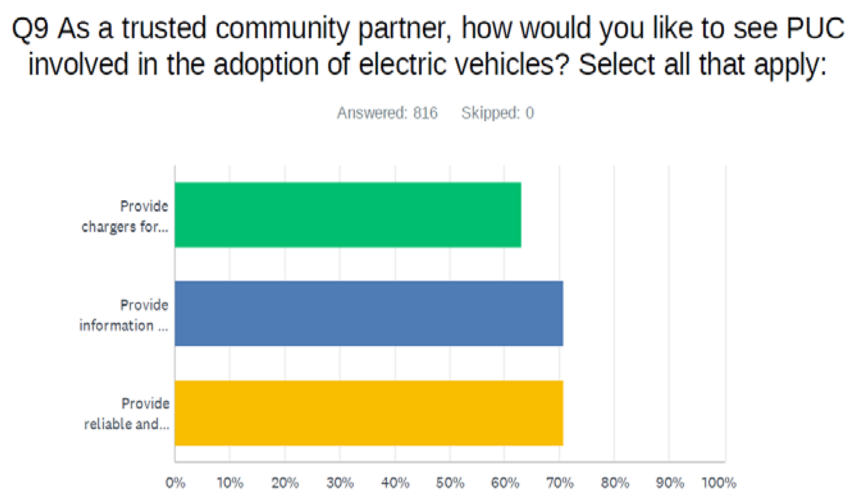
Answered: 816 Skipped: 0



	1	2	3	4	5	TOTAL	SCORE
The MyPUC mobile app	26.35% 215	18.01% 147	14.22% 116	16.30% 133	25.12% 205	816	3.04
Online chat	6.62% 54	21.69% 177	28.31% 231	24.51% 200	18.87% 154	816	2.73
The online self-serve options for managing your account (Customer Connect)	26.59% 217	23.04% 188	25.12% 205	16.54% 135	8.70% 71	816	3.42
The availability of call centre staff	33.95% 277	16.42% 134	14.83% 121	19.00% 155	15.81% 129	816	3.34
The response to email questions	6.50% 53	20.83% 170	17.52% 143	23.65% 193	31.50% 257	816	2.47

PUC should provide both reliable information and services regarding the adoption of electric vehicles. In the graph below, 63.11% of customers stated they would like PUC to provide chargers for residential and commercial customers through rental or purchase programs, and 70.71% and 70.83% would like PUC to provide information on government incentives and more general reliable information on electric vehicles, respectively.

<u>Figure 1-19: Survey Results Electric Vehicles Question</u>



ANSWER CHOICES	RESPONSES	
Provide chargers for residential and commercial customers through rental or purchase programs	63.11%	515
Provide information on Government programs and incentives for the purchase of electric vehicles and chargers	70.71%	577
Provide reliable and accurate information about electric vehicles and chargers	70.83%	578
Total Respondents: 816		

By having a presence in the community, developing and improving upon communication channels and engaging customers through meaningful surveys, PUC has been able to effectively gather information from customers when making decisions. Improving upon the overall customer experience has been a top priority for PUC over the past five years, as demonstrated by the many innovations and improvements that have been made. Ensuring that customer voices are heard has pushed PUC leadership to be innovative and make smart decisions that are in the best interests of its customers, its employees and its shareholder.

1.5.5 Response to Customer Preferences

Many steps have been taken to increase customer engagement. PUC has adopted a customer-centric (core value) approach that will continue to build trust with customers and provide services based on customer needs and priorities. Through multiple customer engagement methods, PUC has provided customers opportunities to share their priorities. PUC will continue with these engagements to listen to customer preferences as the company evolves.

During the customer engagement activities, the PUC's engineering team heard feedback received from customers during the engagement phase of the DSP planning work. The DSP was developed to ensure that the rate increases were minimized, while considering the Asset Management Plan for necessary system renewal projects in order to maintain reliability. PUC has strictly managed any increases to its OM&A budget in the test year. PUC will continue its on-going customer engagement initiatives while taking customer preferences into consideration in its business planning.

Unmetered Loads

PUC communicates with unmetered load customers, including Street Lighting customers, to assist them in understanding the regulatory context in which distributors operate and how it affects unmetered load customers. This communication takes place on an on-going basis and is not driven by the rate application process.

1.6 PERFORMANCE MEASUREMENT

1.6.1 Performance Evaluation

Under the renewed regulatory framework (RRFE), a distributor is expected to continuously improve its understanding of the needs and expectations of its customers and its delivery of services. To facilitate performance monitoring and benchmarking of distributors the OEB uses a scorecard approach.

In this Application, PUC has presented its performance for each of the Board's performance outcomes over the last five years, its current performance, and its projections for continuous improvements over the term of the Application. PUC has projected an increase to its efficiency percentage in the 2023 Test Year due to the inclusion of ICM Sub 16 and SSG Assets in rate base. PUC has taken this influx into consideration for its business plan projections for 2024-2027.

1.6.2 Scorecard

The Scorecard Approach, issued on March 5, 2014 details the scorecard measures approach which the Board expects to use in order to monitor and assess a distributor's effectiveness and improvement in achieving the four performance outcomes – Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance – and to facilitate distributor benchmarking. The Board has set industry targets for New Residential/Small Business Services Connected on Time, Scheduled Appointment Met on Time, Telephone Calls Answered on Time and Billing Accuracy. Other metrics such as Level of Compliance with O. Reg 22/04, number of public incidents, SAID and SAIFI have a trend indicator to identify how each LDC is trending in comparison to previous years. PUC reviews these metrics yearly to identify positive trending results and those that may require areas of improvement.

PUC has published its most recent scorecard for public viewing on its website at:

OEB Scorecard - Sault Ste. Marie PUC (ssmpuc.com)

Table 1-18 below provides PUC's 2016 to 2018 performance on its Scorecard metrics as reported to the OEB in the annual RRR filings. PUC's Scorecard, including its MD&A for 2021 is provided as Appendix E.

Table 1-18: PUC's 2016-2018 OEB Scorecard Results

Performance Outcomes	Performance Categories	Measures	2016	2017	2018	2019	2020	2021
CUSTOMER FOCUS	Service Quality	New Residential/Small Business Services Connected on Time (Target: 90%)	98.90%	96.67%	99.12%	100.00%	100.00%	97.60%
		Scheduled Appointments Met on Time (Target: 90%)	98.30%	97.62%	98.48%	98.65%	100.00%	99.92%
		Telephone Calls Answered on Time (Target: 65%)	81.30%	79.88%	77.70%	72.43%	68.88%	71.13%
	Customer Satisfaction	First Contact Resolution	99.58%	99.74%	99.80%	99.82%	99.76%	99.63%
		Billing Accuracy (Target: 98%)	99.97%	99.94%	99.97%	99.98%	99.96%	99.97%
		Customer Satisfaction Survey Results	80%	80%	80%	92%	92%	88%
OPERATIONAL EFFECTIVENESS	Safety	Level of Public Awareness	86%	85%	85%	85%	85%	85%
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C
		Number of General Public Incidents	-	-	1	1	2	-
		Rate per 10, 100, 1000 km of line	-	-	0.135	0.135	0.271	n/a
	System Reliability	Average Number of Hours Power to Customer is Interrupted	1.49	1.43	1.27	1.45	2.12	1.81
		Average Number of Times Power to Customer is Interrupted	1.41	1.21	1.28	1.55	1.74	1.32
	Asset Management	Distribution System Plan Implementation on Progress	In Progress	In Progress	100%	79%	90%	104%
	Cost Control	Efficiency Assessment (1 = most efficient 5 = least efficient)	4	4	4	4	3	3
		Total Cost ($) per Customer	$ 695	$ 673	$ 690	$ 697	$ 673	$ 696
		Total Cost ($) per Km of Line	$ 31,314	$ 30,541	$ 31,338	$ 31,775	$ 30,794	$ 31,915
PUBLIC POLICY RESPONSIVENESS	Energy Savings	Net Cumulative Energy Savings (Percent of Target Achieved)	52.97%	92.47%	104.84%	111.46%	n/a	n/a
	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed on Time	n/a	100%	n/a	100%	n/a	n/a
		New Micro-Embedded Generation Facilities Connected on Time (Target: 90%)	100%	n/a	n/a	n/a	n/a	n/a
FINANCIAL PERFORMANCE	Financial Ratios	Liquidity: Current Ratio	1.52	1.62	1.33	0.94	0.99	0.8
		Leverage: Total Debt to Equity Ratio	2.34	2.04	2.02	2.03	2.07	2.09
		Profitability: Regulatory Return on Equity - Deemed	8.98%	8.98%	9.00%	9.00%	9.00%	9.00%
		Profitability: Regulatory Return on Equity - Achieved	0.98%	1.78%	4.25%	8.87%	8.75%	7.60%

1.6.3 Customer Focus

Service Quality

Table 1-19: Scorecard Performance Category - Service Quality

Performance Year	New Residential/Small Business Services Connected on Time (Target: 90%)	Scheduled Appointments Met on Time (Target: 90%)	Telephone Calls Answered on Time (Target: 65%)
2021	97.60%	99.92%	71.13%
2020	100.00%	100.00%	68.88%
2019	100.00%	98.65%	72.43%
2018	99.12%	98.48%	77.70%
2017	96.67%	97.62%	79.88%

New Residential/Small Business Connected on Time

As shown in Table 1-19 above, over the last 5 years, PUC has consistently exceeded the OEB mandated target of at least 90% in connecting new residential or small business customers on time. In the last 3 years (2018-2021), PUC has maintained an exceptional level of connections on time. During that time PUC connected 176, 193 and 244 eligible low-voltage residential and small business customers on time. PUC is consistently able to achieve high levels of compliance in this area due to our existing workflow processes. Our commitment to customer care is demonstrated through staff education, customer engagement activities and the investigation of any opportunity for improvement.

PUC's target for this metric in 2023 is 90%.

Scheduled Appointments Met On Time

As a result of our emphasis on customer satisfaction, over the last 5 years PUC has consistently exceeded the OEB mandated target of at least 90% in scheduled appointments met on time. PUC has scheduled 1,020, 1,119 and 1,251 appointments in 2019, 2020 and 2021 respectively in relation to meter installs and removals, service disconnects and reconnects, and meter locates etc. and has yielded an average on time completion percentage within a 4-hour window of 98.93% over the last 5 years.

PUC's target for this metric in 2023 is 90%.

Telephone Calls Answered on Time

Between 2017 and 2021, PUC has experienced an average of 46,545 calls from customers per year, which equals approximately 186 calls per working day. PUC has seen a slight downward trend in telephone calls answered on time. In 2020, the COVID 19 pandemic hit creating a shift to a work-from-home environment. PUC experienced increased talk times due to the COVID-19 pandemic and was still able to exceed the OEB's mandated target. Additionally, PUC has been looking to other forms of communication via MyPUC App and Customer Chat to help with call volumes. In spite of this large call volume, PUC's Customer Experience department has answered these calls within 30 seconds or less 74% of the time on average over the last 5 years. This result significantly exceeds the OEB mandated 65% target for timely call response.

PUC's target for this metric in 2023 is 65%.

Customer Satisfaction

Table 1-20: Scorecard Performance Category - Customer Satisfaction

Performance Year	Billing Accuracy (Target: 98%)	First Contact Resolution	Customer Satisfaction Survey Results
2021	99.97%	99.63%	88%
2020	99.96%	99.76%	92%
2019	99.98%	99.82%	92%
2018	99.97%	99.80%	80%
2017	99.94%	99.74%	80%

First Contact Resolution

PUC's First Contact Resolution ("FCR") was measured by tracking the number of electric related calls which were escalated to a Senior Customer Experience Representative or Supervisor/Manager. This was accomplished by creating two specific call types in PUC's Customer Information System (CIS) which could then be tracked to provide the number of customer concerns that were escalated. To establish the number of calls which were handled without escalation, the total number of calls escalated to a higher level were subtracted from the total number of calls received. However, it should be noted that FCR can be measured in a variety of ways and further regulatory guidance is necessary in order to achieve meaningful comparable information across electricity distributors. As shown in Table 1-20 above thus far, PUC has maintained a FCR percentage above the distributor target of 99%, averaging 99.75% since 2017.

PUC's target for this metric in 2023 is 99%.

Billing Accuracy

PUC issues approximately 366,565 bills annually and has achieved an average accuracy percentage of 99.97% over the 3-year period of 2019 to 2021. This score compares favourably to the prescribed OEB target of 98%. PUC continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

PUC's target for this metric in 2023 is 98%.

Customer Satisfaction Survey

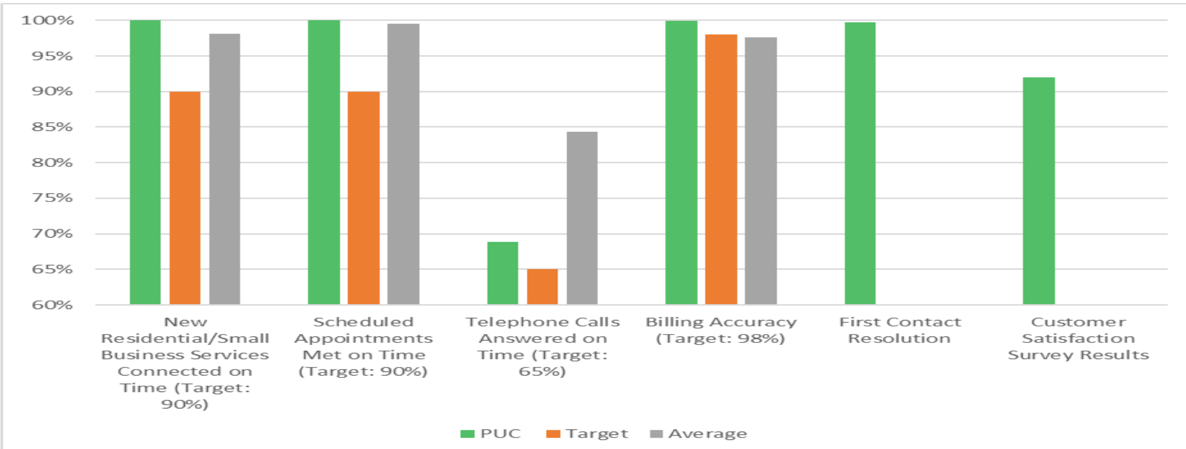
PUC engaged the UtilityPULSE Division of Simul Corporation to conduct PUC's 2019 and 2021 customer satisfaction surveys. The survey is attached as Appendix F. The UtilityPULSE Electric Utility Survey is in its 23rd year of annual surveys and is used by a significant number of Ontario distributors. In 2019, the final report on our customer satisfaction survey was received in March 2019, and PUC received a customer satisfaction score of 92% (post survey result) which is above the Ontario benchmark survey that had a grade of "B". For 2021, the final report on PUC's customer satisfaction survey was received in March 2022, and PUC received an A customer satisfaction score of 88% (post survey result). Overall PUC has seen significant improvement from its 2017 survey results of 85%. The survey asked customers questions on a broad range of topics, including overall satisfaction with reliability, customer service, outages, billing and corporate image. These customer satisfaction surveys are an important element in our overall customer engagement strategy providing further insight towards planning and supporting customer service improvement at all levels within PUC.

PUC's target for this metric in 2019 is "A-" or 85%.

Figure 1-20 below compares PUC's 2021 Service Quality and Customer Satisfaction results to the provincial target and the average for all LDCs in the province. Currently there are no provincial targets for FCR and Customer Satisfaction Survey.

As indicated, PUC met all provincial targets in 2021. For the telephone call answered metric, although PUC exceeds the provincial target, it is below the provincial averages of 84.3%. As noted above PUC is exploring options to reduce telephone traffic to improve the calls answered metric and provide a more efficient method for customers to interactive with the LDC. For Customer Satisfaction, PUC has improved significantly from its previous survey as a result of the activities outlined in Appendix K.

Figure 1-20: Provincial Comparison - Customer Focus – Service Quality and Customer Satisfaction



1.6.4 Operational Effectiveness

Safety

Table 1-21: Scorecard Performance Category – Safety

Performance Year	Level of Public Awareness	Level of Compliance with Ontario Regulation 22/04 (Target: substantially	Number of General Public Incidents	Rate per 10, 100, 1000 km of line
2021	85%	C	0	0
2020	85%	C	2	0.271
2019	85%	C	1	0.135
2018	85%	C	1	0.135
2017	85%	C	0	0

The public safety measure was introduced by the OEB in 2015 and focuses on Component A - the safety of the distribution system from a customer's point of view. The Electrical Safety Authority ("ESA") provides an assessment as it pertains to Component B – Compliance with

Ontario Regulation 22/04 Electrical Distribution Safety ("O.Reg. 22/4" or "the Regulation") and Component C – Serious Electrical Incident Index (see Table 1-21 above).

Component A - Public Safety Awareness

The Public Awareness of Electrical Safety measure is determined by public survey. The purpose of the survey is to monitor the effort and impact LDC's are having on improving public electrical safety for the Distribution Network. This public safety survey is intended to be conducted every two (2) years. The questions on the survey are standardized across the province.

PUC's third safety awareness survey was conducted in 2020 and resulted in a score of 85%. This was consistent with the previous Safety survey.

PUC continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness within PUC's service area. Through participation with the Association of Electrical Utility Safety Professionals ("AEUSP"), PUC has contributed to the production of a series of electricity safety videos for television broadcast in various Ontario markets including its own service area.

PUC promotes electrical safety awareness in a variety of other forms. The importance of awareness of electrical hazards is conveyed throughout the community via safety related communications in newspapers, on the radio and at public events. Detailed hazard awareness presentations are made available to external contractors and joint use parties. In the broader community, public safety presentations are provided to elementary school students.

PUC's target for this category is 85% in 2023.

Component B - Regulatory Compliance with Ontario Reg. 22/04

Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the Regulation requires the approval of equipment, plans and specifications and the inspection of construction before new assets are put into service. Component B includes an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. ESA evaluates these elements in order to determine the status of compliance.

For the past 10 years, PUC was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This success was achieved through PUC's strong commitment to safety and adherence to regulatory requirements, company policies and procedures.

PUC's target for this metric in 2023 is to have zero (0) safety non-compliance.

Component C – Serious Electrical Incident Index

Section 12 of Ontario Regulation 22/04 specifies the requirement to report to ESA any serious electrical incident of which they become aware within 48 hours after the occurrence. As assessed by ESA, in the 2021 reporting period, there were zero reportable serious electrical incidents.

PUC remains strongly committed to both the safety of staff and the general public. PUC regularly provides its customers with electrical safety information via its website, social media, and bill inserts. Additionally, PUC continues to make significant maintenance and capital infrastructure investments to enhance system safety and reliability.

PUC's target for this metric in 2023 is to have zero (0) serious electrical incidents reported.

System Reliability

Table 1-22: Scorecard Performance Category – System Reliability

Performance Year	Average Number of Hours Power to Customer is Interrupted (SAIDI)	Average Number of Times Power to Customer is Interrupted (SAIFI)
2021	1.81	1.32
2020	2.12	3.14
2019	1.7	1.68
2018	1.28	1.27
2017	1.21	1.43

Table 1-22 above displays the system reliability data from 2017-2021. A key change for 2016, as required by the OEB, is the revised reporting of reliability data with respect to Major Events. Specifically, the change serves to adjust the reliability data to remove the impact of Major Events. Additionally, distributors are required to report criteria to monitor the distributor's performance related to the Major Event. The 2017-2021 Scorecard's system reliability data, excludes both Loss of Supply and Major Events. The adjusted reliability measures capture interruptions caused by circumstances within the distributor's control and are published in the 2021 scorecard. A "Major Event" is defined as an event that is beyond the control of the distributor and is unforeseeable, unpredictable, unpreventable, or unavoidable. Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, take significantly longer than usual to repair, and affect a substantial number of customers. PUC calculates major event day scope using the IEEE Standard 1366-2003, "IEEE Guide for Electric Power Distribution Reliability Indices".

SAIDI and SAIFI

The average duration of outages is often due to the severity of weather events – System Average Interruption Duration Index ("SAIDI") and the number of times power to a customer is interrupted is often due to accidents, storms, lightning, high wind and defective equipment – System Average Interruption Frequency Index ("SAIFI").

Approximately 40% of all of PUC's outages can be attributed to defective equipment. PUC also experienced large number of outages caused by adverse weather which typically included high winds (resulting in tree contact), snowstorms and rainstorms.

PUC programs in place to address reliability include:

- Use of high-quality engineering design standards;
- Proactive upgrading of equipment (switches, restricted wire);
- Smart meter data to quickly identify outages;
- Preventative maintenance such as infrared scanning and pole testing; and
- Diligent tree-trimming program.

<u>System Average Number of Hours that Power to a Customer is Interrupted (SAIDI)</u>

The System Average Interruption Duration Index ("SAIDI") of 1.81 in 2021 was above the distributor target of 1.38. In recent years PUC has seen a slight increase in its SAIDI as seen in Table 1-23 below. There are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management. PUC is also in the process of completing its SSG project, which once fully commissioned, is expected to help improve its reliability results. Since 10 substations and multiple circuits will be turned off at different stages of the construction project, it is anticipated that potential planned outages will impact more customers or may take longer to remediate, possibly resulting in a short-term reliability performance metric decline for the end of 2022 and the first quarter of 2023.

Still in 2023, PUC's target for SAIDI is 1.62.

Table 1-23: Historical SAIDI Results

Performance Year	Average Number of Hours Power to Customer is Interrupted (SAIDI)
2021	1.81
2020	2.12
2019	1.45
2018	1.27
2017	1.43

System Average Interruption Frequency Index (SAIFI)

The System Average Interruption Frequency Index ("SAIFI") of 1.32 in 2021 was just below the target of 1.33. Consistent with SAIDI, there are ongoing efforts to improve reliability including replacing aging infrastructure and improving vegetation management. Table 1-24 shows the historical SAIFI results.

Table 1-24: Historical SAIFI Results

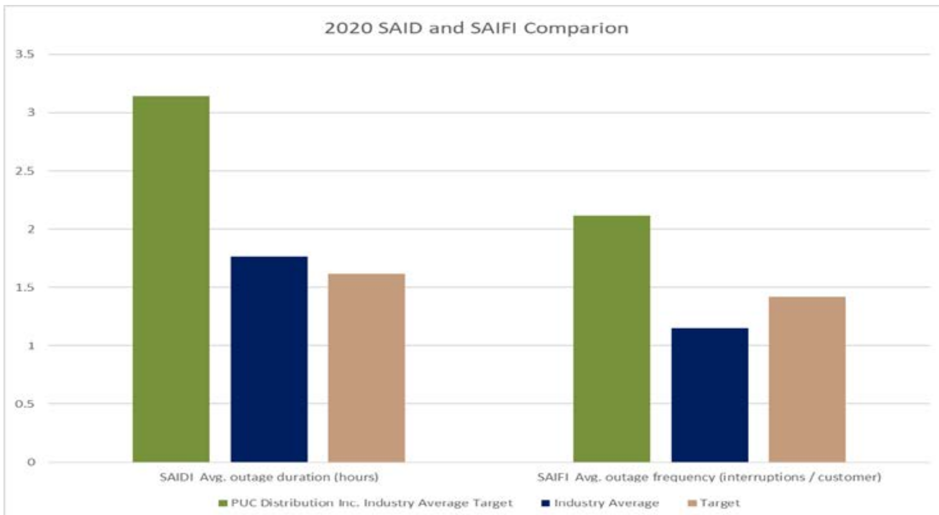
Performance Year	Average Number of Times Power to Customer is Interrupted (SAIFI)
2021	1.32
2020	1.74
2019	1.55
2018	1.28
2017	1.21

PUC's target for SAIFI in 2023 is 1.42.

Figure 1-21 below compares PUC's 2020 Operational Effectiveness in the system reliability area to the industry average and its scorecard target for 2023.

As indicated, PUC 's SAIDI and SAIFI has been higher in recent years. Equipment failures have been the predominant cause of outages in the last several years. To improve reliability, all of the investments in the "System Renewal" category of fixed assets are aimed at replacing assets in very poor or poor condition with priority given to renewal of those assets in highest risk of failure with most serious consequences.

Figure 1-21: Reliability & Scorecard Target



Asset Management

Table 1-25: Scorecard Performance Category – Asset Management

Performance Year	Distribution System Plan Implementation on Progress
2021	104%
2020	90%
2019	79%
2018	100%
2017	In Progress

Table 1-25 above displays the Asset Management progress from 2017 to 2021.

Distribution System Plan (DSP) Implementation Progress

Consistent with industry best practices, PUC invests in its distribution system to ensure the safe and reliable delivery of electricity; and upgrades or replaces equipment to be able to serve customers on a continuous basis. The DSP, which covers the five-year period 2018-2022, was filed with the OEB as part of the 2018 COS Application. Prior to 2018, the OEB scorecard indicated 'In Progress' in the Performance Category of Asset Management to reflect this activity.

For years 2018 and onwards, PUC has established a metric which expresses performance by comparing the ratio of cumulative actual capital expenditures to-date against cumulative planned capital expenditures to-date for the period starting January 1, 2018 and ending on December 31 of each scorecard year. The ratio is then expressed as a percentage. The metric measures the LDCs overall performance completing capital work and includes all elements identified in the DSP inclusive of System Access, System Renewal, System Service and General Plant. The metric will include the cumulative expenditures for all previous years within the 5-year rate application period 2018-2022. So, for example the 2021 scorecard will show a cumulative percent expenditure for the first three years of the 2018-2022 rate application period. In effect, the metric gives a snapshot at the end of each year as to how closely the LDC is tracking to their plans in achieving the overall 5-year plan. PUC intends to file a new DSP covering the 2023 to 2027 period as part of its 2023 COS application.

The calculated value for this performance metric for 2021 is 104%. The year-over-year increase in the score reported for this metric (90% in 2020 versus 79% in 2019) - was attributable the planned rescheduling of a distribution station rebuild project (Sub-16) from 2019 to 2020/2021.

PUC has prepared a 2023-2027 DSP for its 2023 COS Application. As an ongoing target to meet the requirements of this DSP, PUC will continue to revisit and revise its capital spending based on system needs, cash flow forecasting, and the overall DSP plan itself.

Cost Control

Table 1-26 below summarizes PUC's Cost Control results from 2017 to 2021 which are explained further below.

Table 1-26: Scorecard Performance Category – Cost Control

Performance Year	Efficiency Assessment (1 = most efficient 5 = least efficient)	Total Cost ($) per Customer	Total Cost ($) per Km of Line
2021	3	696	31,915
2020	3	673	30,791
2019	3	697	31,775
2018	4	690	31,338
2017	4	673	30,541

Efficiency Assessment

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC ("PEG") on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs. Table 1-27 below summarizes the distribution of all distributors across the 5 groupings for 2021.

Table 1-27: Distribution of Distributors

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	13
2	Actual costs are 10% to 25% below predicted costs	More Efficient	15
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	23
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	4
5	Actual costs are 25% or more above predicted costs	Least Efficient	2

Since PUC's last rebasing application in 2018, it has been working towards improvement in its efficiency performance. Table 1-28 below shows PUC's actual vs predicted costs since 2017 and its resulting Group Ranking. In 2019, PUC moved from group 4 to group 3 and has remained there. PUC has completed a prediction of 2022 and 2023 based on its OM&A and Capital Budget for those respective years.

Table 1-28: Actual vs. Predicted Costs

Year	Actual Costs	Predicted Costs	Cost Efficiency Assessment	3 Year Average	Stretch Factor Assisngment Group
2023 Projection	$32,892,271	$28,463,204	14.5%	5.6%	3
2022 Projection	$25,198,794	$25,039,845	0.6%	1.2%	3
2021 Actual	$23,585,229	$23,172,578	1.8%	2.8%	3
2020 Actual	$22,723,503	$22,474,823	1.1%	4.9%	3
2019 Actual	$23,450,122	$22,196,232	5.5%	8.3%	3
2018 Actual	$23,190,013	$21,371,771	8.2%	11.1%	4
2017 Actual	$22,600,176	$20,196,516	11.2%	13.8%	4

In 2023, PUC is projecting higher actual costs due to the reporting required for Sub-16 ICM and SSG ICM. Both ICM's are reported as capital expenditure in 2023 as per the RRR filing requirements and therefore inflate PUC's actual costs for that year. PUC expects its actual costs to stabilize in 2024, thus bringing back down its efficiency percentage. Additionally, it should be noted that PUC has additional costs and savings that are not accounted for in the PEG model.

Included in PUC's operating, maintenance and administrative expenses is a charge from PUC Services Inc. that is based on depreciating and financing of vehicles, tools, computer equipment, office equipment etc. that are utilized to provide utility services to PUC. For utilities that own the vehicles and equipment to service their customers, these expenses are included in depreciation and financing (i.e. interest) costs. As the total costs would be the same, removing the depreciation and financing costs from PUC's operating costs would better align costs comparisons in the PEG model with other utilities.

In 2023, VVO savings from SSG, are not accounted for in the PEG model methodology due to the unique, innovative nature of the project. Rather than SSG improving PUC's Financial Performance, it improves the financial situation for its customers, saving them an estimated 2.70% on their cost of power. There are 3 inputs into the PEG Benchmarking model ("PEG Model") that are unique to PUC and should be considered in the assessment of PUC's PEG Model results. Table 1-29 below shows adjustments for capital additions, kWh delivered and cost of power savings to customers.

Table 1-29: PEG Benchmarking Model Adjustments

Input	Default	Adjustment	Revised
Capital Additions	$45,437,837	($7,355,438)	$38,082,399
Deliveries	578,722,961	16,059,116	594,782,077
Cost of Power Savings to customer 2.70%	$0	$1,950,831	$1,950,831

The first adjustment is to account for the amount of NRCan funding PUC is receiving for the SSG project. In the PEG Model, total gross capital additions are used as the basis of this input. However, if we take into consideration the amount of NRCan funding PUC will receive, it significantly reduces the calculation of actual costs.

The second adjustment is for the input relating to kWh deliveries in a given year. PUC is investing this large amount into its infrastructure to benefit customers which will reduce their consumption and provide energy savings. This reduction in consumption predicts that PUC should have lower costs. While this is true in years beyond 2023, it is not something PUC anticipates will be immediately experienced in 2023. Therefore, an adjustment of 2.70% in consumption is added back for this input within the PEG model.

The third adjustment is for the total cost of power savings PUC customers will receive. As presented in Table 5.327 of the DSP, the total power savings is $1,950,000. If this adjustment is reflected in the actual costs, it further reduces PUC's actual costs when compared to predicted costs.

After taking these adjustments into consideration, the revised efficiency percentage is 5.80% as outlined in Table 1-30 below. As such, PUC's target is to remain in Group 3 in 2023.

Table 1-30: Revised Efficiency Percentage

Year	Actual Costs	Predicted Costs	Cost Efficiency Assessment	3 Year Average	Stretch Factor Assisngment Group
2023 Projection	$30,149,181	$28,463,204	5.8%	2.7%	3

Total Cost per Customer

Total cost per customer is calculated as the sum of PUC's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e., under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC serves. PUC's cost performance results, from 2017 to 2021, have increased from $673 to $696 per customer. Overall, the company's total cost per customer has increased on average by 3.42% per annum over the period 2017 through 2021. For the period of 2017 to 2021, the total cost per customer on average has increased by approximately 0.84% per year. PUC will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2021 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC's capital spending plans.

As with PUC's efficiency ranking above, this calculation uses PUC's actual costs in calculating the total cost per customer. In 2023, PUC is projecting an outlier year in actual costs due to the reporting of Sub-16 and SSG as capital additions to rate base. This will inflate PUC's total cost per customer to $967 for 2023 and should return to more normalized levels in 2024. The table below shows PUC's historical results and projections for 2022 and 2023.

Table 1-31: Actual Total Cost Per Customer

Year	Total Cost per Customer
2023 Projection	$965
2022 Projection	$742
2021 Actual	$696
2020 Actual	$673
2019 Actual	$697
2018 Actual	$690
2017 Actual	$673

After taking the adjustments outlined in Table 1-31 above, the total cost per customer is $885. Furthermore, if you remove Sub-16 and SSG spending it drops the projection to $823.

Table 1-32: 2023 Projection Total Cost Per Customer

Year	Total Cost per Customer
2023 Projection	$885
2023 Projection (SSG Sub 16 Removed	$823

PUC's target is a total cost per customer of $823 after excluding costs for Sub-16, SSG, and non-operational costs discussed above.

Total Cost Per Km of Line

LDC costs can differ significantly based on service territory size, physical attributes of the service territory, rural vs. urban customer mix, local weather conditions, etc. PUC is one member of the group of provincial LDCs that has less than 50 customers per kilometer of line.

PUC has used data from the 2021 PEG Benchmarking Spreadsheet to compare costs against LDCs with less than 50 customers per kilometer of line.

As discussed above, included in PUC's OM&A expenses is a charge from PUC Services that is based on depreciating and financing of vehicles, tools, computer equipment, office equipment etc. that is utilized to provide utility services to PUC. For utilities that own the vehicles and equipment to service their customers, these expenses are included in depreciation and financing costs. As the total costs would be the same, removing the depreciation and financing costs from PUC's costs would better align cost comparisons. The following comparison utilizes the data from the '2021 PEG Benchmarking Spreadsheet. To better align with similar utilities, PUC compared to utilities that have less than 50 customers per kilometer of line. As outlined in Table 1-33 below, when analysing the total cost per customer for the 2021 year, PUC's cost per customer is $696. The average for all utilities in the province with less than 50 customers per kilometer of line is $711 per customer.

Table 1-33: 2021 Total Cost per Customer Comparison (<50 Customers per Km of Line)

Distributor	Year	Stretch Fact	Cohort Numb	Efficiency Assessment	Cost per Customer	Cost per km of Line	Cost	Customers	km	Customer/Km of Line
Algoma Power Inc.	2021	0.60	5.00	63.3%	2,338	13,025	28,589,748	12,227	2,195	6
Toronto Hydro-Electric System Limited	2021	0.60	5.00	53.0%	1,189	32,110	933,973,904	785,667	29,087	27
Hydro One Networks Inc.	2021	0.45	4.00	17.5%	1,033	11,940	1,487,153,374	1,440,315	124,556	12
Atikokan Hydro Inc.	2021	0.30	3.00	2.8%	1,024	18,024	1,658,233	1,619	92	18
Canadian Niagara Power Inc.	2021	0.45	4.00	12.8%	905	17,810	27,177,914	30,042	1,526	20
Innpower Corporation	2021	0.30	3.00	-5.8%	897	12,072	17,674,127	19,703	1,464	13
Wellington North Power Inc.	2021	0.30	3.00	1.9%	831	15,101	3,276,916	3,942	217	18
Waterloo North Hydro Inc.	2021	0.30	3.00	5.2%	826	29,276	48,509,585	58,747	1,657	35
Sioux Lookout Hydro Inc.	2021	0.00	1.00	-26.6%	818	3,335	2,374,552	2,904	712	4
Halton Hills Hydro Inc.	2021	0.00	1.00	-33.3%	813	10,928	18,479,532	22,738	1,691	13
Chapleau Public Utilities Corporation	2021	0.45	4.00	16.1%	781	17,697	955,648	1,224	54	23
Niagara-on-the-Lake Hydro Inc.	2021	0.15	2.00	-11.8%	768	23,000	7,474,877	9,731	325	30
Niagara Peninsula Energy Inc.	2021	0.30	3.00	-3.2%	750	9,522	43,324,122	57,769	4,550	13
North Bay Hydro Distribution Limited	2021	0.30	3.00	2.2%	729	30,857	17,711,815	24,280	574	42
Lakeland Power Distribution Ltd.	2021	0.15	2.00	-16.9%	715	27,856	10,139,728	14,180	364	39
Bluewater Power Distribution Corporation	2021	0.30	3.00	-3.9%	714	21,932	26,427,868	37,016	1,205	31
Espanola Regional Hydro Distribution Corporation	2021	0.15	2.00	-24.0%	713	23,638	2,387,478	3,348	101	33
Oakville Hydro Electricity Distribution Inc.	2021	0.30	3.00	-3.3%	710	26,506	53,303,374	75,110	2,011	37
Northern Ontario Wires Inc.	2021	0.00	1.00	-42.0%	704	11,287	4,176,217	5,934	370	16
PUC Distribution Inc.	2021	0.30	3.00	2.8%	696	31,915	23,585,229	33,865	739	46
Alectra Utilities Corporation	2021	0.30	3.00	-3.7%	691	14,252	739,257,355	1,069,684	51,872	21
Milton Hydro Distribution Inc.	2021	0.15	2.00	-23.1%	683	10,221	28,760,591	42,082	2,814	15
Burlington Hydro Inc.	2021	0.15	2.00	-12.1%	683	30,949	46,918,216	68,742	1,516	45
Greater Sudbury Hydro Inc.	2021	0.30	3.00	3.2%	679	31,877	32,483,130	47,865	1,019	47
Energy+ Inc.	2021	0.15	2.00	-14.1%	677	29,990	46,183,891	68,201	1,540	44
EnWin Utilities Ltd.	2021	0.15	2.00	-15.9%	675	12,989	61,098,531	90,556	4,704	19
Fort Frances Power Corporation	2021	0.30	3.00	-9.8%	669	30,891	2,502,140	3,739	81	46
Centre Wellington Hydro Ltd.	2021	0.30	3.00	-9.7%	660	30,457	4,873,175	7,385	160	46
Elexicon Energy Inc.	2021	0.30	3.00	-2.7%	652	28,531	111,811,625	171,564	3,919	44
Synergy North Corporation	2021	0.30	3.00	2.0%	651	29,384	37,052,809	56,945	1,261	45
Newmarket-Tay Power Distribution Ltd.	2021	0.15	2.00	-14.4%	649	28,216	28,892,924	44,519	1,024	43
Westario Power Inc.	2021	0.30	3.00	-9.7%	610	25,340	14,773,458	24,201	583	42
Grimsby Power Incorporated	2021	0.00	1.00	-34.9%	602	10,315	7,148,156	11,870	693	17
EPCOR Electricity Distribution Ontario Inc.	2021	0.15	2.00	-10.1%	584	28,487	10,796,649	18,485	379	49
Hearst Power Distribution Company Limited	2021	0.00	1.00	-30.3%	570	15,946	1,546,725	2,715	97	28
Essex Powerlines Corporation	2021	0.15	2.00	-24.8%	564	10,789	17,423,626	30,908	1,615	19
Entegrus Powerlines Inc.	2021	0.00	1.00	-25.0%	558	10,670	34,303,560	61,508	3,215	19
Ottawa River Power Corporation	2021	0.15	2.00	-24.0%	521	11,805	6,020,446	11,549	510	23
Lakefront Utilities Inc.	2021	0.00	1.00	-26.2%	518	24,743	5,567,079	10,756	225	48
Welland Hydro-Electric System Corp.	2021	0.00	1.00	-29.5%	494	24,455	12,154,000	24,627	497	50
Wasaga Distribution Inc.	2021	0.00	1.00	-48.7%	427	21,189	6,187,118	14,488	292	50

This measure uses the same total cost that is used in the cost per customer calculation above. The total cost is divided by the kilometers of line that the company operates to serve its customers. PUC's cost performance results, from 2017 to 2021, have increased from $30,541 to $31,915 per km of line.

PUC continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per km of line has increased 4.50% since 2017 with the increase in capital and operating costs. For the period of 2017 to 2021, the total cost per km of line has increased by approximately 0.90% per year. A summary of the results is provided in table 1-34.

Table 1-34: Total Cost per Km of Line

Year	Total cost per Km of Line (revised)	Total cost per Km of Line
2023 Projection	$38,018	$44,569
2022 Projection	$34,145	$34,145
2021 Actual	$31,915	$31,915
2020 Actual	$30,791	$30,791
2019 Actual	$31,775	$31,775
2018 Actual	$31,338	$31,338
2017 Actual	$30,541	$30,541

PUC is projecting a spike in 2023 for the same reasons mentioned above. This spike is a one-time outlier. After adjusting for the increased costs due to Sub-16, SSG, and non operating costs discussed above, PUC is projecting a target of $38,018 in 2023.

1.6.5 Public Policy Responsiveness

Conservation and Demand Management

In 2019, conservation programs were centralized through the IESO by the government. Utilities no longer receive incentive payments for achieving targets.

Renewable Generation Connection Impact Assessments Completed on Time

Electricity distributors are required to conduct Connection Impact Assessments ("CIAs") within 60 days of receiving authorization for their project from the ESA. In 2021, PUC received no renewable generation CIA applications.

PUC's target for this metric in 2023 is to complete all assessments within the prescribed timelines.

New Micro Embedded Generation Facilities Connected on Time

Distributors are required to connect micro-embedded generation facilities within five business days of receiving all required authorizations, signed agreements and connection fees for a micro-embedded generation facility. PUC connected three net-metered facilities in 2021 on time, in which the application and offer to connect for one were completed at the end of 2020 and two were completed fully in 2021.

PUC's target for this metric in 2023 is to connect micro-embedded generation facilities within 5 business days of all service connection requirements being met.

1.6.6 Financial Performance

Financial Ratios

Table 1-35 below details the financial ratios from 2017 to 2021.

Table 1-35: Scorecard Performance Category – Financial Ratios

Performance Year	Liquidity: Current Ratio	Leverage: Total Debt to Equity Ratio	Profitability: Regulatory Return on Equity - Deemed	Profitability: Regulatory Return on Equity - Achieved
2021	0.80	2.10	9.00%	7.60%
2020	0.99	2.07	9.00%	8.75%
2019	0.94	2.03	9.00%	8.87%
2018	1.33	2.02	9.00%	4.25%
2017	1.62	2.04	8.98%	1.78%

In the Board's Scorecard Report, Board staff recommended three measures to assess a distributor's financial viability: current ratio, total debt to equity ratio, and achieved regulated return on equity.

Liquidity: Current Ratio (Current Assets/Current Liabilities)

As an indicator of financial health, a current ratio that is greater than 1 is considered good as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations. Since 2017, PUC has seen a downward trend, however, this is misleading as it is being skewed by certain affiliate transactions that are treated as current versus long-term for financial statement purposes. Specifically, the current ratio is affected by how PUC funds its capital expenditures and the timing of third-party financing arrangements. Going forward PUC will look at obtaining financing prior to its year ends which will shift more of the current liability to long-term debt and improve the presentation of its current ratio.

PUC's target for this metric in 2023 is a current ratio above 1.

Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio

The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt-to-equity ratio of 1.5 (60/40). A debt-to-equity ratio of more than 1.5 indicates that a distributor is more highly levered than the deemed capital structure. A high debt to equity ratio may indicate that an electricity distributor may have difficulty generating sufficient cash flows to make its debt payments. A debt-to-equity ratio of less than 1.5 indicates that the distributor is less levered than the deemed capital structure. A low debt to equity ratio may indicate that an electricity distributor is not taking advantage of the increased profits that financial leverage may bring. Historically, PUC's debt to equity has remained at a level close to 2:1. PUC will be undergoing additional financing for the completion of the SSG project in 2022. This will increase debt to equity in 2023 to approximately 2.36:1. PUC's long-range plan is to push the debt to equity back towards the deemed 60/40 level.

PUC's target for this metric in 2023 is to reduce the debt to equity to 60%/40%.

Profitability: Regulatory Return on Equity – Deemed (included in rates)

PUC's current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity ("ROE") of 9.00%. The OEB allows a distributor to earn within +/- 3 percentage points of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and costs structure by the OEB.

<u>Profitability: Regulatory Return on Equity – Achieved</u>

PUC's return on equity in 2021 is 7.60% which is within the +/- 3 percentage points of the expected ROE. Return on Equity has stabilized just below the deemed ROE embedded in existing rates of 9.00% in recent years with a slight dip in 2021 due to the realization of COVID related expenses. PUC will be rebasing its rates in 2023 with rates effective May 1, 2023. As of August 2022, the deemed Return on Equity as part of the OEB's Cost of Capital Parameters is 8.66%. PUC expects the Cost of Capital Parameters to undergo an increase due to the rising cost of inflation. Since PUC currently has more debt than the OEB deemed structure of 60/40 debt to equity, PUC is projecting its ROE to be under 7.00% in 2023. As PUC's rate base increases through to 2027 and the amount of debt moves closer to 60/40 level, ROE will improve by 2027.

In 2023, PUC is projecting an ROE of 6.80% based on current OEB Cost of Capital Parameters.

1.6.7 Activity and Program Based Benchmarking

On February 25, 2022, the OEB announced changes to the Activity and Program-Based Benchmarking (APB) framework in line with its commitment to drive utility performance and support efficiencies in the regulatory process. Utilities were required to gather 3 years of historical data (2018, 2019 and 2020) to be used in unit cost metric calculations which compares all LDC's amongst each other. PUC has been in communication with the OEB to revise its data reported for the APB metrics. On May 4, 2022, the OEB published a new APB report with unit cost results updated by the OEB and econometric results updated by the project consultant, Pacific Economics Group Research LLC. PUC has been in communication with the OEB to revise its data reported for the APB metrics which have now been rectified. The following analysis is based on the updates provided. Table 1 -36 shows the revised inputs used in the analysis below. Given the APB initiative is a newer requirement, PUC is currently in the process of how to address future planning as a result of these outcomes.

Table 1-36: Revised APB Results

(2) Please provide the quantity of equipment installed that corresponds to the capital additions above for the two asset types (per USoAs) for the fiscal year in the table below

Fiscal Year	Account 1830, Poles Towers and Fixtures	Account 1850, Line Transformers	Account 1860 Meters	Comments
2021	188	118	50	
2020	165	80	215	
2019	169	101	413	
2018	262	113	782	

Notes: The installed poles and towers comprise all types of poles (e.g., wood, concrete and steel) placed in service in the year

(3) Please provide the total quantity of equipment that existed as installed or in-service within the distributors' system at the end of the fiscal year for each of the asset types (per USoA) listed below

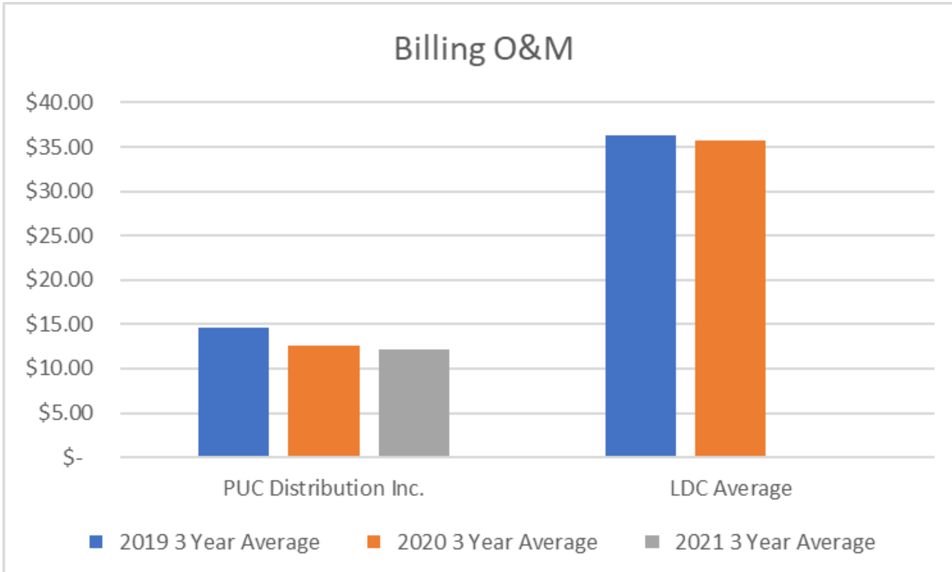
Fiscal Year	Total Number of Stations	Total Number of Station Transformers (Account	Total MVA of Station Transformers (Account	Total Number of Poles and Towers (Account 1830)	Total Number of Line Transformer (Account	Comments
2021	14	28	260	18186	6225	poles and towers includes both PUC and third party poles.
2020	14	28	260	18125	6215	poles and towers includes both PUC and third party poles.
2019	14	28	260	18125	6208	
2018	14	28	260	18125	6188	

Notes: All of these data points for (3) are the same type as requested in Q5 of the November 2020 APB questionnaire (https://www.oeb.ca/sites/default/files/OEB-Ltr-APB-Info-Request-20201112.pdf)

Billing O&M

PUC's 3-year average for billing cost O&M is $12.57/customer for 2018-2020. In 2021 the 3-year average is reduced to $12.13. PUC ranks among the lowest in billing cost O&M as presented in the graph below. Given PUC's excellent results, no immediate remedial action is required. The following graph provides PUC's results.

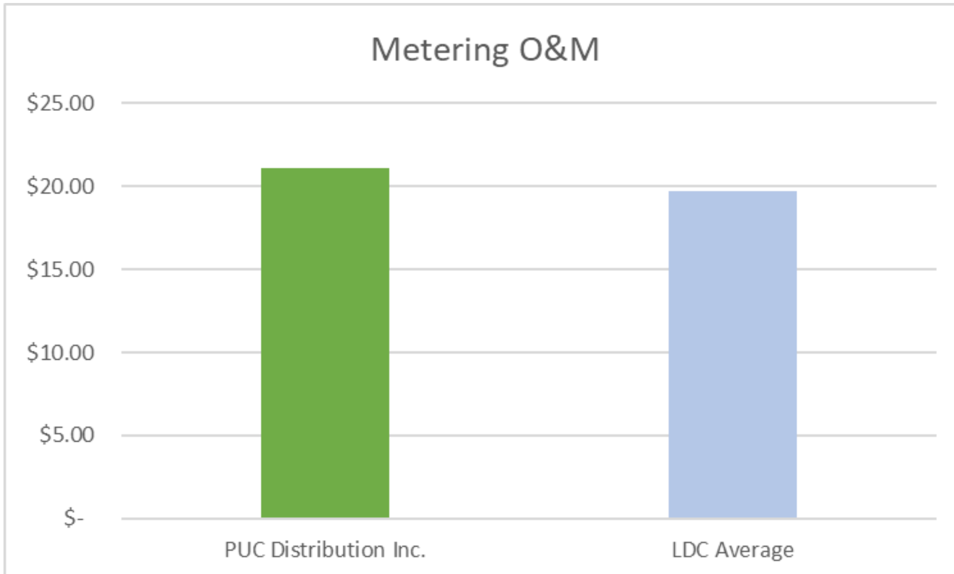
Figure 1- 22: Billing O&M



Metering O&M

PUC's 3-year average for metering O&M is $21.12 from 2018-2020. That number improves to $20.23 for the 3-year period from 2019-2021. PUC is slightly above the average of all LDC's of $19.68. PUC is in the process of investigating why it has a higher unit cost for metering O&M including a review of accounts 5065, 5175, 5310. PUC's metering capital expenditures is one of the lowest among LDC's suggesting that PUC expenses more metering costs as OM&A as compared to capital. This will be reviewed in further detail for possible future revisions. The following graph provides PUC's results.

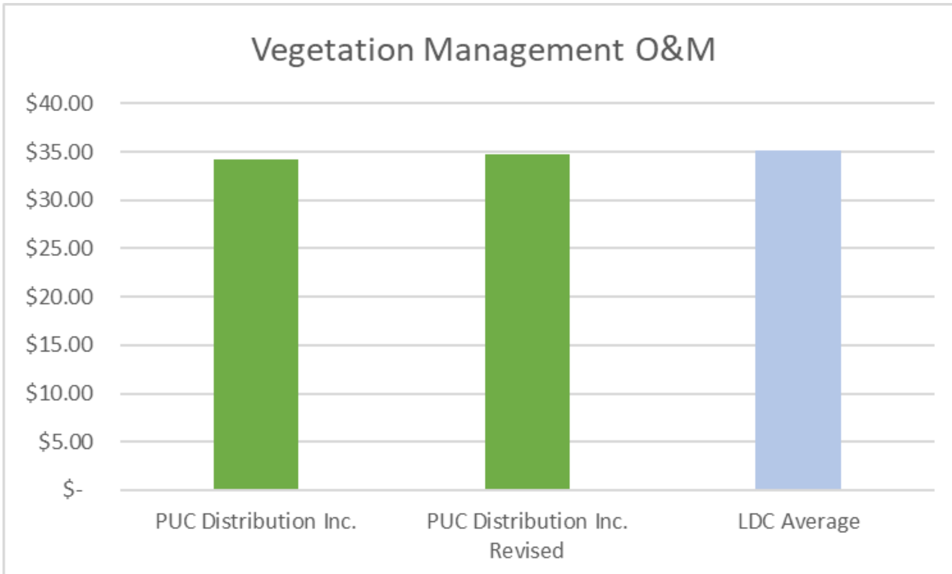
Figure 1-23: Metering O&M



Vegetation Management O&M

PUC's revised 3-year average for the years 2018-2020 for Vegetation Management O&M is $34.78 and $35.79 for 2019-2021. The average for LDC's as of 2020 is $35.11 making PUC just below the industry average. As part of PUC's 2018 COS application, it updated its vegetation management to a 4-year cycle. PUC has identified that its environmental features and plans will vary greatly thus creating difficulty in the comparison of results. PUC's results are also dependent on customer demand, and front vs. rear lot tree trimming. PUC is continually monitoring this metric for comparability and accuracy of reporting of information as to better create a like for like comparison in future years. The following graph provides PUC's results. As PUC is close to the LDC average, no immediate remedial action is required.

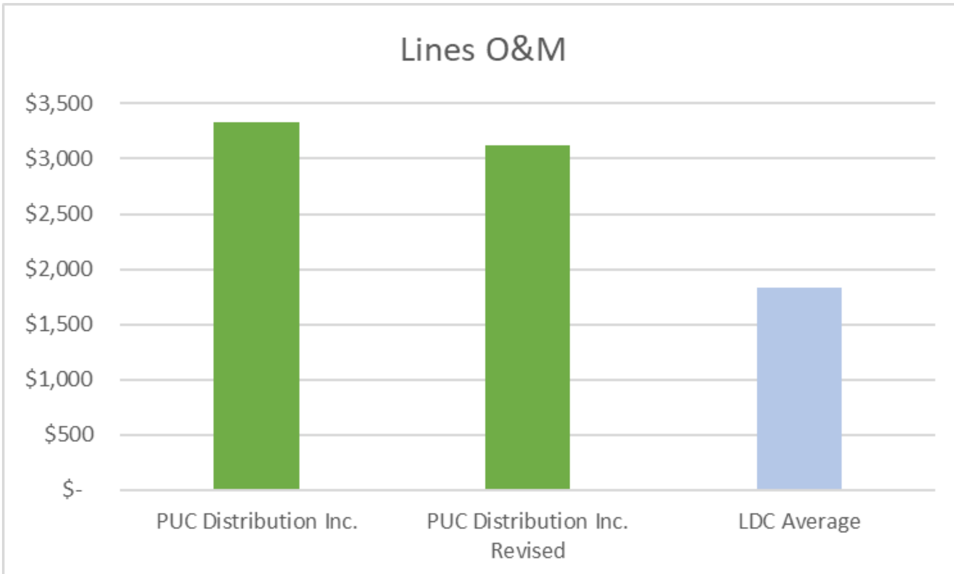
Figure 1-24: Vegetation Management O&M



Lines O&M

PUC's revised 3-year average for the years 2018-2020 is $3,121 and $3,069 for 2019-2021 for Lines O&M. The average for LDC's as of 2020 is $1,837 making PUC one of the higher amongst other LDC's. Upon review of PUC's results in this metric, it was determined that revisiting how PUC codes some work orders needs review as to properly align costs with the OEB's uniform system of accounts. This is an ongoing process. The following graph provides PUC's results.

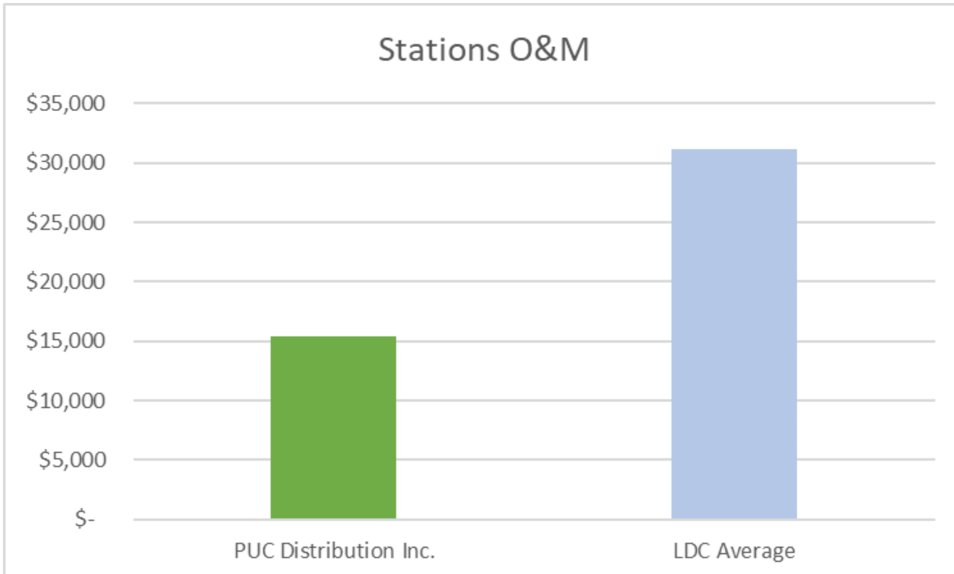
Figure 1-25: Lines O&M



Stations O&M

PUC 's 3-year average for the years 2018-2020 is $15,452 and $21,909 for 2019-2021 for Stations O&M. Many LDC's do not have the data for this metric and Hydro One is abnormally high. PUC has excluded those results from the LDC average. When PUC did an internal review of this category, it was determined that further analysis was required for the amounts going into the OEB accounts used as the numerator. Additionally, in 2020, PUC started a station maintenance program as a result of new standards. PUC also has 2 transmission stations that when comparing to other LDC's is unique to PUC. PUC will be looking to separate out the transmission costs to a separate sub account as to give a better comparison among LDC's. The following graph provides PUC's results. At this time no immediate remedial action is required.

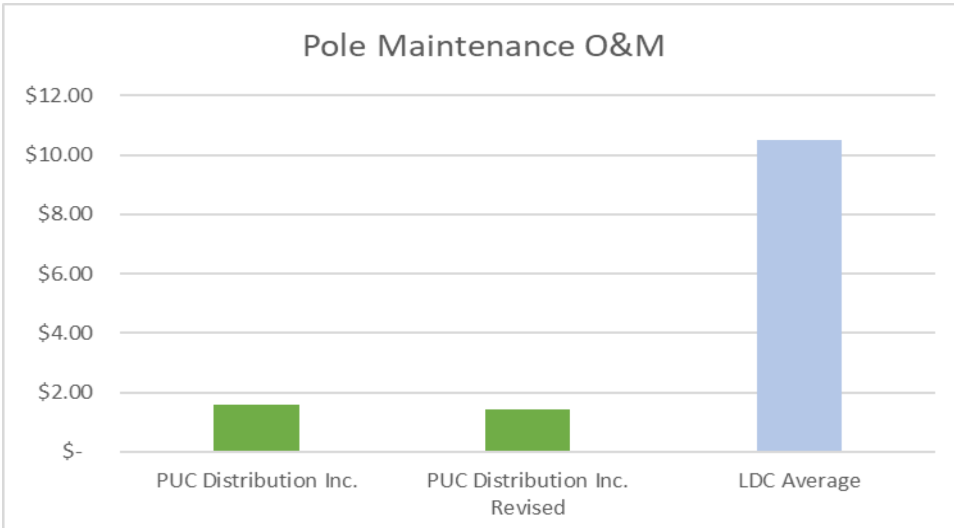
Figure 1-26: Station O&M



Pole Maintenance O&M

PUC's revised 3-year average for Pole Maintenance O&M for the years 2018-2020 is $1.43 and $1.00 for 2019-2021. The average for LDC's as of 2020 is $10.51 which makes PUC well below the industry average. As PUC is well below industry average, no immediate remedial action is required. The following graph provides PUC's results.

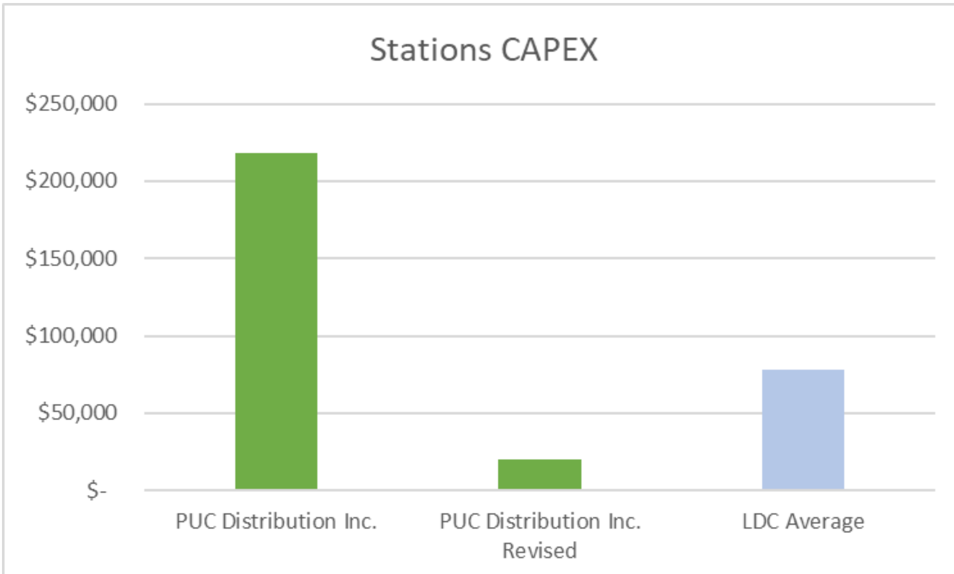
Figure 1- 27: Pole Maintenance O&M



Stations Capital Expenditures

PUC's revised 3-year average for Stations capital expenditures for the years 2018-2020 is $19,672 and $23,923 for 2019-2021. The revised PUC 3-year average is significantly different because PUC accidentally reported the total value of all OEB station fixed asset accounts rather than just the yearly additions. This revised PUC's result to significantly below the LDC average. Many LDC's do not have the data for this metric and Hydro One is abnormally high. Therefore, PUC has excluded them from the industry average. The following graph provides PUC's results. Since PUC is well below the industry average, no immediate remedial action is required.

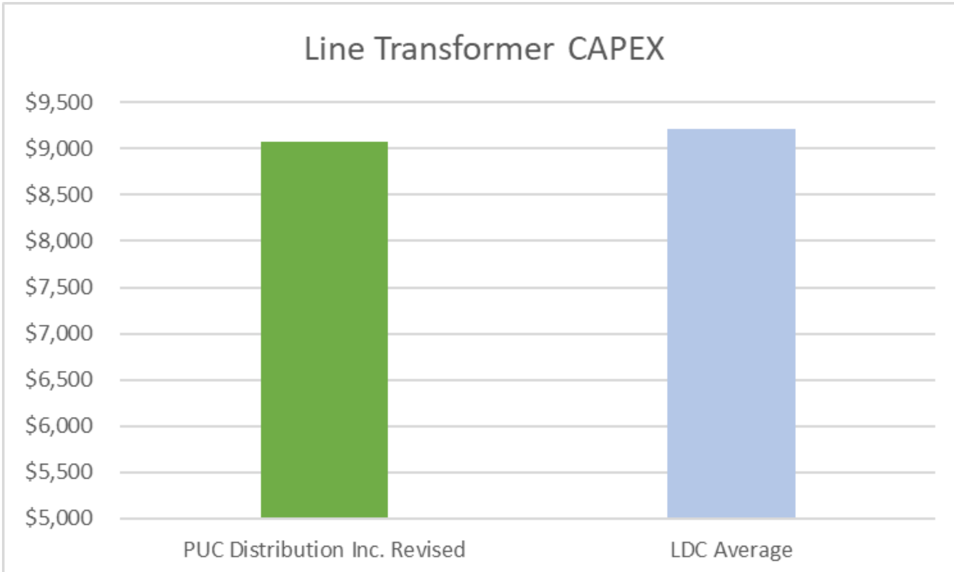
Figure 1-28: Stations CAPEX



Line Transformer Capital Expenditures

PUC originally was missing the data required for reporting in this category. Since the report has been published PUC has compiled the necessary data. PUC's revised 3-year average for Line Transformer capital expenditures for the years 2018-2020 is $9,068 and $9,122 for 2019-2021. The average for LDC's as of 2020 is $9,212 (excluding Alectra Utilities), which makes PUC below the industry average. PUC reviewed this category in further detail and believes it will have yearly fluctuations based on number of transformers due for PCB content, the number of transformers installed vs. put in inventory, and the type of transformer being installed. Also, comparison from one LDC to the next could be affected by high density vs low density areas, and localized utility programs. PUC will continue to monitor its results within this category but at this time no immediate remedial action is required. The following graph provides PUC's results.

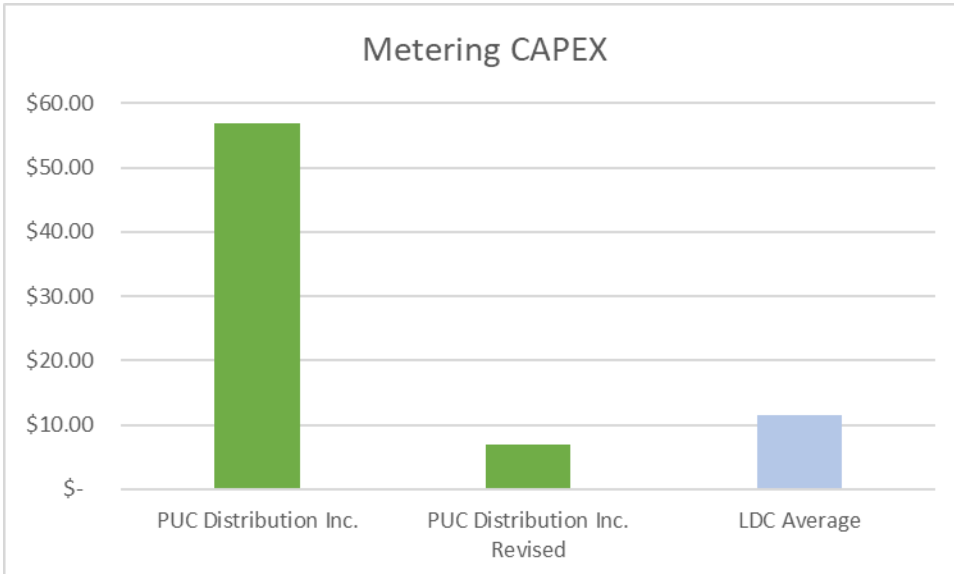
Figure 1-29: Line Transformer CAPEX



Metering Capital Expenditures

PUC accidentally reported total capital as opposed to 2020 only capital additions for this category. This results in PUC's being second highest for Metering capital expenditures. PUC's revised 3-year average for the years 2018-2020 is $6.91 and $7.59 for 2019-2021. The average for LDC's as of 2020 is $11.51 (excluding PUC incorrect amount and Hydro One) making PUC one of the lowest amongst other LDC's for Metering capital expenditures. As mentioned above PUC is looking into its capital versus expense accounting treatment of meter costs. This could have an impact on both metering O&M and capital expenditures results. At this time no immediate remedial action is required. The following graph provides PUC's results.

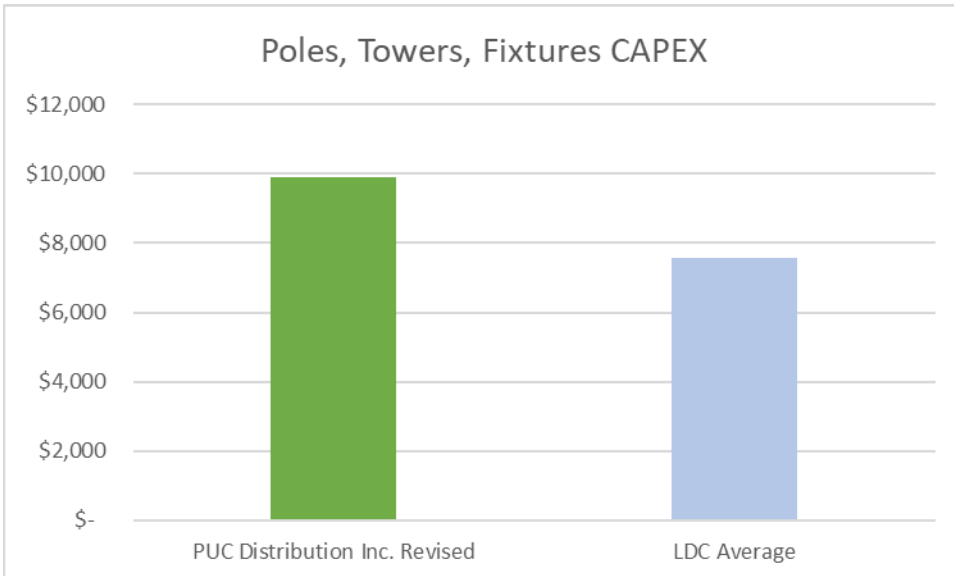
Figure 1-30: Metering CAPEX



Poles, Towers, Fixtures Capital Expenditures

PUC's revised 3-year average for Poles, Towers, Fixtures capital expenditures for the years 2018-2020 is $9,911 and $10,484 for 2019-2021. The average for LDC's as of 2020 is $7,568 making PUC slightly above average. Similar to the metering categories, PUC is higher in either capital expenditures or O&M for poles, towers and fixtures. PUC is undergoing a review of the items it capitalizes vs. expenses to gain a better understanding of its results in the two categories. At this time, no immediate remedial action is required. The following graph provides PUC's results.

Figure 1-31: Poles, Towers, Fixtures CAPEX



Comparison of PUC Distribution Rates (with TX) to Northern LDC's

PUC owns and operates its own transmission assets, which are deemed distribution assets. Therefore, PUC distribution takes service directly from Hydro One network assets and thus only has to pay the network service charge at the Hydro One Level. The additional RTSR rates that other LDC's may pay, Transmission Line and Connection and Low Voltage Rates, are not included in their service charge. Therefore, for comparability purposes PUC has compared its 2021 service charges including RTSR Network charge to other Northern LDC's, including applicable RTRS Network, Line Connection and Low Voltage Rates, in Table 1-37 below.

Table 1- 37: Comparison of PUC Distribution Rates (with TX) to Northern LDC's

Residential (750 kWh Monthly Bill)					
2021 Rates					
Rate	PUC	Greater Sudbury	North Bay	Synergy North - Thunder Bay	Average
Monthly Service Charge	32.74	29.99	32.64	25.63	30.25
Variable Rate	0	0	0		0
LV Rate	0.0000	0.0004	0.0002	0.0000	0.0001
RTSR Network	0.0076	0.0074	0.0086	0.0076	0.0078
RTSR Connection	0.0000	0.0053	0.0069	0.0054	0.0044
Monthly Bill Total	38.44	39.82	44.38	35.38	39.50

GS<50 (2000 kWh Monthly Bill)					
2021 Rates					
Rate	PUC	Greater Sudbury	North Bay	synergy North - Thunder Bay	Average
Monthly Service Charge	21.67	22.85	26.84	28.63	25.00
Variable Rate	0.026	0.022	0.0206	0.0186	0.0218
LV Rate	0	0.0003	0.0001	0	0.0001
RTSR Network	0.0071	0.0056	0.0082	0.0072	0.0070
RTSR Connection	0	0.0038	0.0061	0.005	0.0037
Monthly Bill Total	87.87	86.25	96.92	90.23	90.32

GS>50 (145 kW Monthly Bill)					
2021 Rates					
Rate	GS >50 to 4999 PUC	GS >50 to 4999 Greater Sudbury	GS>50 to 2,999 North Bay	GS>50 to 999 synergy North - Thunder Bay	Average
Monthly Service Charge	119.68	174.27	345.89	215.49	213.83
Variable Rate	7.0368	5.004	2.8704	3.5035	4.603675
LV Rate	0	0.2117	0.05359	0	0.0663
RTSR Network	2.8728	4.173	3.2616	2.8474	3.2887
RTSR Connection	0	2.8633	2.419	1.8971	1.7949
Total	1556.57	1950.81	1593.56	1411.45	1628.10

PUC's rates are second lowest and below the average of the four LDC's combined for the for all rate classes.

1.7 FACILITATING INNOVATION

PUC is continuously striving to use innovation in many business areas including, communication with its customers, internal business processes, driving costs savings and serving safe and reliable power to customers. PUC's five-year business plan strategic direction provides clarity, direction and focus connecting PUC's vision to improve communities through curiosity and innovation, with the company's core strategies and strategic objectives. The following sections outline how PUC is delivering on its promise to be innovative.

The environment in which PUC operates is constantly changing. Differing customer expectations paired with improved environmental pressures has required PUC to be responsive and adaptable, transforming at a rapid pace to meet the needs of today – and being prepared for tomorrow.

PUC's vision is to focus on sustainability in developing strategies to lower its carbon footprint, support its communities, and maintain exceptional customer service well into the future. Whether it is a health and safety initiative, a financial investment, community involvement, or an operational decision, PUC is always asking "how does this make the organization more sustainable, improve customer experience and tie to our long-term vision?".

PUC operates as a virtual utility which provides significant efficiency benefits across all of the utilities under the PUC umbrella. PUC Services Inc. shares certain resources with affiliates to create economies of scale and scope. By having such a corporate structure in place, it allows PUC Services Inc. to explore additional business opportunities further benefiting from the economies of scale.

SSG is an innovative project in itself by changing the way electricity is delivered which will help reduce customer bills and create better system reliability. SSG is a unique project because it is the first of its kind in Canada. PUC's strategic approach allowed it to take advantage of NRCAN funding equal to 25% of the project value. This is innovating because it allows PUC to add VVO savings and DA, while ensuring a bill neutral impact. Over time, the benefits of this project only increases to customers as the NBV of the assets begin to decrease and the cost of power is expected to increase.

PUC's customers can now report outages quickly and easily on the MyPUC app, and the results are quicker response times to restore power. Updates provided through the App improves customer experience by eliminating the unknown. Since its launch in July 2021, thousands of PUC customers are using the APP, conserving more energy and enjoying a better overall experience through their community utility.

With COVID-19, PUC had to adapt quickly to be able to continue operating during the pandemic with most of its office workers at home. This caused a number of paperless initiatives to result and solutions to be created that have streamlined processes. Many departments implemented process improvements that have carried on now that employees have returned to the office. For example, PUC implemented a "Office in a Truck" where employees in the field are equipped with an IPAD and cell phone to better process work orders and communicate remotely. Another example, in Finance most processes were digitized. PUC's goal is to become a paperless operation by 2024.

PUC has partnered with Demand Power Group Inc. to help the Sault Area Hospital with a new innovative program that will save millions on energy costs. The Customer Energy Management (CEMa) program will help larger customers reduce their electricity bill by providing improved power reliability and quality while reducing energy through the use of a battery energy storage system. This will allow the customer to store electricity during off peak hours and use it during peak rate times.

PUC was a leader in promoting the Affordability Fund Trust program amongst LDC's in Ontario. The goal of the program was to help Ontarians who did not qualify for low-income programs but wanted to conserve energy to help reduce their electricity bills. The AFT program had an overall positive impact on the energy use within the community. PUC and the AFT were able to provide energy saving measures to 6,800 residences in Sault Ste Marie which, represented 8% of the total provincial uptake for the program.

PUC is constantly looking to make improvements across its organization that will result in increased quality, productivity, customer satisfaction, employee/customer safety, and employee morale. It's vision of "improving communities through curiosity and innovation" speaks to making innovation a priority.

1.8 FINANCIAL INFORMATION

Non-Consolidated Audited Financial Statements

PUC has included its non-consolidated Audited Financial Statements ("AFS") for the years 2020 and 2021 as Appendix G and H respectively.

Annual Report and MD&A for Parent Company

PUC Inc. does not have an updated Annual Report and MD&A. PUC Services completed an annual sustainability report that encompasses all of PUC's group of companies. The 2021 annual report is attached as Appendix I.

Rating Agency Reports

PUC does not hold public debt, therefore, does not require a rating agency report.

Prospectus, Information Circulars for Recent and Planned Issuances

PUC has no past or planned prospectuses, information circulars, or other similar documents.

Changes in Tax Status

PUC has not had a change in Tax Status since its 2018 COS Application.

Existing Accounting Orders

PUC confirms that is has applied the accounting principles from the Board's Accounting Procedures Handbook. PUC has one specific accounting order from its 2021 ICM application for SSG (EB-2018-0219/EB-2020-0249). This accounting order is attached as Appendix A in Exhibit 9. PUC has and will continue to follow this accounting order for the completion of the SSG project in 2022.

Uniform System of Accounts

PUC confirms there are no departures from the Uniform System of Accounts.

Accounting Standards

PUC transitioned to IFRS on January 1, 2015. This Application is being filed using MIFRS Accounting Standards. PUC has prepared its historical financial statements from 2018 to 2021 along with the 2022 bridge year and 2023 test year in accordance with the Modified International Financial Reporting Standards ("MIFRS").

Accounting Treatment of Non-Utility Businesses

PUC confirms that it does not have any non-utility business activities.

1.9 DISTRIBUTOR CONSOLIDATION

PUC confirms that it has not been a party to a Merger, Amalgamation, Acquisition, or Divestiture transaction with any other distributor(s) since its last rebasing application.

1.10 IMPACTS OF COVID-19 PANDEMIC

On March 11, 2020, the World Health Organization declared the COVID-19 outbreak a global pandemic. This pandemic had a huge impact on all of PUC's departments and overall business continuity plan. PUC began action in response to COVID-19 at the end of March 2020 when it began setting up employees in a work from home environment for those who were able. PUC enacted a multitude of business continuity plans in order to protect the safety of its workers and to continue to operate a safe and reliable distribution system. However, PUC operations and spending plans had to be adjusted to accommodate the changing landscape of the pandemic. Some of the items are highlighted below. The paragraphs to follow outline how PUC was affected in terms of its load forecast, OM&A, business operations, and capital spending and planning.

Load Forecast

PUC first prepared its load forecast using historical actuals up to the end of 2021. Upon completion of the regression analysis and resulting output, PUC felt it had to make an adjustment in 2020 and 2021 to account for the change in consumption and customers that resulted from the COVID-19 pandemic. As a result, PUC updated its load forecast after normalizing the consumption and customer amounts for the small and large general service classes for 2020 and 2021. Full details of the changes can be reviewed in Exhibit 3 Subsection 1 – COVID Findings in Regression Analysis.

<u>OM&A and Business Continuity</u>

PUC's Executive and Management teams were focused in constantly reviewing of, monitoring of, and adapting to the working environment to ensure the safety of employees and its service to its customers. A cross-functional team was created for this purpose. Upfront and most critical was the update of Business Continuity plans, workplace policies and accommodations for staff.

PUC invested in the additional health and safety of its workers by allowing them to work from home. This required a transition that increased costs to accommodate the work from home environment. PUC also mandated certain rules around exposure of its workforce to COVID 19 requiring some workers to isolate if exposed. Employees were offered flexible arrangements to accommodate various personal requirements. Field workers were assigned to pods to reduce the exposure or cross infection if a worker were to get sick. As with most businesses, PUC purchased the necessary products to keep its workers safe such as masks, gloves, cleaners and sanitizing products. All of these measures were different from PUC's normal course of duties that made up its existing OM&A budget and thus had an impact on 2020 and 2021 OM&A results.

OM&A was also impacted by regulatory and billing changes mandated by the OEB. The OEB enacted emergency TOU pricing a few different times during the COVID-19 pandemic requiring multiple billing updates not accounted for. The OEB also made available additional LEAP funding to customers who qualified under the OEB's new guidance. This required the processing of many applications to determine if customer qualified for additional Leap funding.

From a regulatory perspective, the OEB issued an emergency accounting order on March 25, 2020 acknowledging that distributors may incur incremental costs as of the result of the ongoing covid-19 pandemic. The OEB also required LDC's to complete monthly reporting for a period of 1 year to ensure that each LDC could continue to operate from a cash flow perspective during the pandemic.

During the pandemic, the OEB suspended disconnections until September 1, 2020. PUC increased the threshold for disconnection during the period from September 1, 2020 and the moratorium date of November 14, 2020 resulting in minimal disconnections. For some individuals and businesses, the pandemic has resulted in financial hardship and as a result PUC has seen greater challenges for customers to pay their bills. Despite government programs available to assist customers, PUC has seen an increasing trend in non-payment of accounts which has created larger overdue accounts and bad debts that PUC continues to manage.

Capital Spending and Planning

As outlined in detail in Exhibit 2 Section 2.1.8 PUC had to delay the replacement of Sub-16 by one year to protect the health and safety of its workers. This caused increased costs with the project that are proposed for reconciliation as part of this application.

Summary

PUC felt additional impacts from the COVID -19 pandemic that it continues to deal with today.

The entire economy continues to deal with the effects of the COVID-19 pandemic. There are supply constraints that PUC continues to navigate, rapidly increased pricing on infrastructure and the rising cost of inflation that has not slowed in recent months. PUC continues to address these issues each day with the close monitoring of its budget, the health and safety of its employees and the longer-term cash flow forecasting as presented in its budget. A global health pandemic risk is one of the top ten risks that the company actively updates its mitigation plans (CFO is the accountable risk owner) and PUC believes it is prepared to adapt accordingly.

APPENDIX A

2023 Cost of Service

Checklist

2023 Cost of Service Checklist

PUC Distribution Inc.

EB-2022-0059

Date: 2022 08 31

Filing Requirement Page # Reference		Evidence Reference, Notes (Note: if requirement is not applicable, please provide reasons)
GENERAL REQUIREMENTS		
Ch1, p4	Confidential Information - Practice Direction has been followed	Exhibit 1, Section 1.3.1 - Appendix C, Executive Certification
Ch1, p5	Certification by a senior officer that the application and any evidence filed in support of the application does not include any personal information unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction, as applicable).	Exhibit 1, Section 1.3.1 - Appendix C, Executive Certification
Ch1, p5	Certification by a senior officer that the evidence filed (including the models and appendices) is accurate, consistent and complete to the best of their knowledge	Exhibit 1, Section 1.3.1 - Appendix C, Executive Certification
Ch1, p5	Certification by the Chief Executive Officer, or Chief Financial Officer, or equivalent, that the distributor has the appropriate processes and internal controls for the preparation, review, verification and oversight of all deferral and variance accounts, regardless of whether the accounts are proposed for disposition	Exhibit 1, Section 1.3.1 - Appendix C, Executive Certification
Ch2, p2	COS checklist filed and statement identifying all deviations from Filing Requirements	Exhibit 1, Section 1.3.9 - Changes in Methodology - no deviations
2 & 3	Chapter 2 appendices in live Excel format; PDF and Excel copy of current tariff sheet	Live Excel file "PUC_2023_Filing_Requirements_Chapter2_Appendices_20220831.pdf Current and Proposed Tariff Sheets in Exhibit 8, Appendix B and Appendix C
3	If distributor updates/amends an OEB model, reference made in corresponding exhibit re: what was amended	N/A
3	Regulated entity shown separately from parent company or any other affiliates	Not filing for rate year alignment in this rate application, PUC aligned its rate year to its calendar year in its 2022 rate application.
3	If applicable, if cost of service filed earlier than scheduled, threshold for early rebasing as established in April 2020 letter met	N/A
4	If applicable, late applications filed after the commencement of the rate year for which the application is intended to set rates is converted to the following rate year	N/A
4	All of the following exhibits filed: Administrative Documents, Rate Base (including DSP), Customer and Load Forecast, Operating Expenses, Cost of Capital and Capital Structure, Revenue Requirement and Revenue Deficiency/Sufficiency, Cost Allocation, Rate Design, Deferral and Variance Accounts	Confirmed
5	General requirements applicable throughout application: -written evidence included before data schedules -avg. of opening and closing fiscal year balances used for items in rate base (unless alternative method justified) -debt + equity = total rate base -data for test year, bridge year, three most recent historicals (or as many needed to provide actuals back to last OEB-approved), most recent OEB-approved test	Confirmed
5	Text searchable and bookmarked PDF documents	Confirmed all PDF's filed in accordance with this requirement
6	Links within Excel models are broken and models named so that they can be identified (e.g. RRWF instead of Attachment A)	Confirmed Excel models have no broken links Files identified by model name.
6	Materiality threshold; explanations for rate base, capex, and OM&A if revenue requirement impact is greater than the materiality threshold; additional details below the threshold if necessary	Exhibit 1, Section 1.3.14 - Materiality Threshold
EXHIBIT 1 - ADMINISTRATIVE DOCUMENTS		
Table of Contents		
7	Table of Contents listing major sections and subsections of the application	Filed as Separate PDF
Application Summary and Business Plan		
7	Distributor with less than 30k customers: Business and/or Strategic Plan. If no Business or Strategic plan: key planning assumptions, description of material factors (internal and external) that may affect the operation of the utility and major goals of the distributor in the test year and remaining years of the five-year term. Distributor with 30k or more customers: Business Plan underpinning application - can be augmented by plain language summary of distributor's goals that informed the application if this is not otherwise in the business plan.	Exhibit 1, Section 1.2 Executive Summary and Business Plan Appendix B - PUC's 5 Year Business Plan
7 & 8	Brief, plain langauge summary of the application which includes the main requests with section references and rationale behind each request. Must include: -Revenue requirement (service revenue requirement requested for test year, increase/decrease ($ and %) from most recent approved, main drivers of revenue requirement changes -Load forecast summary (load and customer growth (% change in kWh, kW and change in customer #s from last OEB-approved)) -Rate base and DSP (major drivers of DSP, rate base requested, change in rate base from last OEB-approved ($ and %), CAPEX for test year, change in CAPEX from last OEB-approved ($ and %) -OM&A (OM&A for test and change from last OEB-approved ($ and %), drivers and cost trends) -Cost of capital (table showing proposed capital structure and parameters resulting in WACC, statement confirming use of OEB's cost of capital parameters, summary of deviations from OEB methodology) -Cost allocation and rate design (proposed new customer classes and/or customer definition changes, significant changes proposed to rev. cost ratios and fixed/variable split, mitigation plans) -DVAs (total disposition ($) including split between RPP and non-RPP, disposition period, new DVAs and requested discontinuation of DVAs) -Bill Impacts ($ and %) for residential customer at 750kWh, and typical customers for all other classes (based on commodity rates on TOU with regulatory charges held constant; bill impacts to be used for Notice (Sub-total A) for residential customer at 750kWh and GS<50 at 2000kWh as well as a typical consumer for a distributor's service area for all customer classes, and bill impacts based on alternative consumption profiles and customer groups as appropriate	Exhibit 1 Section 1.2
Administration		
9	Primary contact information (name, address, phone, email)	Exhibit 1 Section 1.3.2
9	Identification of legal (or other) representation	Exhibit 1 Section 1.3.3
9	Applicant's internet address for viewing of application and any social media accounts, with addresses, used by the applicant to communicate with customers	Exhibit 1 Section 1.3.4
9	Statement identifying where notice should be published and why	Exhibit 1 Section 1.3.6
9	Form of hearing requested and why	Exhibit 1 Section 1.3.6
9	Requested effective date	Exhibit 1 Section 1.3.8
9	Statement identifying and describing any changes to methodologies used vs previous applications	Exhibit 1 Section 1.3.9
9	Identification of OEB directions from any previous OEB Decisions and/or Orders, including commitments made as part of approved settlements. Indication of how these are being addressed in the current application	Exhibit 1 Section 1.310
9	Reference to Conditions of Service - provide reference to website and confirm version is current; identify if there are changes to Conditions of Service (a) since last CoS application and/or (b) as a result of the current application. Confirmation that there are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges must be provided	Exhibit 1 Section 1.3.11
9 & 10	Description of the corporate and utility organizational structure showing the main units and executive and senior management positions within the distributor; corporate entities relationship chart, showing the extent to which the parent company is represented on the distributor company's Board of Directors; description of the reporting relationships between distributor and parent company management. Also include any planned changes in corporate or operational structure, including any changes in legal organization and control	Exhibit 1 Section 1.3.12
10	List of approvals requested (and relevant section of legislation). All approvals including accounting orders, new rate classes, revised specific service charges or retail service charges which the distributor is seeking, must be documented - Appendix 2-A provided, but not required to be used by LDC	Exhibit 1 Section 1.3.13
Distribution System Overview		
10	Description of Service Area - general description and map showing where distributor operates and communities served	Exhibit 1 Section 1.4
Customer Engagement		
10	Discussion on how utility communicates with customers on a regular basis	Exhibit 1 Section 1.5
10	Discussion on how the proposals in the application were communicated to customers	Exhibit 1 Section 1.5
10	Discussion of any feedback provided by customers and how the feedback informed the final application	Exhibit 1 Section 1.5
10	Customer consultation with customers who would be affected by proposals related to new classes, elimination of classes, change in class definition, and change in charges such as RSCs, Specific Service Charges and standby rates	N/A
10	Documentation of communications with unmetered load customers (incl. Street lighting), and how distributor helped them to understand the regulatory context in which the distributor operates and how it affects unmetered scattered load customers	Exhibit 1 Section 1.5
10	Description of any other communication sent to customers about the application such as bill inserts, town hall meetings or other forms of outreach. Appendix 2-AC Customer Engagement Activities Summary **may** be used to assist in listing customer engagement activities	Exhibit 1, Section 1.5 and Chapter 2 Appendices 2-AC
11	All responses to matters raised in letters of comment filed with the OEB	N/A, No letters of comment recent from customers.

Performance Measurement		
11	Link to most recent scorecard	Exhibit 1 Section 1.6.2
11	Identification of performance improvement targets	Exhibit 1 Section 1.6 Target explained at end of each scorecard section
11	PEG Model for the test year showing efficiency assessment, discussion on how the results obtained from the PEG model has informed the distributor's business plan and application	Exhibit 1 Section 1.6.2
11	Distributors **may** wish to provide table showing respective OEB-approved IRM increases for each of the last historical years from last rebasing, and assigned cohort as per PEG model	Exhibit 1 Section 1.6.2
11	Activity and Performance-based Benchmarking (APB) results - discussion of performance for each of the ten programs and provide any immediate remedial actions distributor plans to take; how the APB results will influence future planning	Exhibit 1 Section 1.6.7
Facilitating Innovation		
12	Distributors are encouraged to include a description of the ways their approach to innovation have shaped the application. Could include an explanation of approach to innovation in its business more generally, or related to specific projects or technologies, including enabling characteristics or constraints in its ability to undertake innovative solutions, for enhancing the provision of distribution services in a way that benefits customers, or facilitating customers ability to innovate in how it receives electricity. Distributors could also include an explanation of how innovative alternatives have been considered in place of traditional investments.	Exhibit 1 Section 1.7
Financial Information		
12 & 13	Audited Financial Statements (excluding operations of affiliated companies that are not rate regulated) for two most recent historical years (i.e. one year's statements must be filed, covering two years of historical actuals); if most recent finals n/a, draft financial statements filed and finals, along with summary of main changes if there are any, provided as soon as they are available. Alternatively, if distributor publishes financial statement on its website, a link may be provided	Exhibit 1 Section 1.8
13	Annual Report and MD&A for most recent year of distributor and parent company, as available and applicable	Exhibit 1 Section 1.8
13	Rating Agency Reports, if available; Prospectuses, information circulars etc. for recent and planned public issuances	Exhibit 1 Section 1.8
13	Any change in tax status	Exhibit 1 Section 1.8
13	Description of existing accounting orders and departures from these orders, as well as any departures from the USoA	Exhibit 1 Section 1.8
13	Accounting Standards used for financial statements and when adopted	Exhibit 1 Section 1.8
13	If distributor conducting non-distribution businesses, confirmation that accounting treatment used has segregated these activities from rate regulated activities	Exhibit 1 Section 1.8, PUC does not have any non utility business activities
Distributor Consolidation		
13	Distributor with less than 30k customers: information filed on the extent to which the distributor has investigated opportunities from consolidation or collaboration/partnerships with other distributors (contained within a dedicated section of the application); conclusions from investigations, including future plans	Exhibit 1 Section 1.9 PUC has not been a party to a Merger, Amalgamation, Acquisition, or Divestiture transaction with any other distributor(s) since its last rebasing application
13	If distributor has become party to a proposed or approved MAADs transaction since last rebasing, disclosure of this information in current application	
A distributor filing an application to rebase following a consolidation must:		
14	Identify any incentives that formed part of the acquisition or amalgamation transaction if the incentive represents costs that are being proposed to remain or enter rate base and/or revenue requirement - list the exhibits in which incentives are discussed	
14	Specify whether and which commitments made to shareholders are to be funded through rates	
14	Detail of realized and projected savings as a result of consolidation compared to what was in the approved consolidation application and explanation of the nature of these savings (e.g. one-time, ongoing etc.)	
14	Detail of efficacy of any rate plan confirmed as part of MAADs	
14	Identify approved ACM or ICM from a previous Price Cap IR application it proposes be incorporated into rate base	
Impacts of COVID-19 Pandemic		
14	Distributors generally expected to reflect the impacts of the COVID-19 pandemic in their applications, including applicable forecasted information. This includes, but is not limited to, the applicant's load forecast, capital forecast, and OM&A forecast in the applicable sections of the application	Exhibit 1 Section 1.10
EXHIBIT 2 - RATE BASE		
Rate Base		
14	Indication of whether capital expenditures are equivalent to in-service additions, and if so, variance explanations only required once. Specify whether variance explanations are on CAPEX or in-service additions basis	Exhibit 2, Section 2.1
14 & 15	For rate base, opening and closing balances for each year, and the average of the opening and closing balances for gross assets and accumulated depreciation (discussion of methodology if applicant uses an alternative method); working capital allowance	Exhibit 2, Section 2.1 Table 2-3
15	Table showing components of the last OEB-approved rate base, the proposed test year rate base and the variances	Exhibit 2, Section 2.1 Table 2-2
Fixed Asset Continuity Schedule		
15	Completed Appendix 2-BA for each year - in Excel format	Live Excel file "PUC_2023_Filing_Requirements_Chapter2_Appendices_20220831.pdf
15	Continuity statements and year-over-year variance analysis must be provided (year end balance, including capitalized interest during construction and overhead costs). Explanations provided where there is a year-over-year variance greater than the applicable materiality threshold If applicable, explanation for any restatement (e.g. due to change in accounting standards) and reconciliation to original statements Year over year variance analysis; explanation where variance greater than materiality threshold. The following comparisons must be provided: Hist. OEB-Approved vs Hist. Actual (for the most recent historical OEB-approved year) Hist. Act. vs. preceding Hist. Act. (for the relevant number of years) Hist. Act. vs. Bridge Bridge vs. Test	Exhibit 2, Section 2.2
15	Opening and closing balances of gross assets and accumulated depreciation correspond to fixed asset continuity statements. If not, an explanation and reconciliation must be provided (e.g. CWIP, ARO). Reconciliation must be between net book value balances reported on Appendix 2-BA and balances included in rate base calculation	Exhibit 2, Section 2.2 Table 2-4
15	Distributor may include in-service balances previously recorded in DVAs, such as renewable generation/smart grid related accounts, in its opening test year property, plant and equipment balances, if these costs have not been previously reviewed and approved for disposition, and disposition is being requested in this application. In this situation, the distributor must clearly show in its evidence (e.g. Appendix 2-BA) that the addition was included in the opening test year balances and must reconcile the closing bridge year and opening test year figures. Distributors must provide the same reconciliation for accumulated depreciation	Exhibit 2, Section 2.2
Gross Assets - PP&E and Accumulated Depreciation		
16	Groupings by function (transmission or high voltage plant, distribution plant, general plant, other plant) for required statements and analyses	Exhibit 2, Section 2.3
16	Componentization by major plant account for each functionalized plant item; for test year, each plant item must be accompanied by description	Exhibit 2, Section 2.3
16	Summary of approved and actual costs for any ICM(s) and/ or ACM approved in previous IRM applications	Exhibit 2, Section 2.3
16	Continuity statements must reconcile to calculated depreciation expenses and presented by asset account	Exhibit 2, Section 2.3 Tables reconcile to Chapter 2 Appendices
16	All asset disposals clearly identified in the Chapter 2 Appendices for all historical, bridge and test years	Live Excel file "PUC_2023_Filing_Requirements_Chapter2_Appendices_20220831.pdf
Depreciation, Amortization and Depletion		
17	Explanations for any useful lives of an asset that are proposed that are not within the ranges contained in the Kinectrics Report	Exhibit 2 Section 2.4
17	Depreciation, amortization and depletion details by asset group for historical, bridge and test years. Include asset amount and rate of depreciation/amortization. Must complete Appendix 2-C which must agree to accumulated depreciation in Appendix 2-BA under rate base	Exhibit 2 Section 2.4
17	Identification of any Asset Retirement Obligations and associated depreciation or accretion expense - includes the basis for and calculation of these amounts	Exhibit 2 Section 2.4
17	Identification of historical depreciation practice and proposal for test year. Variances from half year rule must be documented and supporting rationale provided	Exhibit 2 Section 2.4
17	Copy of depreciation/amortization policy if available. If not, equivalent written description; summary of changes to depreciation/amortization policy since last CoS	Exhibit 2 Section 2.4
17	If filing under MIFRS, explanation of any deviations from the practice of depreciating significant parts or components of PP&E separately	Exhibit 2 Section 2.4
18	If no changes have been made to depreciation policy or service lives since last rebasing, a statement confirming that this is the case is required. For any depreciation expense policy or asset service lives changes since its last rebasing application: - identification of the changes and detailed explanation for the causes of the changes -use of Kinectrics study or another study to justify changes in useful life - list detailing all asset service lives tied to USoA and reconcile this list to the USoA, detail differences in asset service lives and the TULs from Kinectrics and explain differences outside of minimum and maximum TUL range from Kinectrics; Appendix 2-BB if there have been changes in asset service lives since last rebasing	Exhibit 2 Section 2.4

Allowance for Working Capital				
	18		Working Capital - 7.5% allowance or Lead/Lag Study or Previous OEB Direction	Exhibit 2, Section 2.5
	18		Lead/Lag Study - leads and lags measured in days, dollar-weighted and reflects the distributor's actual billing and settlement processing timelines and considers relevant changes to operating environment	Exhibit 2, Section 2.5
	19		Cost of Power must be determined by split between RPP and non-RPP Class A and Class B customers based on actual data, use most current RPP (TOU) price. Calculation must include the impact of the most up to date Ontario Electricity Rebate. Distributors must complete Appendix 2-Z - Commodity Expense.	Exhibit 2, Section 2.5
	19		Use most recent approved UTRs, Smart Metering Entity Charge and regulatory charges	Exhibit 2, Section 2.5
Distribution System Plan				
	19		DSP filed as a stand-alone, self-sufficient element within Exhibit 2	Exhibit 2 Section 2.6 and Appendix C
Policy Options for the Funding of Capital				
	19		Distributor may propose ACM capital project coming into service during Price Cap IR (a discrete project documented in DSP) - provide information on need and prudence	Exhibit 2 Section 2.7
	19		Identification that distributor is proposing ACM treatment for these future projects, and provide the preliminary cost information and ACM/ICM materiality threshold calculations - ACM Report provides further details on information required	
	19		Complete Capital Module Applicable to ACM and ICM	
Addition of Previously Approved ACM and ICM Project Assets to Rate Base				
	20		Distributor with previously approved ACM(s) and/or ICM(s) - schedule of ACM/ICM amounts proposed to be incorporated into rate base (i.e. PP&E and associated depreciation). Comparison of actual capital spending with OEB-approved amount and explanation for variances	Exhibit 2 Section 2.8
	21		Balances in Account 1508 sub-accounts; rate of interest prescribed by the OEB for DVAs for the respective quarterly period as published on the OEB's website	
	21		True-up calculation if material, comparing the recalculated revenue requirement based on actual capital spending relating to the OEB-approved ACM/ICM project(s) to the rate rider revenues collected in the same period; assumptions used in the calculation noted (e.g. half-year rule).	
	21		Accelerated capital cost allowance (CCA) should not be reflected in the ACM/ICM revenue requirement associated with these projects. Distributors should include the impact of the CCA rule change associated with the ACM/ICM project(s) in Account 1592 - PILs and Tax Variances – CCA Changes sub-account for CCA changes	
Capitalization				
	22		Capitalization Policy: provide policy including changes since last rebasing application	Exhibit 2 Section 2.9
	22		Overhead Costs: complete Appendix 2-D	Live Excel file "PUC_2023_Filing_Requirements_Chapter2_Appendices_20220831.pdf
	22		Burden Rates: identification of burden rates; if burden rates were changed since last rebasing, identification of the burden rates prior to the change	Exhibit 2 Section 2.9
Costs of Eligible Investments for the Connection of Qualifying Generation Facilities				
	22		See Appendix A	Exhibit 2 Section 2.10
General & Administrative Matters				
	Ch5, p2		Use of terminology and formats set out in Ch. 5	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan
Investment Categories				
	Ch5, pp 2, 3 & 4		Investment projects and programs grouped into one of four investment categories (i.e. system access, system renewal, system service, general plant)	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan
Distribution System Plan				
	Ch5, p4		If a distributor's application uses alternative section headings and/or arranges the information in a different order, table provided that cross-references the headings/subheadings used in the application to the section headings/subheadings indicated in Ch. 5	N/A - The DSP follows the chapter and section headings in accordance with the Ch 5. Filing Requirements.
	Ch5, p4 & 5		DSP duration minimum of 10 years, comprising of a historical and forecast period. The historical period is the first five years of the DSP duration, consisting of five historical years, ending with the bridge year. For distributors that have not filed a DSP within the past five years, the historical period is from the test year of a distributor's last cost or service application to the bridge year. The forecast period is the last five years of the DSP duration, consisting of five forecast years, beginning with the test year.	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan
Distribution System Plan Overview				
	Ch5, p5		High-level overview of information filed in DSP which includes capital investment highlights and changes since last DSP; objectives distributor plans to achieve through DSP	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 2.1
Coordinated Planning with Third Parties				
	Ch5, p5		Demonstration of OEB's expectations related to coordinated planning with third parties where appropriate. Explanation of whether consultations affected distributor's DSP, and if so, how; for consultations that affected DSP - overview of consultation, material used, copy of final deliverable if available	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.2
	Ch5, p5		Description of consultation should include: purpose, whether the distributor initiated the consultation or was invited to participate in it, and the other participants in the consultation process	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.2
	Ch5, p5 & 6		Identification of any inconsistencies between DSP and any current Regional Plan. If there are any inconsistencies, explanation of the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.2.3
	Ch5, p6 & OEB Letter, Jan. 11, 2022		Telecommunications Entities: -see January 11, 2022 letter for 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	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.2.4
	Ch5, p6		REG: -confirmation if there are no REG investments in region -if there REG investments proposed in DSP, demonstration of coordination with IESO, other distributors/transmitters (as applicable), and that investments proposed are consistent with Regional Infrastructure Plan - IESO letter in relation to REG investments	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.2.6; Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Appendix F & Appendix G
Performance Measurement for Continuous Improvement				
	Ch5, p6		Distribution System Plan: Summary of objectives for continuous improvement set out in last DSP and discussion on whether these objectives achieved or not. For objectives not achieved, explanation of how this affects current DSP and if applicable, improvements implemented to achieve the objectives in current DSP	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.3.1
	Ch5, pp 6 & 7		Service Quality and Reliability: -5 historical years of SQRs; explanations for material changes in service quality and reliability and whether and how DSP addresses these issues -for reliability, any declining 5 year SAIDI/SAIFI trends explained -if reliability targets established in last DSP, any under-performance explained	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.3.2
	Ch5, p7		Completed Appendix 2-G; confirmation that the data is consistent with scorecard, or explanation of any inconsistencies	Live Excel file "PUC_2023_Filing_Requirements_Chapter2_Appendices_20220831.pdf
	Ch5, p7		Summary of performance for historical period using methods and measures (metrics/targets) identified and how performance has trended over the period. 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: SAIFI, SAIDI	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.3.2
	Ch5, p7		Summary of major events that occurred since last cost of service	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.3.2.3
	Ch5, p7		For each cause of interruption for last five historical years: number of interruptions that occurred as a result of the cause of interruption, number of customer interruptions that occurred as a result of interruption, number of customer-hours of interruptions that occurred as a result of the cause of interruption	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.3.2.3
	Ch5, pp7 & 8		Distributor Specific Reliability Targets: -if establishing performance expectations based on something other than historical performance, evidence provided of capital and operational plan and other factors that justify the reliability performance the distributor plans to deliver -summary of any feedback from customers regarding reliability on distributor's system -distributors that use SAIDI and SAIFI performance benchmarks that are different than the historical average - evidence provided to support reasonableness of benchmarks	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.2.3.4

Planning Process		
Ch5, p8	Overview of planning process that has informed five-year capital expenditure plan; flowchart accompanied by explanatory text **may** be helpful	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.1.1
Ch5, p8	Summary of important changes in distributor's AM process since last DSP	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.1.2
Ch5, p8 & 9	Process: -provide processes used to identify, select, prioritize (including reprioritization over 5 year term), and pace execution of investments -demonstration that distributor has considered correlation between plan and customer's feedback and needs -demonstration that distributor has considered potential risks of proceeding/not proceeding with individual capital expenditures -consideration, where applicable, of assessing the use of non-distribution alternatives, cost-effective implementation of distribution improvements affecting reliability, and meeting customer needs as acceptable costs to customers, other innovative technologies, and consideration of dx funded CDM activities	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.1.3
Ch5, p9	Data -identification, description and summary of data used in processes above to identify, select, prioritize and pace investments over DSP	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.1.4
Overview of Assets Managed		
Ch5, p9	Overview of service area (e.g. system configuration, urban/rural etc.) to support capital expenditures over forecast period; asset information (e.g. capacity, condition, asset risks etc.) by major asset type that may help explain the specific need of the capital expenditure and demonstration of consideration of economical alternatives	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.2; Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Appendix H
Ch5, p9	Statement as to whether or not distributor has had any transmission or high voltage assets deemed previously by the OEB as distribution assets, and whether or not there are any such assets that the distributor is asking the OEB to deem as distribution assets in the current application	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.2.3
Ch5, p9	Description of whether distributor is a host and/or embedded distributor; identification of any embedded and/or host distributors; partially embedded status identified (including % of total load supplied through host); if host distributor, identification of whether there is a separate embedded class or if any embedded distributors are included in other classes	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.2.4
Asset Lifestyle Optimization Policies and Practices		
Ch5, p10	Demonstration that distributor has carried out system O&M activities to sustain as asset to the end of its service life (can include references to the Distribution System Code)	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.3
Ch5, p10	Explanation of processes and tools used to forecast, prioritize and optimize system renewal spending and how distributor intends to operate within budget envelopes	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.3.3
Ch5, p10	Demonstration of consideration of potential risks of proceeding/not proceeding with individual capital expenditures	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.3.3.5
Ch5, p10	Summary of important changes to the distributor's asset life optimization policies and processes since last DSP	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.3.4
System Capability Assessment for REG		
Ch5, p10	If a distributor has costs to accommodate and connect renewable generation facilities that will be the responsibility of the distributor under the DSC, refer to Appendix A	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.4
CDM Activities to Address System Needs		
Ch5, p10	Description of how distributor has taken CDM into consideration in its planning process	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.5
Ch5, p11	Any application for CDM funding to address system needs must include a consideration of the projected effects to the distribution system on a long-term basis and the forecast expenditures.	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.5
Ch5, p11	Explanation of proposed activity in the context of the DSP or explanation of any changes to system plans that are pertinent to the activity	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.5
Capital Expenditure Summary		
Ch5, p11	Provide capital expenditure plan that sets out proposed expenditures on distribution system and general plant over a five-year planning period, including investment and asset-related operating and maintenance expenditures	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4
Ch5, p11	Provide a snapshot of a distributor's capital expenditures over a 10-year period, including five historical years and five forecast years	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.1
Ch5, p11	The entire cost of individual projects or programs allocated to one of the four investment categories based on the primary driver of the investment	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.1.2
Ch5, p11	Completed Appendices 2-AA and 2-AB	Filed with Chapter 2 Appendices
Ch5, p11	Analysis of distributor's capital expenditure performance for the DSPs historical period - should include explanation of variances by investment category, including actuals v. OEB-approved amounts for the applicant's last OEB-approved CoS or Custom IR application and DSP - explanation of variances that are much higher or lower than the historical trend	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.1.1
Ch5, pp12	Analysis of distributor's capital expenditure performance for the DSPs forecast period; for investments that have a lifecycle >1yr, the proposed accounting treatment, including the treatment of the cost of funds for CWIP	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.1.2
Ch5, p12	Analysis of capital expenditures in DSP forecast period v. historical	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.1.3
Ch5, p12	Description of the impacts of capital expenditures on O&M for each year or statement that the capital plans did not impact O&M costs	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.1.4
Ch5, p12	Statement that there are no expenditures for non-distribution activities in the applicant's budget	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.1.5
Justifying Capital Expenditures		
Ch5, p12	Context on how overall capital expenditures over 5 years will achieve distributor's objectives; comment on lumpy investment years and rate impacts of capital investments in long term	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.2
Material Investments		
For each project that meets materiality threshold set in Ch 2A or deemed by applicant to be distinct for any other reason, guidelines are:		Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan
Ch5, p13	General information on the project/program - Need, scope, key project timings (incl. key factors that affect timing), total expenditures (inc. contributions and economic evaluation as per DSC, as applicable), comparative historical expenditures, priority, alternatives considered, cost/benefit of recommended alternative, description of the innovative nature of investment if applicable. -Where an investment within the five year forecast period involves a Leave to Construct approval, provide summary of the evidence (as available), for that investment consistent with Chapter 4 of the filing requirements	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.2.1; Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Appendix A
Ch5, p13	Evaluation criteria and information requirements for each project/program - Demonstration of need, and may include the need to address safety, cyber security, grid innovation, environmental, statutory/regulatory obligations - Where investment substantially exceeds materiality - business case justifying expenditure, alternatives (including CDM activities if applicable), benefits for customers, impact on distributor costs -If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.2.1; Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Appendix A
Ch5, p14	Explanation of how innovative project is expected to benefit customers, such as improved reliability, enhanced customer services, CDM, 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	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.4.2.1; Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Appendix A

Appendix A (if applicable)		
Ch5, Appendix A	Information on the capability of distribution system to accommodate REG, including a summary of the distributor's load and renewable energy generation connection forecast by feeder/substation (where applicable); and information identifying specific network locations where constraints are expected to emerge due to forecast changes in load and/or connected renewable generation capacity	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.4
Ch5, Appendix A	In relation to renewable or other distributed energy generation connections, the information that must be considered by a distributor and documented in an application (where applicable), includes: applications from renewable generators > 10 kW, number and MW of REG connections for forecast period, information from IESO and any other information about the potential for renewable generation in distributor's service area, capacity of Dx to connect REG, connection constraints	Exhibit 2, Appendix C: PUC Distribution Inc. Distribution System Plan, Section 5.3.4
EXHIBIT 3 - CUSTOMER AND LOAD FORECAST		
Load Forecasts		
23	Weather normal load forecast provided	Live Excel Model "PUC_2023_Load forecast - With Regression Analysis_20220831"
23	Table outlining any factors that influence the load forecast in distributor's service territory (e.g. demographics, customer composition etc.)	N/A, PUC does not have any factors that influence the load forecast in its service territory.
23	Explanation of the causes, assumptions and adjustments for the volume forecast, including all economic assumptions and data sources used (e.g. housing outlook & forecasts, other variables used in forecasting volumes)	Exhibit 3, Section 3.1: COVID Findings in Regression Analysis
23	Explanation of weather normalization methodology	Exhibit 3, Section 3.1.2 Multivariate Regression Model
23	Completed Appendix 2-IB; the customer and load forecast for the test year entered on RRWF, Tab 10	Live Excel Model "PUC_2023_Chapter 2 Appendices" and "PUC_2023_Revenue Requirement Workform_20220831"
23 & 24	Multivariate Regression Model -rationale to support change if the proposed model's methodology differs from the methodology used in the most recent load forecast; discussion of modelling approaches considered and alternative models tested -statistics of the regression equations coefficients and intercepts (e.g. t-stats, model statistics including R2, adjusted R2, F-stat, root-mean-squared-error), including explanation for any resulting non-intuitive relationships -explanation of weather normalization methodology (including if monthly HDD and/or CDD used they are based on either: 10 year avg. or proposed alternative approach with supporting evidence -definitions of HDD and CDD including: climatological measurement points and why appropriate as well as identification of base degrees -sources of data for endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable data used and source. Where a distributor has constructed the demand variable to model billed consumption on a class-specific basis, a full explanation of the approach used to pro-rate or interpolate non-interval data (i.e. if billing data are not based on calendar monthly readings as obtained from interval or smart meters) must be provided, including an explanation of why the constructed demand series is suitable for modelling -any binary variables used must be explained and justified - the use of binary variables should be limited and overlap with other variables should be avoided -explanation of any specific adjustments made (e.g. to adjust for loss or gain of major customers or load, significant re-classifications of customers, etc.). Note locally purchased generation should be included in the total -description of how CDM impacts and other exogenous factors have been accounted for in the historical period, and how CDM impacts, including any CDM targets or forecasts in the bridge and test years, are factored into the test year load forecast -data and regression model and statistics used in customer and load forecast in Excel format	Exhibit 3, Section 3.1.2 Multivariate Regression Model
25	NAC Model -rationale to support NAC methodology if the model use differs from the method used in the most recent load forecast -data supporting calculation of NAC values for each rate class -description of how CDM impacts and other exogenous factors have been accounted for in historical period and how CDM impacts, including any CDM targets or forecasts in the bridge and test years, are factored into test year forecast -discussion of weather normalization considerations	N/A, Exhibit 3, Section 3.1.3, PUC does not use the NAC Model
Incorporating CDM Impacts in the Load Forecast for Distributors		
25 & 26	Distributor may request approval for the use of the LRAMVA for a new CDM activity (a distribution-rate funded CDM activity or the Local Initiatives Program (LIP)), which would require establishing an LRAMVA threshold. If a distributor does request to establish an LRAMVA threshold, documentation of the CDM savings to be used as the basis for the 2023 LRAMVA threshold, and description of how these savings are aligned with the 2023 load forecast	Exhibit 3, Section 3.1.4: CDM Adjustment
26	If proposing different savings values for a CDM activity in the load forecast and LRAMVA threshold, description of rationale for these differences (e.g., timing of CDM activity, line loss factor, net-to-gross conversion factor)	Exhibit 3, Section 3.1.4: CDM Adjustment
Accuracy of Load Forecast and Variance Analyses		
26	Completed Appendix 2-IB (2-IA provides further instructions for filling out 2-IB)	Live Excel Model "PUC_2023_Chapter 2 Appendices"
26	For customer/connection counts: -identification as to whether customer/connection count is shown in year end or average format -year-over-year variances in changes of customer/connection counts with explanation for changes in the definition of, or major changes made in the composition of each customer class -explanations of bridge and test year forecasts by rate class -for last rebasing, variance analysis between last OEB-approved and actuals with explanations for material differences	Exhibit 3, Section 3.2: Accuracy of Load forecast and Variance Analysis
26 & 27	For consumption and demand: -explanation and details to support how kWh are converted to kW for applicable demand-billed classes -year-over-year variances in consumption (kWh) and demand (kW or kVA - the latter for demand billed rate classes) by rate class and for system consumption overall (kWh) with explanations for material changes in the definition of or major changes over time (comparison done for both historical actuals against each other and historical weather-normalized actuals over time) -explanations of the bridge and test year forecasts by rate class (and how these vary from or are trending from both historical actuals and from weather-normalized actuals) -for last rebasing variance analysis between the last OEB-approved and the actual results with explanations for material differences	Exhibit 3, Section 3.1.2: Subsection: Billed kW Load Forecast
27	All data and equations used to determine customers/connections, demand and load forecasts provided in Excel format	Live Excel Model "PUC_2023_Load forecast - With Regression Analysis_20220831"
Exhibit 4, Section 4 - OPERATING EXPENSES		
Overview		
27	Brief explanation (quantitative and qualitative) of test year OM&A levels, how the distributor develops and receives approval of their OM&A budget, cost drivers and significant changes relative to historical and bridge years, trends in costs and relevant metrics including OM&A per customer (and its components) for the historical, bridge and test years, inflation rate assumed (if proposing different rate than IPI - provide explanation supporting proposal), business environment changes	Exhibit 4, Section 4.1 Overview
OM&A Summary and Cost Driver Tables		
Inclusion of the following tables in evidence and all OM&A appendices filed:		
27	Summary of recoverable OM&A expenses; Appendix 2-JA	Exhibit 4, Section 4.2 Table 4-6, Live Excel Model "PUC_2023_Chapter 2 Appendices"
27	Recoverable OM&A cost drivers; Appendix 2-JB	Exhibit 4, Section 4.2 Table 4-7, Live Excel Model "PUC_2023_Chapter 2 Appendices"
27	OM&A programs table - Appendix 2-JC **or** OM&A by USoA Table - Appendix 2-JD	Exhibit 4, Section 4.3 Table 4-9, Live Excel Model "PUC_2023_Chapter 2 Appendices"
28	Recoverable OM&A Cost per customer and per FTE; Appendix 2-L	
28	Distributors with 30k or more customers: present OM&A by program; Appendix 2-JC filed to provide OM&A details and variance analysis on a program basis. For each program, provide a definition of the USoA accounts included	Exhibit 4, Section 4.3, Live Excel Model "PUC_2023_Chapter 2 Appendices"
28	Distributors with less than 30k customers: option to file OM&A by program or USoA. If USoA chosen, 2-JD filed	N/A
28	The table provided (2-JC or 2-JD) must reflect the entire OM&A amount proposed to be recovered through rates. Information provided for bridge and test years.	Exhibit 4, Section 4.3 Table 4-9, Live Excel Model "PUC_2023_Chapter 2 Appendices"
28	Appendix 2-JB populated to provide information on the cost drivers of OM&A expenses; 2-JA broken down into major categories	Exhibit 4, Section 4.2 Table 4-6, Table 4-7, Live Excel Model "PUC_2023_Chapter 2 Appendices"
28	Identification of change in OM&A in test year in relation to change in capitalized overhead	Exhibit 4, Section 4.3 Table 4-10
OM&A Variance Analysis		
28	Re: 2-JC or 2-JD - variance analysis between: -test year vs last OEB approved -historical OEB-approved vs historical actuals (for the most recent historical OEB-approved year) -test year vs bridge year	Exhibit 4, Section 4.3 Table 4-9, Live Excel Model "PUC_2023_Chapter 2 Appendices"
28 & 29	If OM&A expense detailed on USoA basis, variance analysis and explanation broken down by the five major OM&A categories as per 2-JA	Exhibit 4, Section 4.2 Table 4-6, Live Excel Model "PUC_2023_Chapter 2 Appendices"
29	Variance analysis includes explanation of whether the change was within the distributor's control or not - distributors encouraged to provide explanations for costs above the threshold which have impacted historical trend	Exhibit 4, Section 4.3 OM&A Variance, pg. 25
Workforce Planning and Employee Compensation		
29	Completed Appendix 2-K; information on labour and compensation includes total amount, whether expensed or capitalized	Exhibit 4, Section 4.3.1.3 Table 4-15, Live Excel Model "PUC_2023_Chapter 2 Appendices"
29	If there are three or fewer employees in any category, aggregate with the category to which it is most closely related. This higher level of aggregation must be continued, if required, to ensure that no category contains three or fewer employees.	Complete
29	Description of proposed workforce plans, including compensation strategy and any changes from previous plan	Exhibit 4, Section 4.3.2
29	Discussion of the outcomes of previous plans and how those outcomes have impacted their proposed plans including an explanation of the reasons for all material changes to FTEs and compensation. Explanation for all years includes: - Variances with an explanation of contributing factors, inflation rates used for forecasts, and the plan for any new employees - basis for performance pay, eligible employee groups, goals, measures, and review process for pay-for-performance plans - relevant studies (e.g. compensation benchmarking)	Exhibit 4, Section 4.3.2
29	Details of employee benefit programs including pensions, OPEBs, and other costs charged to OM&A. A breakdown of the pension and OPEBs amounts included in OM&A and capital provided for the last OEB-approved rebasing application, and for historical, bridge and test years	Exhibit 4, Section 4.3.2
29	Most recent actuarial report; tax section of evidence agrees with this analysis	Exhibit 4, Section 4.3.2
29 & 30	For virtual utilities - Appendix K completed in relation to the employees of the affiliates who are doing the work of the regulated utility. Provide the status of pension funding and all assumptions used in the analysis	Exhibit 4, Section 4.3.2
30	Indication if pension and OPEBs to be recovered using cash or accrual method; if cash method, sufficient supporting rationale and evidence for adopting cash method. If proposing to change the basis in which pension and OPEB costs are included in OM&A from last rebasing, quantification of impact of transition provided	Exhibit 4, Section 4.3.2

Shared Services and Corporate Cost Allocation			
	30	Identification of all shared services among affiliates; identification of the extent to which the applicant is a "virtual utility" and justification of proposed shared services and cost allocation	Exhibit 4, Section 4.3.3
	30	For shared services among affiliated entities: type of service provided or received, pricing methodology	Exhibit 4, Section 4.3.3
	30	Allocation methodology for corporate services, list of shared services, list of costs and allocators and how the allocator was derived, any third party review of cost allocation methodology	Exhibit 4, Section 4.3.3, Appendix B
	30 & 31	Completed Appendix 2-N for service provided or received for historical actuals, bridge and test; including reconciliation with revenue included in Other Revenue	Exhibit 4, Section 4.3.3, Live Excel Model "PUC_2023_Chapter 2 Appendices"
	31	Shared Service and Corporate Cost Variance analysis - test year vs last OEB approved and test year vs most recent actual	Exhibit 4, Section 4.3.3
	31	Identification of any Board of Director costs for affiliates included in LDC costs	Exhibit 4, Section 4.3.3
Non-Affiliate Services, One-Time Costs, Regulatory Costs			
	31	Purchases of Non-Affiliated Services - copy of procurement policy (including information on signing authority, tendering process, non-affiliate service purchase compliance)	Exhibit 4, Section 4.3.4
	31	For material transactions not in compliance with procurement policy, or that were undertaken pursuant to exceptions contemplated within the policy, an explanation as to why as well as a summary of the nature and cost of the product, and a description of the specific methodology used for selecting the vendor	
	31	Identification of one-time costs in historical, bridge, test; explanation of cost recovery in test year. If no recovery of one-time costs is being proposed in the test year and subsequent IRM term, an explanation must be provided	Exhibit 4, Section 4.3.4
	32	Regulatory costs - breakdown of actual and anticipated regulatory costs including OEB cost assessments and expenses related to the CoS application (e.g. legal fees, consultant fees), information supporting incremental level of costs for preparation and review of current application, proposed recovery (i.e. amortized?), explanation if different than 5 years, completed Appendix 2-M	Exhibit 4, Section 4.3.5
LEAP, Charitable and Political Donations			
	32	LEAP - the greater of 0.12% of forecasted service revenue requirement or $2,000 should be included in OM&A and recovered from all rate classes. If proposing LEAP funding higher than 0.12%, details of demographics provided	Exhibit 4, Section 4.3.6, Table 4-24
	32	For any charitable contributions claimed for recovery, detailed information provided	N/A, PUC has no other charitable donation other than LEAP
	32	Confirmation that no political contributions have been included for recovery	Exhibit 4, Section 4.3.7
Conservation and Demand Management			
	33	Statement confirming that no costs for dedicated CDM staff to support IESO programs funded under the 2021-2024 CDM Framework are included in the revenue requirement	Exhibit 4, Section 4.4
	33	If distributor plans to partner with the IESO for the LIP at the time of its cost of service application, description of proposed approach to partnership, including a forecast of LIP costs	N/A
Funding Options for Future Conservation and Demand Management Activities			
	33	If CDM activities included in COS where CDM activities expected to come into service during Price Cap IR term, identification of if costs of such CDM activities included in the revenue requirement, or if the distributor intends to propose treatment similar to an ACM for these future CDM activities	N/A
	33	If the latter as noted above, supporting rationale provided (e.g., the preliminary cost information and ACM/ICM materiality threshold calculations to show that a similar capital project would qualify for ACM treatment based on the forecasted information at the time of the DSP and cost of service application)	N/A
EXHIBIT 5 - COST OF CAPITAL AND CAPITAL STRUCTURE			
Capital Structure			
	34	Use of most recent parameters issued by the OEB, subject to update if new parameters available prior to OEB decision. Alternatively - utility specific cost of capital with supporting evidence and justification	Exhibit 5, Section 5.2 Cost of Capital
	34	Completed Appendix 2-OA for last OEB approved and test years	Exhibit 5, Section 5.2.3 Capital Structure and Cost of Capital
	34	Completed Appendix 2-OB for historical, bridge and test years	Exhibit 5, Section 5.2.4 Weighted Average Cost of Long Term Debt
	34	Explanation for any material changes in capital structure or material differences between actual and deemed capital structure including: retirement of debt or preference shares and buy-back of common shares; short-term debt, long-term debt, preference shares and common share offerings	N/A, there are no material changes in capital structure or material difference between actual and deemed capital structure.
Cost of Capital (Return on Equity and Cost of Debt)			
	The following provided for each year:		
	34	Calculation of cost for each capital component	Exhibit 5, Section 5 Capital Structure and Cost of Capital Appendix 2-OA
	34	Profit or loss on redemption of debt, if applicable	N/A
	35	Copies of current promissory notes or other debt arrangements with affiliates	Exhibit 5, Appendix 1
	35	Explanation of debt rate for each existing debt instrument including an explanation on how the debt rate was determined and is in compliance with the policies documented in the 2009 Report or applicant's proposed approach	Exhibit 5, Section 5.2.2 Cost of Debt: Long Term
	35	Forecast of new debt in bridge and test year - details including estimate of rate and other pertinent information (e.g. affiliated debt or third party?)	Exhibit 5, Section 5.2.2 Cost of Debt: Long Term for Loan #6 and Loan #7
	35	If proposing any rate that is different from the OEB guidelines, a justification of the proposed rate(s), including key assumptions	Exhibit 5, Section 5.2.2 Cost of Debt: Long Term Explains OEB Cost of Capital Parameters used for Affiliate debt (Promissory Note)
	35	Historic return on equity achieved	Exhibit 5, Section 5.2.6 Historical Return on Equity
Not-for-Profit Corporations			
	35	Requested capital structure and cost of capital (including the proposed cost of long-term and short-term debt and proposed return on equity)	N/A, PUC is a For Profit Corporation.
	35	Statement as to whether the revenues derived from the return on equity component of the cost of capital is to be used to fund reserves or will be used for other purposes	
	35	If the revenues derived from the return on equity component will be used to fund reserves, specifications for each proposed reserve fund and a description of the governance (policies, procedures, sign-off authority, etc.) that will be applied	
	35 & 36	If the revenues derived from the return on equity component will be used for other purposes, statement as to whether these revenues will be used for non-distribution activities (in the situation where the excess revenues are greater than the amounts needed to fund distribution activities); rationale provided supporting the use of the revenues in this manner. Also, governance (policies, procedures, sign-off authority, etc.) that will be applied to the funding of non-distribution activities provided	
	36	If there are approved reserves from previous OEB decisions provide the following: -the limits of any capital and/or operating reserves as approved by the OEB, and identifying the decisions establishing these reserve accounts and their limits -the current balances of any established capital and/or operating reserves	
EXHIBIT 6 - REVENUE REQUIREMENT AND REVENUE DEFICIENCY OR SUFFICIENCY			
	36	The following information must be provided in this exhibit (with cross references to where in the application further details can be found for each): -determination of net utility income, statement of rate base, actual return on rate base, indicated rate of return, requested rate of return, deficiency or sufficiency in revenue, gross deficiency or sufficiency in revenue	Exhibit 6 Revenue Requirement Table 6-1
	36	Revenue deficiency or sufficiency calculations net of electricity price differentials captured in the Retail Settlement Variance Accounts (RSVAs) and also net of any cost associated with low voltage (LV) charges or DVA balances of distribution expenditures/revenues being tracked through approved deferral and variance accounts for certain distribution assets (e.g. ICM and ACM capital projects, MIST meters) and for which disposition is not being sought in the application.	Exhibit 6 Calculation of Revenue Deficiency/Sufficiency
	36	Summary of drivers for test year deficiency/sufficiency, how much each driver contributes; references in application evidence mapped to drivers	Exhibit 6 Cost Drivers on Revenue Deficiency
	37	Impacts of any changes in methodologies on deficiency/sufficiency and on individual cost drivers contributing to it	N/A, no changes in methodologies
Revenue Requirement Work Form			
	37	Completed RRWF. Revenue requirement, def/sufficiency, data entered in RRWF must correspond with other exhibits	Exhibit 6, Appendix A
	37	If the enhanced RRWF cannot reflect a distributor's proposed rates accurately, the distributor must file its rate generator model	N/A, RRWF is able to reflect rates accurately.
	37	For revenues - calculation of bridge year forecast of revenues at existing rates; calculation of test year forecasted revenues at each of existing rates and proposed rates	Exhibit 6, Table 6-8
Income Tax or PILs			
	38	Detailed calculations of income tax or PILs as applicable. Completed version of the PILs model; derivation of adjustments for historical, bridge, test years	Exhibit 6, Section 6.2
	38	Supporting schedules and calculations identifying reconciling items	Exhibit 6, Section 6.2
	38	Most recent federal and provincial tax returns	Exhibit 6, Appendix B
	38	Financial Statements included with tax returns if different from those filed with application	Exhibit 6, Appendix B
	38	Calculation of tax credits; redact where required (filing of unredacted versions is not required)	Exhibit 6, Section 6.2
	38	Supporting schedules, calculations and explanations for other additions and deductions	Exhibit 6, Section 6.2
	38	Completion of the integrity checks in the PILs Model	Exhibit 6, Section 6.2
	39	Accelerated CCA - full revenue requirement impact recorded in Account 1592 and the balance sought for review and disposition, method used in calculating the revenue requirement impact recorded in Account 1592, detailed calculations by year for the full revenue requirement impact recorded in Account 1592	Exhibit 6, Section 6.2
	39 & 40	**May** propose smoothing mechanism proposal	Exhibit 6, Section 6.2
Other Taxes			
	40	Excluded from all OM&A totals. Explanation of how these tax amounts are derived	Exhibit 6, Section 6.2
Non-recoverable and Disallowed Expenses			
	40	Exclude from regulatory tax calculation any non-recoverable or disallowed expenses	N/A, PUC does not have any non-recoverable or disallowed expenses.
Other Revenue			
	40	Completed Appendix 2-H, including the breakdown of each account showing the components of each	Exhibit 6, Section 6.3.1
	40	For each other distribution revenue account: -comparison of actual revenues for historical years to forecast revenue for bridge and test year, including explanations for significant variances year-over-year -revenue from any new proposed specific service charges, changes to rates, or new rules for applying existing specific service charges (incl. any credits to customers) -revenue from affiliate transactions, shared services, or corporate cost allocation. For each affiliate transaction identification of service, the nature of service provided, accounts used to record revenue, and costs to provide service -revenue from affiliate transactions recorded in Account 4375 -expenses from affiliate transactions recorded in Account 4380	Exhibit 6, Section 6.3.1
	41	Balances recorded in Account 4375 and Account 4380 reconcile to the balances recorded in Appendix 2-N – Shared Services and Corporate Allocation for the three historic years, the bridge year and the test year. Any differences must be reconciled	Exhibit 6, Section 6.3.1
	41	Revenue related to microFIT recorded as revenue offset in Account 4235 and not included as part of base revenue requirement	Exhibit 6, Section 6.3.1
	41	Transfer pricing and allocation of cost methods do not result in cross-subsidization between regulated and non-regulated lines of business and compliance with article 340 of APH; explanations for any deviations	Exhibit 6, Section 6.3.1
	41	Identification of any discrete customer groups that may be materially impacted by changes to other rates and charges.	Exhibit 6, Section 6.3.1

EXHIBIT 7 - COST ALLOCATION		
Cost Allocation Study Requirements		
42	Completed cost allocation study using the OEB-approved methodology or the distributor's study and model reflecting forecasted test year loads and costs and supported by appropriate explanations and live Excel spreadsheets; sheets 11 and 13 of the RRWF complete	Live Excel Models "PUC_2023_Cost Allocation Model_20220831" and "PUC_2023_Rev_reqt_workform_20220831"
42	Description of weighting factors, rationale for use of default values (if applicable)	Exhibit 7, Section 7.1.1 Weight Factors, 7.1.2 Services and 7.1.3 Billing and Collection
42	If distributor is choosing to use the same weightings as its previous rebasing application, a reference to the previous application provided	Exhibit 7, Section 7.1.1 Weight Factors, 7.1.2 Services and 7.1.3 Billing and Collection
42	Complete live Excel cost allocation model, whether using the OEB-issued one or a different model. If using the OEB-issued model, Input sheet I.2, cells c15 and c17 must be used to identify the final run of the model on each sheet. If using another model, the distributor must file equivalent information.	OEB's Cost allocation model was used and has been filed in the Live Excel format.
Load Profiles and Demand Allocators		
43	Updated all classes' load profiles and updated demand allocators	Exhibit 7, Section 7.1.7 Load Profiles and Demand Allocations and 7.1.7.1 Demand Profile Methodology
43	Discussion of how load profiles have been normalized for weather and any notable events impacting usage patterns	Exhibit 7, Section 7.1.7 Load Profiles and Demand Allocations and 7.1.7.1 Demand Profile Methodology
43	If multivariate regression used, the following provided: -statistics of regression equation(s) coefficients and intercept -explanation of the weather-normalization methodology including: relationship between demand and Heating and/or Cooling requirements, determination of normal weather: the hourly for daily Heating and/or Cooling required -sources of data used for both endogenous and exogenous variables. Where a variable has been constructed, explanation of the variable, data used and the source of the data provided -explanation of any specific adjustments made (e.g. to address gaps in historical meter data)	Exhibit 7, Section 7.1.7 Load Profiles and Demand Allocations and 7.1.7.1 Demand Profile Methodology
43	Data and regression model and statistics used in customer and load forecast provided in Excel format (includes showing the derivation of any constructed variables)	Exhibit 7, Section 7.1.7 Load Profiles and Demand Allocations and 7.1.7.1 Demand Profile Methodology
44	Demand Allocators: spreadsheet and a description with calculations to show how demand allocators are derived from the historical weather normal or weather actual load profiles	Exhibit 7, Section 7.1.7 Load Profiles and Demand Allocations and 7.1.7.1 Demand Profile Methodology
44	Historical Average: Where the annual demand allocators are based on weather actual load profiles, at least three, and ideally five years of historical data should be used to perform weather normalization. Where the annual demand allocators are based on weather normalized load profiles, fewer years may be used	Exhibit 7, Section 7.1.7 Load Profiles and Demand Allocations and 7.1.7.1 Demand Profile Methodology
44 & 45	Host Distributor only - evidence of consultation with embedded Dx - statement regarding embedded Dx support for approach to allocation of costs - if embedded Dx is separate class - class in cost allocation study and RRWF - if new embedded Dx class - rationale and supporting evidence (cost of serving, load served, asset ownership information, distribution charges levied); include in cost allocation study and RRWF - if embedded Dx billed as GS customer - include with the GS class in cost allocation model and the RRWF. Provide cost of serving, load served, asset ownership information, distribution charges levied, appropriateness of rates for the GS class recovering costs of providing low voltage dx services to embedded distributor(s). Completed Appendix 2-Q.	N/A
45	microFIT - if the applicant believes that it has unique circumstances which would justify a different rate than the generic rate, documentation to support rate must be provided	PUC has used the generic rate
46	Standby Rates - distributors should request approval for its standby rates to be made final and provide evidence confirming that they have advised all affected customers of the proposal. A distributor that seeks changes to its standby charges, including a change in the methodology on which these rates are based, must provide full documentation supporting its proposal, and confirm that all affected customers have been notified of the proposed change(s).	N/A, PUC does not charge Standby Rates.
46	If new customer class or changing definition of existing classes, rationale and restatement of revenue requirement from previous cost of service	N/A, no changes to customer classes.
46	If eliminating or combining customer classes, rationale and restatement of revenue requirement from previous cost of service	N/A, PUC is not eliminating or combining customer classes.
Class Revenue Requirements		
46 & 47	To support a proposal to rebalance rates, information on the revenue by class that would apply if all rates were changed by a uniform percentage provided. Ratios compared with the ratios that will result from the rates being proposed by the distributor.	Exhibit 7, Section 7.2 Class Revenue Requirements
Revenue to Cost Ratios		
47 & 48	If R:C ratios outside dead band - cost allocation proposal to bring them within the OEB-approved ranges provided. In making any such adjustments, potential mitigation measures addressed if the impact of the adjustments on the rates of any particular class or classes is significant.	Exhibit 7.3 Revenue-to-Cost Ratios
48	If distributor proposes to continue rebalancing rates after the cost of service test year, the ratios proposed for subsequent year(s) must be provided	
48	If Cost Allocation Model other than OEB model used - exclude LV, exclude DVA such as smart meters	
EXHIBIT 8 - RATE DESIGN		
48	Monthly fixed charges - 2 decimal places; variable charges - 4 decimal places; if departing from this approach, explanation provided as to why necessary and appropriate	PUC has not departed from this approach.
Fixed Variable Proportion		
48	The following is to be provided in relation to the fixed/variable proportion of proposed rates: -Current F/V for each rate class with supporting info -Proposed F/V for each rate class with explanation for any changes from current proportions -Table comparing current and proposed monthly fixed charges with the floor and ceiling as in cost allocation study Analysis must be net of rate adders, funding adders, and rate riders	Exhibit 8, Section 8.1
RTSRs		Confirmed filed in Live Excel model "PUC_2023_RTSR_Workform_20220831"
49	Completed RTSR Model in Excel	
49	RTSR information consistent with working capital allowance calculation; explanation for any differences	No differences
Retail Service Charges		
49	Distributors that are still using the Retail Service Costs Variance Accounts (RCVAs) or Retail Service Charges Incremental Revenue Sub-account are to dispose of the balances and the OEB will eliminate the sub-accounts. Distributors should forecast retail services revenues based on the updated charges and include the costs of providing retail services in revenue requirement	Exhibit 8, Section 8.3
Regulatory Charges		
50	If applying for a rate other than the generic rate set by the OEB, distributors must provide justification as to why their specific circumstances would warrant a different rate, in addition to a detailed derivation of their proposed rate	Exhibit 8, Section 8.4 puc has used the generic rates set by the OEB.
Specific Service Charges		
50	If requesting new specific service charge or a change to the level of an existing charge, description of the purpose of charge, or reason for change to an existing charge; calculations to support charges	Exhibit 8, Section 8 Section 2.8.5 PUC is not requesting any new specific services charges.
50	Identification in the Application Summary all proposed changes that will have an impact on customers, including changes to other rates and charges that may affect a discrete group; identification of specific customers or customer groups impacted by each proposal	
50	Calculation of charge includes: direct labour, labour rate, burden rate, incidental, other	
51	Identification of any rates and charges in Conditions of Service that do not appear on tariff sheet. Explain nature of costs, provide schedule outlining revenues or capital contributions recovered from these rates from last OEB-approved year to most recent actuals and the revenue or capital contributions forecasted for the bridge and test years. A proposal and explanation as to whether these charges should be included on tariff sheet	
51	Revenue from SSCs corresponds with Operating Revenue evidence	
Wireline Pole Attachment Charge		
51	Distributor disposing of Wireline account may forecast the balance up to the effective date of new rates, provided it can do so with reasonable accuracy, and the OEB may consider disposing of the forecasted amount	Exhibit 8, Section 8.5
Low Voltage Service Rates		N/A, PUC does not charge low voltage rates.
If the distributor is fully or partially embedded, information on the following must be provided:		
52	Forecast LV Cost	
52	Actual LV Cost for the last three historical years along with bridge and test year forecasts; year-over-year variances and explanations for substantive changes in costs over time up to and including test year forecast	
52	Support for forecast LV, e.g. Hydro One Sub-Transmission charges	
52	Allocation of forecasted LV cost to customer classes (typically proportional to Tx connection revenue)	
52	Proposed LV rates by customer class	
Smart Meter Entity Charge		
53	Current OEB-approved SMC charged until the OEB approved any updated SMC	Exhibit 8, Section 8.7
Loss Factors		Exhibit 8, Section 8.8
53	Proposed SFLF and Total Loss Factor for test year	
53	Statement as to whether LDC is embedded including whether fully or partially	
53	Study of losses if required by previous decision	
53	3-5 years of historical loss factor data - Completed Appendix 2-R	
53	If proposed distribution loss factor >5%, explanation for level of losses, details of actions taken to reduce losses in the previous five years, and actions planned to reduce losses going forward	
53	Explanation of SFLF if not standard	
53	Reconciliation between the application and RRR filing	
Tariff of Rates and Charges		
53 & 54	Current and proposed Tariff of Rates and Charges - must be filed in Excel format and PDF format Explanation and support of each change in the appropriate section of the application	Exhibit 8.9 and Appendix 2 and 3 of Exhibit 8. Also filed in Live Excel model, "PUC_2023_Tariff_Schedule_and_Bill_Impact_Model_20220831"
54	Completed Bill Impacts Model	Filed in Live Excel format and attached as Appendix 4 to Exhibit 8
54	Explanation of changes to terms and conditions of service if changes affect application of rates and rationale behind those changes	Exhibit 8, Section 8.9
54	Proposed tariffs must include applicable regulatory charges, and any other generic rates as ordered by the OEB	Exhibit 8, Section 8.9 - Completed
Revenue Reconciliation		
54	Calculations of revenue per class under current and proposed rates; reconciliation of rate class revenue and other revenue to total revenue requirement (i.e. breakout volumes, rates and revenues by rate component etc.)	Exhibit 8, Section 8.9, Table 8-12
54	Completed RRWF - Sheet 13 (table reconciling base revenue requirement against revenues recovered through proposed rates)	
Bill Impact Information		
54	Completed Tariff Schedule and Bill Impacts Model. Bill impacts must identify existing rates, proposed changes to rates, and detailed bill impacts (including % change in distribution excluding pass through costs - Sub-Total A, % change in distribution - Sub-Total B, % change in delivery - Sub-Total C, and $ change in total bill)	Filed in Live Excel Format and in PDF as Appendix 4 to Exhibit 8
54	Impact of changes resulting from the as-filed application on representative samples of end-users (i.e. volume, % rate change and revenue). Commodity and regulatory charges held constant	Exhibit 8 Live Excel file
55	Bill impacts provided for typical customers and consumption levels. Must provide residential 750 kWh and GS<50 2,000 kWh. Bill impacts must be provided for a range of consumption levels relevant to the service territory for each class	Exhibit 8 Live Excel file
55	If applicable, for certain classes where one or more customers have unique consumption and demand patterns, the distributor must show a typical impact and provide an explanation	N/A, no unique consumption patterns.
Rate Mitigation		
55	Mitigation plan if total bill increase for any customer class is >10% including: specification of class and magnitude of increase, description of mitigation measures, justification for mitigation measure including reasons if no mitigation proposed, other relevant information. The Tariff Schedule and Bill Impacts Model must reflect any mitigation plan proposed.	Exhibit 8, Section 8.12
Rate Harmonization Mitigation Issues		N/A, PUC has no rate harmonization issues
56	If part of a MAADs transaction, and rate harmonization plan not yet approved by the OEB, a rate harmonization plan must be filed	
56	Plan includes a detailed explanation and justification for the implementation plan, and an impact analysis	
56	If impact of COS increases and harmonization effects result in total bill increases for any customer class exceeding 10%, discussion of proposed measures to mitigate increases in its mitigation plan, or justification provided as to why mitigation is not required	
56	Migration plan that includes fully harmonizing rates that is to be accomplished over more than one year must be supported by a detailed plan for accomplishing this during the subsequent Price Cap IR period	

EXHIBIT 9 - DEFERRAL AND VARIANCE ACCOUNTS		
56	Table showing all DVAs not disposed of yet, showing principle and interest/carrying charges, total balance for each account, and whether account being proposed for disposition	Exhibit 9, Table 9-2
56	If applicable, description of DVAs that were used differently than as described in the APH, relevant accounting order or other OEB document	N/A
56	Completed DVA continuity schedule for period from last disposition to present - live Excel format. Continuity schedule must show separate itemization of opening balances, annual adjustments, transactions, dispositions, interest and closing balances for all outstanding DVAs. The opening principal amounts and interest amounts for Group 1 and 2 balances, shown in the DVA Continuity Schedule, must reconcile with the last applicable approved closing balances.	Exhibit 9, Section 9.1 paragraph "DVA Continuity Schedule" Live Excel DVA Continuity Schedule spreadsheet submitted
57	Confirmation of use of interest rates established by the OEB by month or by quarter for each year; most recently published rate used for future periods	Exhibit 9, Section 9.4 Interest rates applied
57	Explanation if account balances in continuity schedule differs from trial balance reported through RRR and documented in AFS - included in tab Appendix A of DVA schedule. This includes all Account 1508 sub-accounts. A reconciliation of all the Account 1508 sub-accounts to the Account 1508 control account reported in the RRR is to be provided in the continuity schedule	Exhibit 9, Section 9.2 and Table 9-1
57	Identification of any Group 2 accounts proposed to continue/discontinue going forward, with explanation	Exhibit 9 - Table 9-15
57	Identification of any new accounts or sub-accounts, and justification; must correspond with info in Exhibit 1	Exhibit 9, Section 9.7, Table 9-15, New accounts being requested as per Accounting Orders attached, Appendix B and C
57	Statement whether any adjustments made to DVA balances previously approved by OEB on final basis - the OEB expects that no adjustment will be made to any deferral and variance account balances previously approved by the OEB on a final basis. If any adjustments have been made, explanation for the nature and the amount of the adjustment(s), and appropriate supporting documentation, under a section titled "Adjustments to Deferral and Variance Accounts"	Exhibit 9, Section 9.2
57	Statement confirming distributor has complied with OEB guidance of February 21, 2019 on the accounting for Accounts 1588 and 1589	Exhibit 9, Section 9.5.1.5
Disposition of Deferral and Variance Accounts		
57	For accounts as identified in summary table not being proposed for disposition, explanations provided	Exhibit 9, Section 9.5 - Accounts 1508 ICM
58	For any distributor-specific accounts requested for disposition, supporting evidence showing how the annual balance is derived and the relevant accounting order	Exhibit 9, Section 9.5 - Accounts 1508 ICM - reconciliations in Exhibit 2
58	If proposing to allocate a DVA which the OEB has not established an allocator, proposed allocation based on cost driver must be provided with justification; indication of proposed billing determinants, including charge type for recovery purposes and included in cont. schedule	N/A
58	Propose rate riders that dispose of the balances. If the applicant is proposing an alternative recovery period other than one year, explanation provided	Exhibit 9, Section 9.9
58	Rate riders where volumetric rider is $0.0000 for one or more classes not included in the tariff for those classes	Exhibit 9, Section 9.9
Disposition of Accounts 1588 and 1589		
55	If a distributor has not implemented OEB's February 21, 2019 accounting guidance, indication that this is the case	N/A, PUC implemented the OEB's February 21, 2019 accounting guidance.
55	Indication of the year in which Account 1588 and Account 1589 balances were last approved for disposition, and whether the balances were approved on an interim or final basis. If the balances were last disposed on an interim basis, indicate the year in which balances were last disposed on a final basis	Exhibit 9, Section 9.2
59	If requesting final disposition of balances for the first time following implementation of the accounting guidance, confirmation that accounting guidance has been implemented fully effective January 1, 2019	N/A
59 & 60	In order to request for final disposition of historical balances as part of the current application, confirmation that these balances have been considered in the context of the accounting guidance and provide a summary of the review performed. Discussion on the results of the review, any systemic issues noted, and whether any material adjustments to those balances have been recorded. Summary and description of each adjustment made to the historical balances provided	N/A
60	GA Analysis Workform (in live Excel format) for each year that has not previously been approved by the OEB for disposition. If the distributor is adjusting the Account 1589 GA balance that was previously approved on an interim basis, the GA Analysis Workform must be completed from the year after the distributor last received final disposition for Account 1589	Exhibit 9, Section 9.5.1.6. GA Analysis Workform, Live Excel file "PUC 2023_GA_Analysis_Workform_20220831
60	As described in Note 5 in the GA Analysis Workform, reconciliation of any discrepancy between the actual and expected balance by quantifying differences (e.g. true-ups between estimated and actual costs and/or revenues). Any remaining unexplained discrepancy that is greater than +/- 1% of the total annual IESO GA charges will be considered material and warrant further investigation.	Exhibit 9, Section 9.5.1.6. GA Analysis Workform, Live Excel file "PUC 2023_GA_Analysis_Workform_20220831, is less than +/- 1%of the total annual IESO GA charges.
60	Completed reasonability test for the balance in Account 1588. The reasonability test is included in the GA Analysis Workform.	Exhibit 9, Section 9.5.1.6. GA Analysis Workform, Live Excel file "PUC 2023_GA_Analysis_Workform_20220831
Disposition of CBR Class B Variance		
60 & 61	Proposed disposition of Account 1580 sub-account CBR Class B in accordance with the CBR Accounting Guidance. Must be disposed over one year. - In the DVA continuity schedule, indication whether any Class A customers served during the period where Account 1580 CBR Class B sub-account balance accumulated. In the event that the allocated CBR Class B amount results in a volumetric rate rider that rounds to zero at the fourth decimal place in one or more rate classes, the entire balance in Account 1580 CBR Class B sub-account will be added to the Account 1580 – WMS control account to be disposed through the general purpose Group 1 DVA rate riders - Account 1580 sub-account CBR Class A is not to be disposed through rates proceedings but rather follow the OEB's accounting guidance	Exhibit 9, Section 9.5.1.2, Live Excel "DVA Continuity Schedule" spreadsheet, number of Class A customers remained the same throughout the year, no transitions, no CBR- Class A amount being disposed.
Disposition of Account 1595		
61	Applicants are expected to request disposition of residual balances in Account 1595 Sub-accounts for each vintage year once, on a final basis	Exhibit 9, Section 9.5.1.7., Live Excel file "PUC 2023_1595_Analysis_Workform_20220831"
62	Explanation for any material residual balances being proposed for disposition, including quantifying significant drivers of the residual balance	Exhibit 9, Section 9.5.1.7., Live Excel file "PUC 2023_1595_Analysis_Workform_20220831"
Disposition of Retail Service Charges		
62	If there is a balance in 1518 or 1548, distributor must: - confirm variances are incremental costs of providing retail services; identify drivers for balances - provide schedule identifying all revenues and expenses listed by USoA that are incorporated into the variances - state whether Article 490 of APH has been followed; explanation if not followed	Exhibit 9, Section 9.5.2.4
62 & 63	The OEB established a new variance account for electricity distributors that no longer used the RCVAs. The balance in the account would be refunded to ratepayers in a future rate application, and the new account subsequently closed. Distributors may forecast a balance up to the effective date of new rates and the OEB may consider disposing of the forecasted amount	
Disposition of Account 1592, Sub-account CCA Changes		
63	Calculations for accelerated CCA differences per year, based on actual capital additions. Calculations include: undepreciated capital cost continuity schedules for each year itemized by CCA class, calculated PILs/tax differences, grossed-up PILs/tax differences. other applicable information	Exhibit 9, Section 9.2.5.8
63	Confirmation that Account 1592 amounts related to ICM/ACM have been included in the account, if applicable	
63	Reconciliation of these amounts to the amounts presented in Account 1592 sub-account CCA changes in the DVA continuity schedule	
Disposition of Account 1509 Impacts Arising from the COVID-19 Emergency		
64	If requesting disposition of any amounts related to the COVID-19 Account, the following, at a minimum is to be provided: -Discussion regarding the interactions between the COVID-19 Account and other existing generic or utility-specific accounts, including a determination that there is no double-counting between multiple ratemaking mechanisms -Calculation showing that the distributor passes the ROE-based means tests, including limitations on recoveries when various ROE thresholds are reached, and that the appropriate recovery rates for each sub-account have been applied -Supporting calculations for the annual amounts recorded in each of the sub-accounts, including the methodology used to measure incremental costs and savings, as applicable - Discussion of causation, materiality, prudence of any amounts recorded in the sub-accounts, including all identified savings and cost reductions -Discussion of whether the distributor would be able to reasonably forecast any further entries in the account, up to the effective date of the new rates, so that the account may be disposed in its entirety in the current proceeding (and whether the distributor would be amenable to such an approach) -Statement confirming proposed discontinuation of the COVID-19 Account, effective the same date as the new rates. If this is not the case, supporting rationale provided	Exhibit 9, Section 9.5.2.5
Establishment of New Deferral and Variance Accounts		
64 & 65	If new DVA - evidence provided which demonstrates that the requested DVA meets the following criteria: causation, materiality, prudence; include draft accounting order	Exhibit 9, Section 9.7, Appendix B and C
Lost Revenue Adjustment Mechanism Variance Account		
65	In preparing claims related to disposition of outstanding LRAMVA balances, distributors may seek to claim savings from Conservation First Framework (CFF) programs, and from programs they delivered through the Local Program Fund that was part of the Interim Framework. Distributors should provide sufficient supporting documentation on project savings to support their claim	Exhibit 9, Section 9.5.2.7
Disposition of LRAMVA		Live Excel file "PUC 2023_LRAMVA_Workform_20220831" Live Excel file "PUC_2023_Participation and Cost Report (2019 04)_20220831" Exhibit 4, Section 4.4.1 Exhibit 4, Appendix D, IndEco LRAMVA 2023 report (2022-07-12) Exhibit 9, Section 9.5.2.7
66	Disposition sought of all outstanding LRAMVA balances related to previously established LRAMVA thresholds	
67	Current version of LRAMVA Work Form (Excel)	
An application for lost revenues should include:		
67	Final Verified Annual Reports if claiming lost revenues from savings from CDM programs delivered in 2017 or earlier	
67	Participation and Cost reports and detailed project level savings in Excel format made available by the IESO	
67	Other supporting evidence with an explanation and rationale should be provided to justify the eligibility any other savings from a program delivered by a distributor after April 15, 2019	
67 & 68	Personal information and commercially sensitive information removed, or if required, filed in accordance with OEB's Rules of Practice and Procedure and Practice Direction on Confidential Filings	
An application for lost revenues should also provide:		
68	Statement identifying the year(s) of new lost revenues and prior year savings persistence claimed in the LRAMVA disposition	
68	Statement confirming LRAMVA based on verified savings results supported by the distributors final Verified Annual Reports and Persistence Savings Report (both filed in Excel format)	
68	Statement indicating that the distributor has relied on the most recent input assumptions available at the time of program evaluation	
68	Summary table with principal and carrying charges by rate class and resulting rate riders	
68	Statement confirming recovery period; rationale provided for disposing the balance in the LRAMVA if one or more classes do not generate significant rate riders	
68	Details related to the approved CDM forecast savings from the last rebasing application	
69	Statement explaining how rate class allocations for actual CDM savings were determined by class and program for each year	
69	Statement confirming whether additional documentation was provided in support of projects that were not included in distributors final Verified Annual Reports and Participation and Cost Reports (Tab 8 of LRAMVA Work Form as applicable)	
69	If not already filed in support of a previous LRAMVA application, provide Participation and Cost Reports and detailed project level savings files made available by the IESO and/or other supporting evidence to support the clearance of energy- and/or demand-related LRAMVA balances where final verified results from the IESO are not available - filed in Excel format	
69	For a distributor's street lighting project(s) which may have been completed in collaboration with local municipalities, the following must be provided: explanation of the methodology to calculate street lighting savings, confirmation whether the street lighting projects received funding from the IESO and the appropriate net-to-gross assumption used to calculate streetlighting savings	
For the recovery of lost revenues related to demand savings from street light upgrades, distributors should provide the following information:		
69	Explanation of the forecast demand savings from street lights, including assumptions built into the load forecast from the last CoS application	
69	Confirmation that the street light upgrades represent incremental savings attributable to participation in the IESO program, and that any savings not attributable to the IESO program have been removed	
69	Confirmation that the associated energy savings from the applicable IESO program have been removed from the LRAMVA workform so as not to double count savings	
69	Confirmation that the distributor has received reports from the participating municipality that validate the number and type of bulbs replaced or retrofitted through the IESO program	
69 & 70	A table, in live Excel format, that shows the monthly breakdown of billed demand over the period of the street light upgrade project, and the detailed calculations of the change in billed demand due to the street light upgrade project (including data on number of bulbs, type of bulb replaced or retrofitted, average demand per bulb)	
For the recovery of lost revenues related to demand savings from other programs that are not included in the monthly Participation and Cost Reports of the IESO (for example Combined Heat and Power projects), distributors should provide the following information:		
70	The third party evaluation report that describes the methodology to calculate the demand savings achieved for the program year. In particular, if the proposed methodology is different than the evaluation approaches used by the IESO, an explanation must be provided explaining why the proposed approach is more appropriate	
70	Rationale for net-to-gross assumptions used	
70	Breakdown of billed demand and detailed level calculations in live Excel format	
For program savings up to December 31, 2022 for projects completed after April 15, 2019, a distributor should provide the following:		
70	Related to CFF programs: explanation as to how savings have been estimated based on the available data (i.e., IESO's Participation and Cost Reports) and/or rationale to justify the eligibility of the program savings	
70	Related to programs delivered by a distributor through the Local Program Fund under the Interim CDM Framework: explanation and rationale to justify the eligibility of the additional program savings	
Continuing Use of the LRAMVA for New CDM Activities		
70	Indication of whether distributor is requesting the continued use of the LRAMVA for one or more activities related to distribution rate-funded CDM activities or LIP activities	Exhibit 9, Section 9 Section 9.5.2.7
70	If requesting access to, or use of, the LRAMVA for these activities, demonstration of need for the LRAMVA (or similar mechanism), the proposed LRAMVA threshold, how it intends to support the tracking of lost revenues, and the nature of the documentation that it proposes to provide at the time of LRAMVA disposition	N/A
70 & 71	Allocation of the CDM savings for both the LRAMVA and the load forecast provided by customer class and for both kWh and, as applicable to a customer class, kW. Document how CDM savings will be tracked and reported in order to account for differences between forecast revenue loss attributable to CDM activity embedded in rates and actual revenue loss due to the impacts of CDM programs	N/A
Appendix A Cost of Eligible Investments for the Connection of Qualifying Generation Facilities		
Appendix A	If applicable, proposal to divide the costs of eligible investments between the distributor's ratepayers and all Ontario ratepayers per O.Reg. 330/09	N/A
Appendix A	Appendices 2-FA through 2-FC identifying all eligible investments for recovery	N/A
Appendix A	For distributors that are already receiving rate protection as a result of a previous application the new (current) cost of service application should include an update to include the actual costs incurred for the investments as well as a depreciation adjustment to calculate a new capital amount for input into Appendices 2-FA through 2-FC. This would generate a new up-to-date rate protection amount for the test year and beyond, which will be subject to the materiality threshold	N/A

APPENDIX B

PUC Distribution's

5 Year Business

Plan

Five Year Business Plan

2023 Budget and 2024-2027 Projections

August 2022

www.ssmpuc.com

Table of Contents

1. Executive Summary

PUC Distribution Inc. ("PUC") has developed this business plan to address the expectations of the Ontario Energy Board ("OEB")'s "Handbook for Utility Rate Applications," issued October 13, 2016. It outlines how key challenges associated with PUC's service areas, PUC's core values, and the preferences of PUC's customers have been integrated into its Cost-of-Service Rate Application ("COS") and Distribution System Plan ("DSP") in a manner that is consistent with the outcomes of the OEB's Renewed Regulatory Framework ("RRF"). This business plan also summarizes PUC's target and forecasted performance with respect to performance metrics to ensure that PUC delivers its strategic objectives.

PUC's vision is to improve communities through curiosity and innovation. Today more than ever, PUC's focus is on a sustainable company which is developing strategies to lower its carbon footprint, support communities, and offer excellent customer service.

This 2023-2027 business plan is reflective of that vision, as it balances reliability and affordability for customers and allows PUC to invest in the communities it serves.

All costs and projected revenues have been closely examined and reasonable assumptions respecting growth and expected OEB rate increases have been used. PUC's five (5) year financial projections are provided in Appendix A.

The OEB's framework will continue to challenge PUC's management and staff to find operational savings and efficiencies throughout the organization to achieve reasonable financial results. Although a capital replacement plan is in place, ongoing monitoring of cash flow levels and updated asset condition assessments will necessitate constantly reviewing the plan as more information becomes available to balance sustainability and affordability.

Management remains confident that with a successful outcome to the COS, the financial challenges will not hinder PUC's goals of exceeding the service quality indicators as detailed on the local distribution company ("LDC") scorecard, improving customer communication and advocacy, replacing infrastructure in an effective and prudent manner, maintaining rates at a reasonable level, and providing a return to the shareholder.

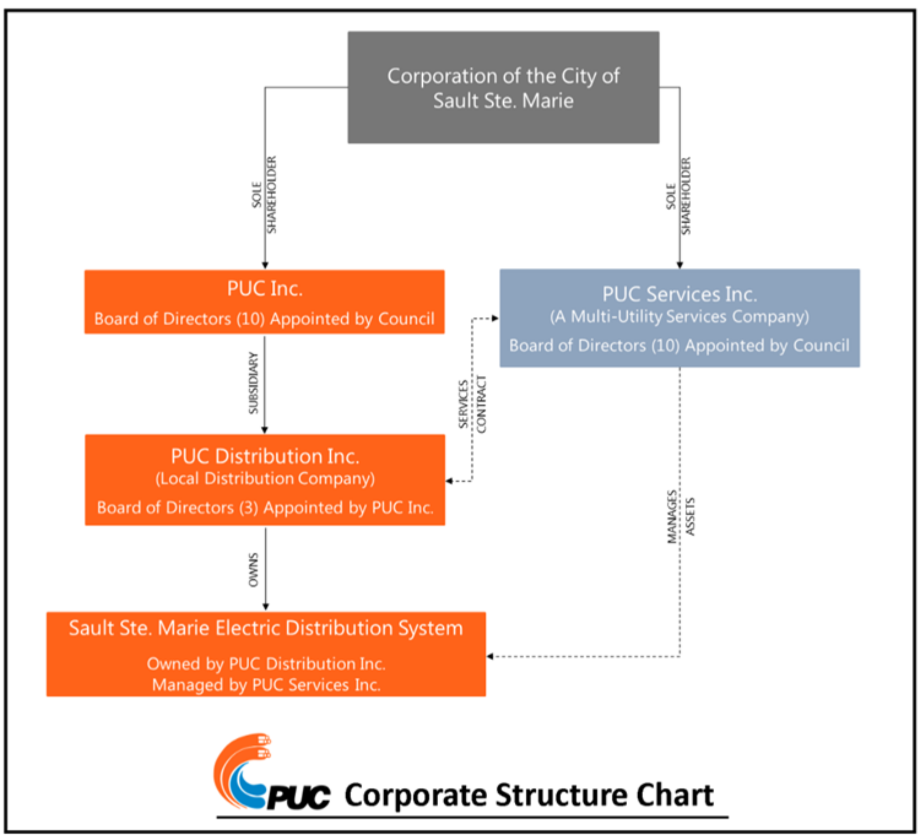
2. Overview and Ownership

PUC is an LDC licensed to distribute electricity in its service territory which includes most of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. In addition to distributing electricity, PUC is the default supplier of energy to customers within its service territory that do not contract with a retailer for their energy supply.

In accordance with Section 142 of the Electricity Act, 1998 the existing electricity assets of the City of Sault Ste. Marie Public Utilities Commission were transferred to PUC, a “for profit” corporation incorporated under the Ontario Business Corporations Act. PUC is 100% owned by PUC Inc., a holding company owned 100% by the City of Sault Ste. Marie (“the City”). The transfer was completed in 2000 and as required by Bill 210 in 2003, the City, through a Council resolution, affirmed that the electric utility should remain an OBCA “for profit” corporation.

PUC must operate its business in compliance with all applicable laws, including the Electricity Act, 1998, the Ontario Energy Board Act, 1998, the Ontario Business Corporations Act, and the rules, policies and requirements of the OEB including the Distribution System Code, the Affiliate Relationships Code, the Retail Settlement Code, the Standard Supply Service Code, the Accounting Procedures Handbook and Uniform System of Accounts, as well as the applicable Rate Handbook and Filing Requirements.

PUC, through its affiliate PUC Services Inc., operates using a shared services model. PUC regularly updates the allocation model as validated through a third-party provider (BDR – 2021). This model provides significant efficiency benefits across all of the utilities under the PUC umbrella. PUC Services Inc. shares certain resources with affiliates to create economies of scale and scope. The corporate structure and ownership of PUC is illustrated in the diagram below.



The Business is structured and operated to earn returns permitted under the provincial regulatory framework. PUC has its rates approved by the OEB. Although PUC does not pay corporate income taxes, as a municipally owned licensed LDC in the province of Ontario, PUC is required to remit Payments in Lieu of Taxes (PILS) to the province. The amount payable is generally calculated based on Federal and Provincial tax rules for corporations.

As of 2022, PUC serves an area of approximately 342 square kilometers, with a combined population of approximately 75,300. The service territory includes approximately 33,865 customers.

3. COS Filing

A COS, scheduled to be filed by PUC on August 31, 2022, for May 2023 rates, sets a price for a service based on the costs to provide it. The OEB will approve the revenue for PUC's 2023 year based on the sum of a prescribed rate of return on rate base (net fixed assets and working capital); operating, maintenance and administration ("OM&A") expenses; depreciation, interest expense; and tax. Distribution rates for the subsequent four years are limited to inflationary increases with a productivity adjustment and as a result, the COS Application will set the basis for the next five years of distribution revenue.

The OEB will review the COS Application through a public process. Documents are posted on the OEB's website and updated as the OEB reviews the application. Consumer groups and other affected groups (intervenors) may also take part in the process and provide comments. A series of clarification questions will be exchanged between the parties – PUC and intervenors/OEB staff. A full hearing may also ensue. The process will likely continue into 2023 in advance of the OEB's final decision on the application.

A successful COS outcome is critical to PUC's success, and management is committed to ensuring the following COS objectives are met:

- Incorporate customer interests and preferences
- Ensure all assets are constructed, operated and maintained in a condition which is safe for all employees, contractors, and the public
- Demonstrate ongoing continuous improvement while delivering on system reliability and quality objectives
- Demonstrate value for money
- Replace deteriorated aging infrastructure where warranted
- Address innovation and grid modernization

- Ensure reasonable distribution rates
- Effectively manage risk – financial, operational, cyber security, regulatory, privacy
- Ensure public policy responsiveness

4. Mission and Strategic Objectives

In 2020, PUC undertook a process to develop a strategic plan that would provide the company with clarity and direction, connecting PUC's vision for the future with its strategic objectives. The process, which included participation from community members, employees, PUC's shareholder, and the Board of Directors, resulted in updates to PUC's Mission, Vision, and Core Values

The PUC Mission, Vision and Core Values were further refined to ensure alignment with the OEB's Renewed Regulatory Framework for Electricity Distributors ("RRFE"). It is a performance-based approach identifying four desirable outcomes:

RRFE Performance Outcomes	Strategy	Strategic Objectives
Customer Focus	Build a customer-centric organization	Services are provided in a manner that responds to identified needs and preferences of customers.
Operational Effectiveness	Build a future company that is sustainable Maximize value	Continuous improvement in productivity and cost performance is achieved while LDC delivers on system reliability and quality objectives.
Public Policy Responsiveness	Regulatory Compliance	LDC delivers on obligations mandated by governments.
Financial Performance	Financial integrity and accountability Drive profitable and sustainable growth	Financial viability is maintained and savings from operational effectiveness are sustainable.

In conjunction with the Mission, Vision, and Core Values, PUC has set three strategic Focus Areas and Aspirations:

Focus Area & Aspiration	Strategic Long-Term Goals	Strategy to Achieve Success	Objectives
Customers "Our customers trust us"	Achieve and maintain an exceptional customer satisfaction rating Meet or exceed all OEB scorecard targets	Improve service quality management (responsiveness, entrepreneurial, high quality) Advance customer focus (customer satisfaction, communication, engagement, education)	Achieve OEB scorecard targets Increase MyPUC app usage
Employees "Our Employees Appreciate us"	Recognized as one of Canada's top 100 Employers A culture of safety excellence	Implement leading organizational transformation (employee engagement, operational excellence, talent management) Continuous improvement of safety culture and performance through an Integrated Safety Management Program	Continue accountability leadership training for all staff Develop a diversity, equity, and inclusion strategy Zero high-risk lost time incidents Zero high-risk employee safety incidents Contractor safety program
Shareholder "Our Shareholder Commends us"	Achieve OEB deemed return on equity for shareholder Achieve infrastructure sustainability Continuous productivity/business process improvement Increase enterprise value	Ensure sustainability of assets and system Productivity/business process improvements Explore permitted business opportunities	Achieve infrastructure sustainability File cost of service rate application Complete Sault Smart Grid (SSG) project Continuous productivity/business improvements

PUC's focus on sustainability has been an effective way to increase innovation capability, reduce the company's carbon footprint and enable significant growth. By weighing all decisions through this lens, PUC has identified, pursued, and launched several new opportunities that are rooted in community partnerships and innovative ideas.

5. Key Success Factors

The following five key success factors will help PUC create a best-in-class utility:

1. ***Completion of a DSP*** – This comprehensive engineering plan outlines PUC's asset management strategy and capital expenditure plans over a five-year horizon. PUC's plan provides clarity, direction and focus connecting PUC's vision for the future to its core strategies and strategic objectives. Customers, Employees, and Shareholders are the focus and at the forefront of PUC's DSP.

   In addition to the core values above, the fundamental objective of PUC's asset management program is to manage planning and engineering prudently and efficiently. This entails ensuring the design, inspection, maintenance, replacement, and retirement of all distribution assets are done in a sustainable manner that maximizes safety and customer reliability, while optimizing asset lifecycle costs.

2. ***People, Culture and Safety Strategy*** – Succession planning, employee growth and engagement will ensure that PUC has the right people in the right jobs over the coming years. Human resources and safety policies will position PUC as one of the top employers in Canada. Safety is always a top priority in PUC's plans and budgets. This includes both safety for the public and the safety of PUC employees.

   PUC is dedicated to creating a welcoming environment that encourages and promotes diversity, cross-culture working experiences and strong relationships within the community and with partners. PUC will strive to demonstrate leadership and foster a workplace culture where all employees feel empowered to bring their authentic selves to the workplace and do their best work.

3. ***Customer-Centric*** – With its COS, PUC reached out to customers through the biennial customer satisfaction survey as well as through specific COS surveys to gather feedback and confirmation on how PUC is doing. PUC is continually looking for ways to create positive experiences for customers, while at the same time encouraging behaviour that is more responsive to energy conservation. This has resulted in the launch of the MyPUC app, along with other consistent, proactive communication methods that are conducive to two-way interaction. A summary of PUC's customer engagement and how it impacts this business plan is provided in Appendix B.

4. ***Financial Success*** – PUC strives to produce consistent, allowable earnings, with returns that meet the expectation of PUC's Shareholder. The focus is on growing value through

investment and innovation. PUC continues to build on partnerships with other LDCs and organizations to strengthen the utility.

5. ***Innovation*** – Building on the strong culture of innovation PUC has created throughout the organization, PUC will engage all staff to look for ways to improve efficiency and reduce costs through innovation. This includes initiatives such as "'becoming paperless" with creating electronic forms, promoting e-billing to customers, and also improving efficiencies in how we operate.

6. Key Challenges, Risks and Mitigation

PUC continues to set risk management as a top priority. It has implemented an Enterprise-wide Risk Management (ERM) program whereby the Senior Leadership Team become Risk Owners for one or more risks. They assume full accountability for successful management of their risk(s), including actions plans for risk mitigation and report on progress regularly. Over the COS horizon, the corporate risk register will continue to be reviewed to ensure that risks with a potential to affect the organization from a safety, reputation, financial and personnel perspective are identified and addressed. This will enable PUC to deliver on its commitments as presented with the COS.

The following business risks have been identified, and mitigation strategies are in place:

Weather

Mitigation of material weather-related impacts on costs (e.g., ice storms, high winds, etc.) can be achieved in different ways, including by improving the resiliency of PUC's assets through design changes and proactive management of right-of-way. Risk exposure can also be reduced through a request for a z-factor adjustment application before the OEB. The current materiality threshold for z-factor adjustments is 0.5% of distribution revenue, which for PUC is approximately $0.1 million per event.

Weather-related impacts on distribution revenue, as well as energy conservation efforts, cannot be mitigated in the short term, although evidence will be presented in the COS to mitigate the future impact of a weather-related declining revenue trend. Such evidence would generally include the presentation of weather-normalized data as a basis for determining customer-specific volumetric distribution charges. In addition, the transition to a fully fixed monthly charge for residential customers was completed in 2020, resulting in approximately 67% of distribution revenue being fixed monthly.

Local Economy and Credit Risks

LDCs in general are challenged to mitigate short-term impacts on distribution revenue resulting from declining consumption and poor economic conditions. These aspects are considered to be normal business risks for LDCs and must be taken into consideration as part of the development of the load forecast underlying the COS.

As part of its COS, PUC will provide a load forecast derived from a multi-factor, single-equation econometric model. The model includes such parameters as weather (heating degree-days, cooling degree-days), number of customers, calendar variables (days in month, number of peak hours), and a trend variable. LDCs are exposed to revenue fluctuations during the IRM rate periods from variances between actual loads and the load forecasts underlying distribution rates at the time of the COS filing.

PUC faces credit risk primarily from non-payment of hydro bills by large commercial account customers. The company's revenue is earned from a broad base of customers; it does not earn a significant amount of revenue from any single customer. Although not a direct customer of PUC, the performance of the City's largest employer poses a material risk to PUC because of its impact on residents and businesses that are customers of PUC.

PUC's top ten customers represent 6% of distribution revenue, which exposes PUC to credit risk from these customers. However, of the top ten customers, only one is a private corporation, the remainder are federal, provincial, or municipal government entities which reduces the credit risk. Additionally, a systemic downturn could also expose PUC to credit risk from other customer classes. To deal with this risk, PUC has adopted credit policies as permitted by OEB regulation that result in a reasonable level of credit risk mitigation. PUC does not provide significant electric supply to the major industries in the municipality, however, financial difficulties at these companies could adversely affect the entire community and thus the distribution utility.

Equipment Failure

Equipment failures have an effect on service reliability to customers. By recently completing an Asset Management Plan ("AMP") and a DSP, PUC has adopted a systematic plan to replace its aging infrastructure. Equipment failure risk is managed through such programs as the annual tree-trimming program, infrared surveys of plant and equipment, non-destructive pole testing and treatment, oil testing of power transformers, and by maintaining an adequate inventory of replacement parts.

Regulatory Risk

Regulatory risk is the risk that the Province and its regulator, the OEB, could establish a regulatory regime that imposes conditions that significantly reduce the rate of return that can be earned by electricity distributors. In addition, the ability to maintain the distribution system depends on, among other factors, the OEB allowing recovery of the OM&A and capital costs required in the future. Lower rates arising from these types of changes could result in distribution earnings and cash flow being lower than the rate increases assumed in the Business Plan.

Failing to continually be aware of and applying changing government regulations is also a corporate risk. The company monitors developments in the electricity industry and relies on the Electricity Distributors Association ("EDA") to monitor and act on its behalf. Consultants with expertise in certain fields are utilized as required. Further, PUC is a member of the Utilities Standards Forum ("USF") and actively participates in various Regulatory Working Groups as a means to keep abreast of changes in Regulations, provide insight on emerging issues and network industry best practices.

In the past, OEB amendments to regulations, codes and guidelines have been experienced in the following areas such as:

- Restrictions on disconnecting electric services for non-payment;
- Length of advance notice prior to a disconnection;
- Bill due dates and late payment charges;
- Security deposits;
- Allocation of payments;
- Equal monthly billing plans; and
- Arrears payment arrangements.

Management continues to monitor the OEB's amendments to customer service rules and will analyze the financial impact of any changes required by the OEB in a timely manner.

Human Resources Risk

Acquisition and retention of human resources to support existing operations and new business requirements remain a continuous risk to manage. PUC Services Inc., like others in the utility services industry, faces a significant number of retirements over the next several years. The retirement of individuals in technical, trades and management positions will result in the loss of a significant pool of expertise, therefore where practical replacements are hired in advance of projected retirements to promote the transfer of knowledge. Further, management and staff have committed to making a priority to develop and implement a talent strategy that attracts and retains qualified candidates to meet the company's recruitment needs.

As part of the management services contract, PUC Services Inc. provides the workforce necessary to operate PUC. Labour disruptions can affect ongoing operations. Collective agreements with the union employees in PUC Services Inc. are in effect until April 30, 2024.

Technology Risk

The use and complexity of the company's electronic infrastructure continue to increase, and its reliability and security are critical to all areas of operation. As part of the management service contract with PUC Services Inc., an information technology (IT) department oversees networks, voice over internet protocol communications, enterprise software, smart meter operation, systems security, and other emerging IT issues. Further, PUC Services Inc., has established a dedicated Information Security (IS) department that reports directly to the President & CEO. This department oversees the cybersecurity configuration of all systems and network devices within the technology infrastructure. It monitors all cyber alerts and ensures mitigating solutions are in place to protect confidentiality, integrity, and availability of all data and applications. It delivers a corporate-wide staff training program to address cybersecurity issues and is actively participating in the USF's Cybersecurity and Privacy working groups. PUC completed the Cybersecurity implementation plan developed to meet the requirements of the OEB Cyber Security Framework. PUC continues to strive for full compliance with the recommended measures and reporting requirements to mitigate cyber security risks.

Business Continuity Risk

Business Continuity Planning (BCP) is an important part of PUC's risk management strategy. During the COVID pandemic, PUC's Business Continuity Plan was challenged and updated to ensure PUC could continue to operate safely and efficiently. Every department in the organization was involved in the process of creating systems of prevention and recovery to ensure PUC's goal of enabling ongoing operations and delivery of essential services to customers was met. This process included comprehensive tabletop exercises that took into account critical resource planning, alternate facilities, mission essential functions, succession planning and worker and public safety procedures.

7. Financial Performance Projections

This report summarizes PUC's estimated results for 2022 and 2023 budgets (test year budget) and 2024 – 2027 projections.

The Business Plan is based on the following assumptions and constraints:

1. A distribution revenue increase in 2023 of approximately $4.1M based on the estimated increase as a result of the COS to be submitted (rebased recovery of requested OM&A expenses, depreciation expense and PILs expense, plus a return on asset base as prescribed by the OEB).
2. An annual distribution revenue increase in 2024 to 2027 of 2.0% based on the estimated Incentive Rate Mechanism (IRM) annual increase leading up to the next COS in 2028. The projections are also based on historical consumption levels.
3. Subsequent to 2023, expense increases are estimated at 2.0% per year.
4. Prudent investment in distribution plant so that ratepayers can continue to be provided with excellent service and reliability.
5. Continued improvement to customer communication and engagement to best serve customers.
6. Long-term view of return on shareholder investments.
7. Continuing to seek improvements in productivity in order to provide current and future mandated levels of service to customers at a cost at inflation or less.
8. Managing economic and political uncertainty.
9. Reducing the debt-to-equity ratio over a number of years to the OEB deemed level of 60/40%.

PUC High-Level Financial Budgets and Projections:

PUC's Financial Plan summary is provided in Appendix A. The Plan provides for prudent and sustainable investment in core business operations and subject to certain material risks, results in the following metrics:

Description	2023 Test	2024 Projection	2025 Projection	2026 Projection	2027 Projection
Liquidity: Current Ratio	0.89	1.01	1.07	1.23	1.14
Debt to Equity Ratio	2.36	2.24	2.11	1.99	1.85
Projected Return on Equity	6.80%	7.61%	7.50%	7.29%	7.14%
Deemed Return on Equity	8.66%	8.66%	8.66%	8.66%	8.66%
Interest payments to S/H	$1.62M	$1.62M	$1.62M	$1.62M	$1.62M
Dividends to S/H	$0.61M	$0.61M	$0.61M	$0.61M	$0.61M

PUC's future target is to achieve its deemed return on equity while maintaining liquidity and leverage ratios that are relatively consistent with historical levels.

The Business Plan provides for prudent and sustainable investment in core business operations. The achievement of this plan is subject to obtaining approval for rates in 2023 as requested and to business risks as noted above. Following is a summary of the five-year financial plan that is attached in Appendix A:

Description ($ M)	2023 Test	2024 Projection	2025 Projection	2026 Projection	2027 Projection
Net Income	$3.12	$3.60	$3.75	$3.90	$4.07
Distribution Revenue	$23.78	$25.28	$25.79	$26.30	$26.83
OM&A Expenses	$13.53	$14.20	$14.48	$14.77	$15.06
Depreciation	$5.43	$5.67	$5.85	$6.04	$6.47
Capital Expenditures (net)	$10.11	$7.24	$7.47	$6.61	$10.79
Working Capital	($5.97)	($3.20)	($2.10)	($0.01)	($2.45)

Net Income

Overall, net income is increasing from 2023 to 2027 as a result of the rebasing of distribution rates. The 2023 budget includes only a portion of the increase, as it is anticipated that the rate increase will take place on May 1, 2023. Net income increases again in 2024 as the rebased rates will be effective for the entire year. The principal driver of the increase in net income in 2023 corresponds to the significant capital investments over the past five years leading to an increase in rate base.

Distribution Revenue

The 2023 planned distribution revenue has been determined based on re-setting the distribution rates that PUC charges its customers to be applied for with the OEB in PUC's 2023 COS. It is expected that PUC will file its application with the OEB on August 31, 2022. Revenue is based on PUC's budget for OM&A and depreciation expenditures, payments in lieu of taxes, and an allowable regulatory return on capital. PUC is requesting that the OEB approve an average increase to its 2023 distribution rates of 18% when compared to 2022 rates. This increase is mainly driven by the return on rate base, and associated depreciation due to the increase in Net Book Value of capital assets.

Preliminary bill impacts indicate that a typical Residential customer consuming on average, 750 kWh per month, would see their total bill increase by about 3.03%. Bill impacts for the typical General Service customer consuming on average, 2,000 kWh per month, would see their total bill increase by about 4.4%. However, the final bill impacts that will be requested from the OEB are not known yet as PUC is still working on preparing its application, and the application will be subject to review by the OEB and intervenors through the rate application process. The outcome of the rate proceeding may result in OEB approving a different revenue requirement than is originally requested.

PUC is preparing a strong case, supported by third-party expert reports to justify the need for rate increases. PUC needs to continue investing in people, technologies, and processes to support its customers and to operate a sustainable business that provides a safe and reliable service expected by its customers. The COS provides justification for the level of expenditures needed to run PUC effectively, in addition to providing value to its customer base and earn its regulated rate of return.

Operating Expenses

The average non-labour OM&A inflation rate in the 2023 test year is 3.0% per year and 2.0% in 2024 through 2027. The 2.0% for 2024 through 2027 is the benchmark that the Bank of

Canada is striving to achieve. Therefore, this is applied to both revenue and expenditures so that any change to inflation will be stabilized in the financial forecast.

A collective agreement was ratified in March 2022, providing the terms and conditions of employment for unionized staff within PUC from April 1, 2021, to April 30, 2024. Annual general union and non-union labour inflation is assumed to be 2.0% for the years 2023-2027.

The following table provides the 2023 to 2027 sources of OM&A expenditures.

Description ($M)	2023 Test	2024 Projection	2025 Projection	2026 Projection	2027 Projection
Operations	$7.28	$7.43	$7.57	$7.73	$7.88
Billing and Collecting	$2.04	$2.08	$2.13	$2.17	$2.21
Administrative	$4.21	$4.68	$4.78	$4.87	$4.97
Total OM&A	**$13.53**	**$14.19**	**$14.48**	**$14.77**	**$15.06**

Working Capital

Working capital remains at a low level through the earlier years of the projection period. Elevated capital expenditures, including SSG and the Substation 16 rebuild, in addition to current debt service obligations, have outweighed cash generated from operations and new borrowings. PUC's challenge is to continue to provide service to customers in the regulated rate environment where revenue increases are capped at less than inflation and ever-evolving regulations increase OM&A expenses in a local economy that is not expanding. An increase in working capital will be attained through lower capital expenditures and additional financing.

Despite the moderate rate increases expected in the IRM years, management believes that it can deliver PUC's capital plan and manage costs effectively and in a manner that continues to deliver quality distribution service safely and reliably for ratepayers. The Business Plan reflects managed increases in expenditures with due regard for the following:

- Expectations set by the OEB regarding the nature and magnitude of expenditures.
- Prioritization of investments in the context of requirements for distribution system renewal and the needs of PUC's ratepayers.
- Advancement of business processes through replacement or new investments in information technology systems and technology-based processes.
- Continued improvement to customer engagement and communication.
- Customer affordability.
- A reasonable rate of return for the shareholder.

PUC's target for the forecast period is to balance inflationary OM&A cost increases with productivity and efficiency improvements, consistent with the price-cap adjustment factors inherent in the OEB's IRM rate-setting framework.

Capital Expenditures

PUC's overall system planning, and capital expenditure planning process ensures PUC continues to provide safe, reliable, and efficient distribution of electricity to its customers. Capital investments are required to maintain adequate security of supply to meet customer needs, as well as to replace end-of-life assets. PUC has updated its DSP and AMP that both identify areas of the distribution system that should be the focus of resources in order to maintain reliable service to customers. In 2022, capital expenditures include the substantial completion of the SSG as part of System Service assets.

Planned Capital Expenditures

Planned Capital Expenditures ($M)	**2022 Budget**	**2023 Test**	**2024 Projection**	**2025 Projection**	**2026 Projection**	**2027 Projection**
System Access	$ 1.84	$ 2.34	$ 2.67	$ 2.79	$ 2.49	$ 2.36
System Renewal	$ 6.63	$ 4.60	$ 4.24	$ 3.44	$ 3.55	$ 2.57
System Service	$ 28.71	$ 3.19	$ 0.13	$ 0.84	$ 0.75	$ 5.86
General Plant	$ -	$ 0.58	$ 0.81	$ 1.03	$ 0.43	$ 0.63
Total Expenditures, Gross	$ 37.18	$ 10.71	$ 7.85	$ 8.11	$ 7.22	$ 11.42
Capital Contributions	$ (7.85)	$ (0.59)	$ (0.62)	$ (0.64)	$ (0.61)	$ (0.62)
Total Expenditures, Net	**$ 29.33**	**$ 10.11**	**$ 7.24**	**$ 7.47**	**$ 6.61**	**$ 10.79**

Financing

No changes have been made to the current financial structure in this financial plan. Debt to equity, which includes shareholder debt, is currently 69% debt and 31% equity in comparison to the deemed debt to equity of 60/40%. The interest payment to the shareholder remains at $1.62M throughout the projection period. The financial plan results in a debt-to-equity level of 70/30% by 2023, falling to 65/35% by 2027.

8. Revenue Requirement/Revenue Deficiency

PUC's COS is intended to set rates that will recover the 2023 base revenue requirement identified in the table below. The following illustrates that revenues at current rates are insufficient to recover this revenue requirement, resulting in a net revenue deficiency of $4.07M, confirming the need for PUC to proceed with its scheduled COS.

Revenue Deficiency Determination ($M)

Description	Current Rates		Proposed Rates	
Revenue				
Revenue Deficiency from below			**$**	**4.07**
Distribution Revenue	$	20.84	$	20.84
Other Operating Revenue offsets	$	2.75	$	2.75
Total Revenue	**$**	**23.59**	**$**	**27.66**
Costs and Expenses				
Operating Expenses	$	19.37	$	19.37
Deemed Interest Expense	$	3.09	$	3.09
Total Costs and Expenses	**$**	**22.46**	**$**	**22.46**
Utility Income Before Income Taxes	**$**	**1.13**	**$**	**5.20**
Income Taxes:				
Corporate Income Taxes	$	(0.59)	$	0.49
Total Income Taxes	**$**	**(0.59)**	**$**	**0.49**
Utility Net Income	**$**	**1.72**	**$**	**4.71**
Utility Rate Base	$	135.93	$	135.93
Actual Return on Rate Base		3.54%		5.74%
Target Return - Equity on Rate Base		5.74%		
Deficiency/Sufficiency in Return on Equity		-2.20%		
Revenue Deficiency/(Sufficiency) after tax	$	2.99		
Gross Revenue Deficiency/(Sufficiency)	**$**	**4.07**		

PUC has incorporated these final projections for 2024 and its effect on revenue requirement on its scorecard metrics provided in Appendix C.

9. Bill Impacts

Based on a new revenue requirement of $27.6M in 2023, the following table outlines the bill impacts for the following rate classes:

Average monthly Total Bill	Current Approved Rates	Proposed Rates	Change $	Change %
Residential Customer (750 kWh)	$ 122.56	$ 126.28	$ 3.72	3.03%
Small General Customer (2,000 kWh)	$ 309.53	$ 323.16	$ 13.63	4.40%
Large General Customer (145 kw)	$ 9,533.29	$ 9,335.77	$ (197.52)	-2.07%

Distribution Rate only Impact	Current Approved Rates	Proposed Rates	$	Change %
Residential Customer (750 kWh)	$ 35.88	$ 42.48	$ 6.60	18.39%
Small General Customer (2,000 kWh)	$ 80.27	$ 95.49	$ 15.22	18.96%
Large General Customer (145 kw)	$ 1,244.61	$ 1,440.10	$ 195.49	15.71%

Incorporated in the overall monthly bill impact is the effect of the following major components of the electricity bill:

- Distribution rates (monthly service charge and volumetric rates);
- Disposition of deferral and variance accounts:
- Revised Retail Transmission rates;
- Regulatory Charges; and
- Loss Factors.
- Revised Embedded Generation Rate Rider Refund
- Rate Rider Refund for Loss Carry forwards
- VVO Consumption Savings from Sault Smart Grid

Overall PUC believes that the bill impacts are reasonable for its customers and properly aligns its rising costs with affordable rates.

10. Conclusion

This 2023-2027 Business Plan for PUC reflects its focus on being sustainable while balancing reliability and affordability for customers. Overall, the plan supports a successful COS, and management remains committed to being prudent in its expenditures and investments throughout the five-year period while not sacrificing the excellent service customers have come to rely on.

PUC Distribution Inc.
Balance Sheet

	For the Year Ending December 31					
	2022 Budget	2023 Budget	2024 Projected	2025 Projected	2026 Projected	2027 Projected
Assets						
Current Assets	$21,518,045	$22,847,794	$25,951,171	$27,475,780	$31,527,525	$29,249,329
Future Taxes	$0	$0	$0	$0	$0	$0
Net Fixed Assets	$131,086,455	$135,426,047	$136,987,384	$138,611,506	$139,151,077	$143,705,283
Regulatory Assets	$9,437,146	$9,437,146	$9,437,146	$9,437,146	$9,437,146	$9,437,146
	$ 162,041,646	$ 167,710,987	$ 172,375,701	$ 175,524,432	$ 180,115,747	$ 182,391,758
Liabilities						
Current Liabilities	$27,912,361	$28,224,789	$28,390,228	$28,599,927	$29,583,468	$29,662,991
Notes Payable	$83,669,826	$86,520,291	$88,030,694	$87,831,397	$88,148,560	$86,886,200
Deferred Revenue	$7,034,528	$7,034,528	$7,034,528	$7,034,528	$7,034,528	$7,034,528
Regulatory Liabilities	$696,821	$696,821	$696,821	$696,821	$696,821	$696,821
Deferred tax liabilities	$1,989,000	$1,989,000	$1,989,000	$1,989,000	$1,989,000	$1,989,000
	$121,302,537	$124,465,429	$126,141,271	$126,151,674	$127,452,377	$126,269,540
Shareholder Equity						
Common Shares	$20,062,107	$20,062,107	$20,062,107	$20,062,107	$20,062,107	$20,062,107
Retained Earnings	$20,677,002	$23,183,451	$26,172,323	$29,310,651	$32,601,263	$36,060,111
	$ 40,739,109	$ 43,245,558	$ 46,234,430	$ 49,372,758	$ 52,663,370	$ 56,122,218
Total Liabilities and Shareholder Equity	$ 162,041,646	$ 167,710,987	$ 172,375,700	$ 175,524,432	$ 180,115,747	$ 182,391,758

PUC Distribution Inc.
Statement of Comprehensive Income

	For the Year Ending December 31 2022 Budget	2023 Budget	2024 Projected	2025 Projected	2026 Projected	2027 Projected
<u>Revenue</u>						
Net Electricity Distribution Revenue	$ 20,336,375	$ 23,782,600	$ 25,281,653	$ 25,787,286	$ 26,303,032	$ 26,829,093
Other Revenue	$ 2,509,522	$ 2,750,265	$ 2,770,628	$ 2,791,398	$ 2,812,583	$ 2,834,192
	$ 22,845,897	$ 26,532,865	$ 28,052,281	$ 28,578,684	$ 29,115,615	$ 29,663,284
<u>Expenses</u>						
Operations	$ 6,680,445	$ 7,280,465	$ 7,426,074	$ 7,574,596	$ 7,726,088	$ 7,880,609
Billing and Collecting	$ 1,934,849	$ 2,043,800	$ 2,084,676	$ 2,126,370	$ 2,168,897	$ 2,212,275
Administrative	$ 3,540,744	$ 4,209,435	$ 4,684,217	$ 4,777,902	$ 4,873,460	$ 4,970,929
Operating Expenses	$ 12,156,038	$ 13,533,701	$ 14,194,968	$ 14,478,867	$ 14,768,444	$ 15,063,813
Depreciation	$ 4,473,172	$ 5,425,413	$ 5,669,538	$ 5,850,310	$ 6,037,171	$ 6,201,589
Property Taxes andLEAP	$ 369,215	$ 415,575	$ 423,887	$ 432,364	$ 441,012	$ 449,832
Operating and Depreciation	$ 16,998,425	$ 19,374,689	$ 20,288,392	$ 20,761,541	$ 21,246,627	$ 21,715,234
Income from Operating	$ 5,847,472	$ 7,158,177	$ 7,763,889	$ 7,817,143	$ 7,868,988	$ 7,948,050
Interest Expense	$ 3,094,507	$ 3,943,634	$ 4,053,307	$ 3,952,721	$ 3,847,818	$ 3,753,730
Income before taxes	$ 2,752,965	$ 3,214,543	$ 3,710,582	$ 3,864,422	$ 4,021,170	$ 4,194,320
Income taxes	$ 84,299	$ 98,013	$ 111,631	$ 116,013	$ 120,479	$ 125,392
Net Income	$ 2,668,666	$ 3,116,529	$ 3,598,951	$ 3,748,408	$ 3,900,692	$ 4,068,928
Opening Retained Earnings	$ 18,456,616	$ 21,125,282	$ 24,241,812	$ 27,840,763	$ 27,840,763	$ 31,589,172
Net Income	$ 2,668,666	$ 3,116,529	$ 3,598,951	$ 3,748,408	$ 3,900,692	$ 4,068,928
Dividends	$ -	$ -	$ -	$ -	$ -	$ -
Closing Retained Earnings	$ 21,125,282	$ 24,241,812	$ 27,840,763	$ 31,589,172	$ 31,741,455	$ 35,658,100

PUC Distribution Inc.
Statement of Working Capital

	For the Year Ending December 31 2022 Budget	2023 Budget	2024 Projected	2025 Projected	2026 Projected	2027 Projected
Opening Working Capital	($7,342,222)	($6,678,829)	($5,973,935)	($3,201,437)	($2,096,226)	($11,563)
Net Income	$ 2,668,666	$ 3,116,529	$ 3,598,951	$ 3,748,408	$ 3,900,692	$ 4,068,928
Add Depreciation	$ 4,473,172	$ 5,425,413	$ 5,669,538	$ 5,850,310	$ 6,037,171	$ 6,201,589
Less Net Capital Expenditures	$23,097,501	$9,765,005	$7,230,875	$7,474,433	$6,576,741	$10,755,796
Add Loan Proceeds	$ -	$ -	$ 4,000,000	$ 4,000,000	$ 5,500,000	$ 4,000,000
Less Principle Repayments	$2,011,730	$2,324,158	$2,489,597	$2,699,296	$3,682,837	$3,762,360
Ending Working Capital	$ (25,309,615)	$ (10,226,050)	$ (2,425,918)	$ 223,553	$ 3,082,058	$ (259,202)
Working Capital	($6,678,829)	($5,973,935)	($3,201,437)	($2,096,226)	($11,563)	($2,448,805)

Appendix B - Customer Engagement

As a trusted utility provider for over 100 years, PUC is continually looking for ways to create positive experiences for customers, while at the same time encouraging behaviour that is more responsive to energy conservation. PUC is always striving to use innovation to improve communication – and trust - with customers. PUC recognizes that as the utility industry evolves, so do their customers' needs and expectations.

PUC's five-year strategic direction provides clarity, direction and focus connecting PUC's vision to improve communities through curiosity and innovation, with the company's core strategies and strategic objectives. Customers are one of PUC's three areas of strategic focus, along with employees and PUC's shareholder. PUC's strategic long-term goal is to achieve and maintain an exceptional satisfaction rating, and strategies to achieve success in this area include advancing customer communications and engagement, and creating an improved, ease of use experience.

Over the past five years, improving communications, community relations and the overall customer experience have been identified as strategic priorities for the company. Through this focused approach, PUC has been able to effectively engage with customers through meaningful, two-way communication, and improve upon the customer experience through a "one-stop-shop" methodology for first point of contact.

In 2020, PUC developed a new brand promise to customers that states "we lead the way through innovation and compassion to deliver outstanding service every single day." Combined with PUC's core value of being 'customer-centric,' PUC has continually demonstrated their commitment to engaging customers over the past five years.

PUC uses various communication tactics to best serve its customers, such as:

- Digital Platforms (i.e., Mobile App, PUC website, Customer Connect Portal, social media, and digital advertising);
- Traditional Platforms (i.e., phone and mail, media, print, radio advertising);
- Community Outreach (i.e., attendance at community events, townhalls, open houses, school safety program); and
- Customer Surveys.

Through regular customer engagement surveys, PUC has been able to incorporate important customer feedback when evaluating PUC's priorities moving forward. Surveys have also provided opportunities for education and awareness regarding PUC's operations, improvements to service and strategic initiatives.

Since PUC's last cost of service application filing, it has engaged customers in the following eight surveys:

1. Two (2) UtilityPULSE Customer Satisfaction Surveys (2019, 2021)
2. Four (4) Customer Pulse surveys (in 2020)
3. Two (2) Cost of Service-related surveys (2021, 2022)

As each survey is analyzed, several common themes have surfaced, providing PUC with greater insight into the needs and wants of customers. Those common themes include:

- Customers want improved communications;
- Customers place a high value on energy saving initiatives and PUC lowering their carbon footprint;
- Customers place a high value on reliability, cyber security, and upgrades to infrastructure;
- Customers place high importance on reasonable electricity rates.

Below provides a more detailed summary of the surveys conducted, and how PUC has responded.

<u>UtilityPULSE Customer Satisfaction Surveys</u>

In 2019 and 2021, PUC conducted its biennial Customer Satisfaction Surveys with UtilityPulse. The objective of these surveys is to capture perceptions about customer needs and wants as well as gather information to support discussions and improve the customer experience at every level in the organization.

During the period of September 2019, 400 customers completed a telephone interview, providing a confidence level of 95% (+/- 4.9%). The survey represented 85% residential and 15% commercial.

PUC received a Credibility and Trust Rating of 87% and an Overall Satisfaction Rating of 94%. From this survey, customers expressed that the following should be priorities for PUC:

- Pro-actively maintaining and upgrading equipment
- Reducing response times to outages
- Investing in projects to reduce the environmental impact of the utility's operations
- Investing more in the electricity grid to reduce outages

Based on this feedback, PUC has made significant investments through the Sault Smart Grid project that will result in upgrades to equipment, a reduction in the response times to outages, a reduction in the number of outages and a reduction PUC's environmental impact through more efficient energy consumption. In addition, PUC has purchased electric vehicles and developed a plan to further electrify their fleet to lower maintenance and fuel costs and lower their carbon footprint.

PUC received an A rating. PUC received a score of 83% on the customer centric engagement index (CCEI), compared to 82% in Ontario.

From this survey, customers expressed that the following should be priorities for PUC:

- Movement to more digitization
- Improvements to communication (more pro-active approaches)
- Better prices and lower rates
- Simplified billing
- Enhance cyber security measures

Based on this feedback, PUC has put in place a digitization strategy, with a goal of going paperless by 2024. Since the initiative was launched in 2019, PUC has reduced day to day printing dramatically, increased on-line payments to vendors, enhanced the customer experience by providing flexibility, and restructured processes internally for employees to promote efficiencies. Some specific examples include the promotion of e-billing for customers, the development of the MyPUC App, the elimination of printed paystubs, an increase in Electronic Fund Transfers from 8% to over 40%, and the development of an online employee portal, Dayforce.

PUC has improved pro-active communications through the development of the MyPUC App, and the increased use of social media platforms and PUC's website. For example, in addition to ATLAS phone notifications, the MyPUC app and website now display information on planned power outages in advance, so that customers can properly prepare for the interruption.

PUC recognizes the threat that cyber security represents and is taking measures to mitigate that risk. PUC has made significant investments in cyber security infrastructure, including the addition of a Manager of Information Security.

In order to simplify billing, PUC has continued to encourage customers to sign up for preauthorized payments, e-billing and the MyPUC App. Lastly, PUC has made significant investments through the Sault Smart Grid project that will result in average customer savings of 2.7%.

Customer Pulse Surveys

In 2020, PUC conducted four online pulse surveys throughout the year to provide education and gain insight into how to better serve customers related to PUC's strategic and long-term planning. The message to customers was as follows:

"New Advances in technology are changing the way we distribute electricity, and as a result, are providing new options for customers. With new technologies, customers will be better equipped to exercise more control on their energy consumption, and technological advances mean safer options and an eventual decrease in the price of electricity.

All of this is possible, but it requires investments today so electricity will continue to be safe, reliable, and affordable for tomorrow."

Based on the results of those surveys, it was noted that PUC should:

- Look at ways to create energy savings for customers.
- Consider increasing bills if it means improvements to reliability, efficiency, and communications. The graph below displays this, as 72.12% customers stated they would place a value between $0.50 - $2.00 on future bills to improve reliability, efficiency, and communications.
- Make major investments in how PUC operates to reduce their carbon footprint. The first graph below displays that 60% customers stated reducing PUC's carbon footprint by making major investments in how it operates is either extremely or very important. The second graph below displays that 67% of customers stated that it is either extremely important or very important that PUC play a role in the community to promote the reduction of greenhouse gas emissions.
- Improve and enhance the customer experience. The graph below displays that 82.95% of customers stated they would like to see improvements to communication related to power outages.
- Look at ways to improve electrical reliability. The graph below displays that 72.64% of customers rated reliability as a 10 (on a scale from 1-10, 10 being the most important).

Through the increased use of social media platforms and website, and the development of the MyPUC App, PUC has made major efforts to be more pro-active with customer communications. For example, in addition to ATLAS phone notifications, the MyPUC app and website now display information on planned power outages in advance, so that customers can properly prepare for the interruption.

Cost of Service-related surveys

In 2021 and 2022, PUC conducted two online Customer Engagement Surveys. The purpose of surveys was to provide customers with a better understanding of the details behind PUC's proposed rate increase, along with an opportunity to share their feedback into future investment decisions at PUC which will inform PUC's Cost of Service Application.

The first survey (part one of two) was conducted in August-September 2021. 906 customers completed an online survey. Based on the results of this survey, it was noted that PUC should:

- Explore more options for customer communications and energy savings tools. The graph below shows that 38.96% of customers would like PUC to move ahead with an online chat portal. The second graph below shows that 74.56% of customers would be interested in tools to help decide between tiered and time-of-use pricing. The graph below shows that 44.12% of customers would like a notification when they hit certain consumption levels. All of these examples reflect customer's desire for new tools to support customer communications and energy savings.
- PUC should invest in maintaining reliable electricity services. The graph below shows that maintaining reliable electricity services is the number one priority for customers.
- Improved communications through pro-active measures like the MyPUC App, website tools and more consistent use of social media platforms, PUC has been able to get in front of issues (including outages) for a better overall customer experience. Customers can now access information on planned outages, news updates, changes in electricity rates, etc. on multiple platforms, thereby improving a customer's overall experience with PUC.

Building from the results of the first survey, the second survey (part two of two) was conducted in May-June 2022. 816 customers completed an online survey during a three-week time period between May 20th and June 10th 2022.

PUC should focus its priorities on delivering reasonably priced electricity prices and ensuring safe and reliable electricity services. Finding show that 92.15% of customers ranked either delivering reasonably priced electricity prices or ensuring safe and reliable electricity services as their top priority.

PUC should provide a variety of options for customers when accessing services, with a focus on online tools. In the graph below, customers noted that the MyPUC mobile app, the online self-serve options for managing their account and the availability of call centre staff are the most important options when accessing services.

PUC should provide both reliable information and services regarding the adoption of electric vehicles. In the graph below, 63.11% of customers stated they would like PUC to provide chargers for residential and commercial customers through rental or purchase programs, and 70.71% and 70.83% would like PUC to provide information on government incentives and more general reliable information on electric vehicles, respectively.

By having a presence in the community, developing, and improving upon communication channels and engaging customers through meaningful surveys, PUC has been able to effectively gather information from customers when making decisions. Improving upon the overall customer experience has been a top priority for PUC over the past five years, as demonstrated by the many innovations and improvements that have been made. Ensuring that customer voices are heard has pushed PUC leadership to be innovative and make smart decisions that are in the best interests of its customers, its employees, and its shareholder.

Appendix C - Scorecard Metrics

As part of its business plan PUC assess its performance in each of the OEB's performance outcomes over the last five years, how improvements are being made and its projections for continuous improvements. The following is a summary of the of PUC's 2021 OEB scorecard results for Customer Focus, Operational Effectiveness, Public Policy Responsiveness and Financial Performance.

Customer Focus

Service Quality

PUC continuously has met OEB approved target for New Services Connected on Time, Scheduled Appointment Met on Time, and Telephone Class Answered on Time. The table below summarizes the previous five (5) years historical results.

PUC is able to achieve high levels of compliance in new services connected on time due to its existing workflow process and expects this to continue into 2023 with a target for this metric of 90%.

Performance Year	New Residential/Small Business Services Connected on Time (Target: 90%)	Scheduled Appointments Met on Time (Target: 90%)	Telephone Calls Answered on Time (Target: 65%)
2021	97.60%	99.92%	71.13%
2020	100.00%	100.00%	68.88%
2019	100.00%	98.65%	72.43%
2018	99.12%	98.48%	77.70%
2017	96.67%	97.62%	79.88%

PUC has consistently met the number of scheduled appointments on time even with the increasing demand in the category. PUC will continue to excel in this category with a target of 90% in 2023.

PUC has had fluctuations in its results for telephone calls answered on time over the last five (5) years. PUC has been working on balancing the high demand in call volume while trying to maintain lower costs for its customers. PUC will continue to look to different avenues to communicate with its customers such as its Mobile App and Customer Chat function to help alleviate the high demand. PUC believes these initiatives will help alleviate the call volumes and improve PUC's results in this category over time. PUC 's target for this metric is 65%.

Customer Satisfaction

PUC's billing accuracy and first contact resolution has and continuous to achieve high level results with an average over 99%. PUC has been improving as of late on its customer satisfaction results. The below table summarizes the past five (5) years.

Performance Year	Billing Accuracy (Target: 98%)	First Contact Resolution	Customer Satisfaction Survey Results
2021	99.97%	99.63%	88%
2020	99.96%	99.76%	92%
2019	99.98%	99.82%	92%
2018	99.97%	99.80%	80%
2017	99.94%	99.74%	80%

PUC continues to strive for high performance in this category. PUC's target in 2023 is 98%, 99% and 85% respectively for billing accuracy, first contact resolution and customer satisfaction survey results.

Operational Effectiveness

Safety

Component A – Public Awareness of Electrical Safety

The Public Awareness of Electrical Safety measure is determined by public survey. The purpose of the survey is to monitor the effort and impact LDC's are having on improving public electrical safety for the Distribution Network. This public safety survey is intended to be conducted every two (2) years. The questions on the survey are standardized across the province.

PUC's third safety awareness survey was conducted in 2020 and resulted in a score of 85%. This was consistent with the previous Safety survey.

PUC continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness within PUC's service area. Through participation with the Association of Electrical Utility Professionals ("AEUSP"), PUC has contributed to the production of a series of electricity safety videos for television broadcast in various Ontario markets including its own service area.

PUC promotes electrical safety awareness in a variety of other forms. The importance of awareness of electrical hazards is conveyed throughout the community via safety related communications in newspapers, on the radio and at public events. Detailed hazard awareness presentations are made available to external contractors and joint use parties. In the broader community, public safety presentations are provided to elementary school students.

PUC's target for this category is 85% in 2023.

Component B – Compliance with Ontario Regulation 22/04

Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the Regulation requires the approval of equipment, plans and specifications and the inspection of construction before new assets are put into service. Component B includes an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. ESA evaluates these elements in order to determine the status of compliance.

For the past ten (10) years, PUC was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This success was achieved through PUC's strong commitment to safety and adherence to regulatory requirements, company policies and procedures.

PUC's target for this metric in 2023 is to have zero (0) safety non-compliance.

Component C – Serious Electrical Incident Index

Section 12 of Ontario Regulation 22/04 specifies the requirement to report to ESA any serious electrical incident of which they become aware within 48 hours after the occurrence. As assessed by ESA, in the 2021 reporting period, there were zero reportable serious electrical incidents.

PUC remains strongly committed to both the safety of staff and the general public. PUC regularly provides its customers with electrical safety information via its website, social media, and bill inserts. Additionally, PUC continues to make significant maintenance and capital infrastructure investments to enhance system safety and reliability.

PUC's target for this metric in 2018 is to have zero (0) serious electrical incidents reported.

System Reliability

In recent year PUC has seen a slight increase in its SAIDI and SAIFI results. Ongoing efforts to improve reliability, with a focus on effective maintenance activities and replacing aging infrastructure as indicated in PUC's Distribution System Plan, form part of PUC's strategies. PUC is also in the process of completing its Sault Smart Grid project installation, which once fully commissioned, is expected to help improve its reliability results. Since 10 substations and multiple circuits will be turned off at different stages of the construction project, it is anticipated that potential outages will impact more customers or may take longer to remediate, possibly resulting in a short-term reliability performance metric decline for the end of 2022 and the first quarter of 2023. Still in 2023, PUC's target for SAIDI is 1.62 and SAIFI is 1.42.

Performance Year	Average Number of Hours Power to Customer is Interrupted (SAIDI)	Average Number of Times Power to Customer is Interrupted (SAIFI)
2021	1.81	1.32
2020	2.12	1.74
2019	1.45	1.55
2018	1.27	1.28
2017	1.43	1.21

Asset Management

Distribution System Plan Implementation Progress

Consistent with industry best practices, PUC invests in its distribution system to ensure the safe and reliable delivery of electricity; and upgrades or replaces equipment to be able to serve customers on a continuous basis. The DSP, which covers the five-year period 2018-2022, was filed with the OEB as part of the 2018 Cost of Service Application. Prior to 2018, the OEB scorecard indicated 'In Progress' in the Performance Category of Asset Management to reflect this activity.

For years 2018 and onwards, PUC has established a metric which expresses performance by comparing the ratio of cumulative actual capital expenditures to date against cumulative planned capital expenditures to date for the period starting January 1, 2018 and ending on December 31 of each score card year. The ratio is then expressed as a percentage. The metric measures the LDCs overall performance completing capital work and includes all elements identified in the DSP inclusive of System Access, System Renewal, System Service and General Plant. The metric will include the cumulative expenditures for all previous years within the 5-year rate application period 2018-2022. So, for example the 2021 scorecard will show a cumulative percent expenditure for the first three years of the 2018-2022 rate application period. In effect, the metric gives a snapshot at the end of each year as to how closely the LDC is tracking to their plans in achieving the overall 5-year plan. PUC intends to file a new DSP covering the 2023 to 2027 period as part of its 2023 Cost of Service application.

The calculated value for this performance metric for 2021 is 104%. The year-over-year increase in the score reported for this metric (90% in 2020 versus 79% in 2019) - was attributable the planned rescheduling of a distribution station rebuild project (Substation 16) from 2019 to 2020/2021.

PUC has prepared a 2023-2027 DSP for its 2023 Cost of Service Application. As an ongoing target to meet the requirements of this DSP, PUC will continue to revisit and revise its capital spending based on system needs, cash flow forecasting, and the overall DSP plan itself.

Cost Control

Efficiency Assessment

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC ("PEG") on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs.

The table below summarizes the distribution of all distributors across the five (5) groupings for 2021:

Distribution of Distributors

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDCs in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	13
2	Actual costs are 10% to 25% below predicted costs	More Efficient	15
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	23
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	4
5	Actual costs are 25% or more above predicted costs	Least Efficient	2

Since PUC's last rebasing application in 2018, it has been working towards improvement in its efficiency performance. In 2019 PUC moved from group 4 to group 3. The table below shows PUC's actual vs predicted costs from the PEG Benchmarking model since 2017 and its resulting Group Ranking. In 2019, PUC moved from group 4 to group 3 and has remained there. PUC has completed a prediction of 2022 and 2023 based on its OM&A and Capital Budget for those respective years.

Year	Actual Costs	Predicted Costs	Cost Efficiency Assessment	3 Year Average	Stretch Factor Assisngment Group
2023 Projection	$32,966,739	$28,341,910	15.1%	6.0%	3
2022 Projection	$25,198,794	$24,943,099	1.0%	1.3%	3
2021 Actual	$23,585,229	$23,172,578	1.8%	2.8%	3
2020 Actual	$22,723,503	$22,474,823	1.1%	4.9%	3
2019 Actual	$23,450,122	$22,196,232	5.5%	8.3%	3
2018 Actual	$23,190,013	$21,371,771	8.2%	11%	4
2017 Actual	$22,600,176	$20,196,516	11.2%	13.8%	4

In 2023 PUC is projecting higher actual costs due to the reporting required for Substation 16 ICM and Sault Smart Grid ICM. Both ICM's are reported as capital expenditure in 2023 as per the RRR filing requirements and therefore inflate PUC's actual costs for that year. PUC expects its actual costs to stabilize in 2024, thus bringing back down its efficiency percentage. Additionally, it should be noted that PUC has additional costs and savings that are not accounted for in the PEG model.

Included in PUC's operating, maintenance and administrative expenses is a charge from PUC Services that is based on depreciating and financing of the vehicles, tools, computer equipment, office equipment etc. that is utilized to provide services to PUC. For utilities that own the vehicles and equipment to service their customers, these expenses are included in depreciation and financing costs. As the total costs would be the same, removing the depreciation and financing costs from PUC's operating costs would better align costs comparisons in the PEG model with other utilities.

In 2023, PUC's Sault Smart Grid will be live creating savings for customers that are not accounted for in this PEG model due to the unique, innovative nature of the project. Rather than SSG improving PUC's Financial Performance, it improves the financial performance for its customers, saving them an estimated 2.70% on the cost of power. Depending on what the actual cost of power in a year is, this will save customers approximately $1.7M.

After taken into consideration the influx in capital spending reported in 2023 from SSG and Substation 16, the charge from PUC Services to PUC and the SSG consumption savings for customers, the following table represents a revised calculation of actual costs and efficiency percentage.

Revised Cost Efficiency Percentage

Year	Actual Costs	Predicted Costs	Cost Efficiency Assessment	3 Year Average	Stretch Factor Assisngment Group
2023 Projection	$28,057,472	$28,341,910	-1.0%	0.6%	3

PUC's target is to remain in Stretch Factor Assignment Group 3.

Total Cost Per Customer

Total cost per customer is calculated as the sum of PUC's capital and operating costs, including certain adjustments to make the costs more comparable between distributors (i.e., under the PEG econometrics model), and dividing this cost figure by the total number of customers that PUC serves. PUC's cost performance results, from 2017 to 2021, have increased from $673 to $696 per customer. Overall, the company's total cost per customer has increased on average by 3.42% per annum over the period 2017 through 2021. For the period of 2017 to 2021, the total cost per customer on average has increased by approximately 0.84% per year. PUC will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. The company continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives that commenced in 2021 will continue in order to ensure customers have an opportunity to share their viewpoint on PUC's capital spending plans.

As with PUC's efficiency ranking above, this calculation uses PUC's actual costs in calculating the total cost per customer. In 2023, PUC is projecting an outlier year in actual costs due to the reporting of Substation 16 and Sault Smart Grid as Capital additions being added to rate base. This will inflate PUC's total cost per customer to $967 for 2023 and should return to more normalized levels in 2024. The table below shows PUC's historical results and projections for 2022 and 2023.

Year	total cost Per customer
2023 Projection	$967
2022 Projection	$741
2021 Actual	$696
2020 Actual	$673
2019 Actual	$697
2018 Actual	$690
2017 Actual	$673

After taken into consideration the influx in capital spending reported in 2023 from SSG and Substation 16, the charge from PUC Services to PUC and the SSG consumption savings for customers, the following table represents a revised calculation of total cost per customer.

Year	total cost Per customer
2023 Projection	$823

PUC's target is a total cost per customer of $823 after excluding costs for SSG, Substation 16, and non-operational costs discussed above.

Total Cost Per Km of Line

This measure uses the same total cost that is used in the cost per customer calculation above. The total cost is divided by the kilometers of line that the company operates to serve its customers. PUC's cost performance results, from 2017 to 2021, have increased from $30,541 to $31,915 per km of line.

PUC continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a low growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth. As a result, total cost per km of line has increased 4.50% since 2017 with the increase in capital and operating costs. For the period of 2017 to 2021, the total cost per km of line has increased by approximately 0.90% per year. A summary of the results is provided in table below.

Year	Total cost per Km of Line (revised)	Total cost per Km of Line
2023 Projection	$38,018	$42,252
2022 Projection	$34,145	$34,145
2021 Actual	$31,915	$31,915
2020 Actual	$30,791	$30,791
2019 Actual	$31,775	$31,775
2018 Actual	$31,338	$31,338
2017 Actual	$30,541	$30,541

PUC is projecting a spike in 2023 for the same reasons mentioned above. After adjusting for the increased costs due to SSG, Substation 16 and non operating costs discussed above, PUC is projecting a target of $38,018 in 2023.

Public Policy Responsiveness

Connection of Renewable Generation

- Renewable Generation Connection Impact Assessments Completed on Time

  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. PUC received no renewable generation CIA applications in 2021.

- New Micro-embedded Generation Facilities Connected on Time

  PUC connected three net-metered facilities in 2021 on time, in which the application and offer to connect for one were completed at the end of 2020 and two were completed fully in 2021.

Financial Performance

Financial Ratios

PUC's historical financial ratios for liquidity, Debt to Equity, and Deemed vs Achieve ROE is presented in the table below.

Performance Year	Liquidity: Current Ratio	Leverage: Total Debt to Equity Ratio	Profitability: Regulatory Return on Equity - Deemed	Profitability: Regulatory Return on Equity - Achieved
2021	0.8	2.10	9.00%	7.60%
2020	0.99	2.07	9.00%	8.75%
2019	0.94	2.03	9.00%	8.87%
2018	1.33	2.02	9.00%	4.25%
2017	1.62	2.04	8.98%	1.78%

PUC's current ratio has trended down in recent years, although this is misleading since it is being skewed by certain affiliate transactions. Specifically, the Current ratio is affected by how PUC funds its capital expenditures and the timing of financing arrangements. Going forward PUC will look at obtaining financing prior to year end which will shift more of the current liability to long term debt and improve the presentation of its current ratio. PUC's target for this category is one (1).

Debt to equity has remained at a level close to 2:1. PUC will be undergoing additional financing for the completion of the Sault Smart Grid project. This will increase debt to equity in 2023 to approximately 2.36. PUC expects this will fall below 2:1 starting in 2025. PUC's target for this category in 2023 is 2.36:1.

Return on Equity has stabilized just below the deemed ROE embedded in existing rates of 9% in recent years with a slight dip in 2021 due to the realization of COVID related expenses. PUC will be rebasing its rates in 2023 with rates effective May 1, 2023. As of August 2022, the deemed Return on Equity as part of the OEB's Cost of Capital Parameters is 8.66%. PUC expects the Cost of Capital Parameters to undergo an increase due to the rising cost of inflation. The OEB will issue its revised numbers in the fall of 2022 at which time PUC will revise its projected ROE.

APPENDIX C

Certificate of

Evidence

EXECUTIVE CERTIFICATION

EB-2022-0059

I, Robert Brewer, President and Chief Executive Officer of PUC Distribution Inc., hereby certify that, to the best of my knowledge:

a) the evidence filed in PUC's 2023 Cost of Service Application is accurate, complete and consistent with the requirements from Chapter 2 of the Board's *Filing Requirements for Electricity Distribution Rate Applications* last updated on April 18, 2022;

b) that robust processes and internal controls are in place for the preparation, review, verification and oversight of the deferral and variance account balances being disposed of, consistent with the certification requirement of Chapter 2 *Filing Requirements*; and

c) the evidence filed in support of this Application does not include any personal information, as identified in the certification requirements for personal information in accordance with Chapter 1 of the *Filing Requirements*.

Respectfully submitted,

Robert Brewer,
President & CEO

Dated at Sault Ste. Marie, Ontario, this 31st of August, 2022

APPENDIX D

OEB Decision ED-1999-0161 Decision on Distribution Assets

PUC

Ontario Energy Board
P.O. Box 2319
2300 Yonge Street
26th Floor
Toronto ON M4P 1E4
Telephone: (416) 481-1967
Facsimile: (416) 440-7656

Commission de l'Énergie de l'Ontario
C.P. 2319
2300, rue Yonge
26* étage
Toronto ON M4P 1E4
Téléphone: (416) 481-1967
Télécopieur: (416) 440-7656

Ontario

Licensing and Applications Branch

October 3, 2000

Mr. Ken Wallenius
General Manager & Secretary
Public Utilities Commission of the City of Sault Ste. Marie
765 Queen Street East
P.O. Box 9000
Sault Ste. Marie, Ontario
P6A 6P2

Dear Mr. Wallenius:

Re: Determination of Distribution Assets
ED-1999-0161

According to the information provided on the Information Request Form for the Public Utilities Commission of the City of Sault Ste. Marie (City of Sault Ste. Marie), Transitional Distribution Licence ED-1999-0161, City of Sault Ste. Marie has equipment that operates at voltages greater than 50 kV but that is used solely for the purposes of the distribution utility.

According to the *Ontario Energy Board Act* (the *Act*) such equipment, being over the 50 kV threshold, is defined as part of a transmission system; therefore, requiring the owner or operator to be licensed as a transmitter. However, under the s. 84 (a) of the Act, the Director of Licensing has the authority to determine that a part of a transmission system is a distribution system.

The Director, in accordance with s. 84 (a) of the *Act*, has determined that those assets above 50 kV held by City of Sault Ste. Marie form part of its distribution system. The City of Sault Ste. Marie Transitional Distribution Licence ED-1999-0161 is deemed to be an application for the end-state licence as specified under ss. 129 (5).

If there has been a change to the information provided regarding equipment at transmission-level voltage, please notify the Director.

If you have any questions concerning this matter, please contact Brian Hewson, Manager of Energy Licensing at 416 440-7628.

Sincerely,

Anne Powell
Director of Licensing

0761 (01/06)

APPENDIX E

PUC Distribution Inc. OEB 2021 Scorecard

Scorecard - PUC Distribution Inc.

7/15/2022

Performance Outcomes	Performance Categories	Measures		2017	2018	2019	2020	2021	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	**Service Quality**	New Residential/Small Business Services Connected on Time		96.67%	99.12%	100.00%	100.00%	97.60%		90.00%	
		Scheduled Appointments Met On Time		97.62%	98.48%	98.65%	100.00%	99.92%		90.00%	
		Telephone Calls Answered On Time		79.88%	77.70%	72.43%	68.88%	71.13%		65.00%	
	Customer Satisfaction	First Contact Resolution		99.74%%	99.80%	99.82	99.76	99.63			
		Billing Accuracy		99.94%	99.97%	99.98%	99.96%	99.97%		98.00%	
		Customer Satisfaction Survey Results		80%	80%	92	92	88			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	**Safety**	Level of Public Awareness		85.00%	85.00%	85.00%	85.00%	85.00%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C			C
		Serious Electrical Incident Index	Number of General Public Incidents	0	1	1	2	0			1
			Rate per 10, 100, 1000 km of line	0.000	0.135	0.135	0.271	0.000			0.076
	System Reliability	Average Number of Hours that Power to a Customer is Interrupted [2]		1.43	1.27	1.45	2.12	1.81			1.38
		Average Number of Times that Power to a Customer is Interrupted [2]		1.21	1.28	1.55	1.74	1.32			1.33
	Asset Management	Distribution System Plan Implementation Progress		In Progress	100%	79	90	104			
	Cost Control	Efficiency Assessment		4	4	3	3	3			
		Total Cost per Customer [3]		$673	$690	$697	$673	$696			
		Total Cost per Km of Line [3]		$30,541	$31,338	$31,775	$30,791	$31,915			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	**Connection of Renewable Generation**	Renewable Generation Connection Impact Assessments Completed On Time				100.00%					
		New Micro-embedded Generation Facilities Connected On Time								90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	**Financial Ratios**	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.62	1.33	0.94	0.99	0.80			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		2.04	2.02	2.03	2.07	2.09			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.98%	9.00%	9.00%	9.00%	9.00%			
			Achieved	1.78%	4.25%	8.87%	8.75%	7.60%			

1. Compliance with Ontario Regulation 22/04 assessed: Compliant (C); Needs Improvement (NI); or Non-Compliant (NC).
2. An upward arrow indicates decreasing reliability while downward indicates improving reliability.
3. A benchmarking analysis determines the total cost figures from the distributor 's reported information.

Legend:

5-year trend: up, down, flat

Current year: target met, target not met

2021 Scorecard Management Discussion and Analysis ("2021 Scorecard MD&A")

The link below provides a document titled "Scorecard - Performance Measure Descriptions" that has the technical definition, plain language description and how the measure may be compared for each of the Scorecard's measures in the 2021 Scorecard MD&A:

http://www.ontarioenergyboard.ca/OEB/_Documents/scorecard/Scorecard_Performance_Measure_Descriptions.pdf

Scorecard MD&A - General Overview

PUC Distribution Inc. ("PUC") distributes electricity to residences and businesses within the boundaries of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. PUC is committed to providing its customers with a safe and reliable supply of electricity while operating effectively and efficiently at an equitable cost. PUC continues to strive to meet distributor and Ontario Energy Board ("OEB") targets in customer focus, operational effectiveness, public policy responsiveness and financial performance.

PUC exceeded all performance targets in 2021. It was a year where resiliency, perseverance and hard work provided the momentum to achieve positive outcomes for PUC. In 2022, PUC will be undergoing a major improvement to its distribution system with the approval of Smart Grid, which will upgrade some of the existing infrastructure and help to improve reliability. PUC was successful in its cost controls, specifically in its Efficiency Assessment. PUC maintained its Incentive Rate Setting Stretch Factor Ranking assigned by the OEB due to its ability to keep costs in line with projections. Thus PUC remained in Group 3 cohort for its Stretch Factor Assignment ranking.

PUC strives to maintain or improve its overall scorecard performance by monitoring key performance measures throughout the year and addressing issues as they arise. PUC plans to undertake initiatives which will mitigate risks, allowing continued delivery of the current performance levels. In 2022, PUC will continue efforts to maintain a high level of achievement on the scorecard performance results, while continuing to focus on continuous improvement across all areas of its business.

Service Quality

- **New Residential/Small Business Services Connected on Time**

  The OEB's Distribution System Code (DSC) requires electricity distributors to connect a new service for customers (those utilizing connections under 750 volts) within five business days, 90% of the time. In 2021, PUC connected 250 eligible low-voltage residential and small business customers to its distribution system, exceeding the OEB target of 90% by connecting 97.60% of its requests on time.

  PUC is consistently able to achieve high levels of compliance in this area due to our existing workflow processes. Our commitment to customer care is demonstrated through staff education, customer engagement activities and the investigation of any opportunity for improvement.

- **Scheduled Appointments Met on Time**

  PUC strives to meet customers' meeting requests and comply with industry standards. The OEB's DSC requires that for appointments during regular business hours, the electricity distributor must offer a window of time that is no longer than four hours and must arrive within that window 90% of the time. In 2021, PUC scheduled 1,252 appointments with customers to complete customer requested work (e.g., meter installs/removals, service disconnects, reconnects, and meter locates.) PUC exceeded the OEB target by arriving at the scheduled appointments 99.92% of the time.

- **Telephone Calls Answered on Time**

  The OEB's DSC requires that during regular call centre hours, call centre staff must answer online calls within 30 seconds of receiving the call, 65% of the time. In 2021, PUC's Customer Experience Department received 41,886 calls from its customers. Of these calls, a Customer Care Representative answered the call within 30 seconds or less 71.13% of the time. This was an increase to the 68.88% in 2020.

  Although a combination of unprecedented challenges occurred in 2021 (e.g. work from home, increase in Ontario initiated programs, etc.) PUC exceeded the OEB target.

Customer Satisfaction

- **First Contact Resolution**

  PUC aims to address its customers' needs as quickly as possible and strives to resolve customer concerns and issues the first time the customer contacts PUC. The OEB requires electricity distributors to report on its success at meeting customers' needs the first time the electricity distributor is contacted.

  This metric is known as First Contact Resolution. PUC's First Contact Resolution was measured by tracking the number of electric related calls that were escalated to a Senior Customer Care representative, Supervisor, or Manager. This was accomplished by tracking two specific call types in our Customer Information System (CIS), which are queried to provide the number of customer concerns that were escalated.

  In 2021, PUC received 41,886 calls, of which 153 contacts were escalated to a Senior Representative or Supervisor. This resulted in a First Contact Resolution percentage of 99.63%. To establish the number of calls that were handled without escalation, the total number of calls that were escalated to a higher level of management was subtracted from the total number of calls received. However, it should be noted that First Contact Resolution can be measured in a variety of ways and PUC believes further regulatory guidance is necessary to achieve meaningful comparable information across electricity distributors.

- **Billing Accuracy**

  The OEB prescribes a measurement of billing accuracy which must be used by all electricity distributors. The measure has been defined as the number of accurate bills issued expressed as a percentage of total bills issued. In 2021, PUC issued approximately 370,843 bills and achieved an accuracy level of 99.97%. This score compares favourably to the prescribed OEB target of 98%. PUC continues to monitor its billing accuracy results and processes to identify opportunities for improvement.

- **Customer Satisfaction Survey Results**

  Engaging customers in a constantly changing energy environment is increasingly important. The OEB requires electricity distributors to measure and report customer satisfaction results at least every other year. In 2021, PUC did conduct a Customer Satisfaction Survey. PUC's Customer Satisfaction Survey score was 88%.

PUC engaged Utility PULSE (the electricity survey division of Simul Corporation) to conduct a bi-annual in-depth customer satisfaction telephone survey. There were 2,719 households and small business contacted and 401 completed interviews (85% residential & 15% commercial). The survey asks a core set of questions for overall satisfaction with PUC, reliability of service, outages, billing issues and corporate image. The overall scorecard combined results was an "A" rating which is in line with the reporting Ontario LDC average of "A".

Customer engagement provides feedback that is critical for PUC's long-term success and ensures customers are provided with services they value and the value they expect. The next survey will be conducted in 2023.

Safety

The Public Awareness of Electrical Safety measure (Component A) was introduced by the OEB in 2015 and focuses on the safety of the distribution system from a customer's point of view. The Electrical Safety Authority ("ESA") provides an assessment as it pertains to Component B – Compliance with Ontario Regulation 22/04 and Component C – Serious Electrical Incident Index.

- **Public Safety**
  - **Component A – Public Awareness of Electrical Safety**

The Public Awareness of Electrical Safety measure is determined by public survey. The purpose of the survey is to monitor the effort and impact LDC's are having on improving public electrical safety for the Distribution Network. This public safety survey is intended to be conducted every two (2) years. The questions on the survey are standardized across the province.

PUC's third safety awareness survey was conducted in 2020 and resulted in a score of 85%. This was consistent with the previous Safety survey.

PUC continues to look for every opportunity to communicate and engage with the public to promote electrical safety awareness in our service area. Through participation with the Association of Electrical Utility Professionals ("AEUSP"), PUC has contributed to the production of a series of electricity safety videos for television broadcast in various Ontario markets including its own service area.

Additionally, PUC promotes electrical safety awareness in a variety of forms. The importance of awareness of electrical hazards is conveyed throughout the community via safety related communications in newspapers, on radio and at public events. Detailed hazard awareness presentations are made available to external contractors and joint use parties. In the broader community, public safety presentations are provided to elementary school students.

- **Component B – Compliance with Ontario Regulation 22/04**

Ontario Regulation 22/04 establishes objective based electrical safety requirements for the design, construction and maintenance of electrical distribution systems owned by licensed distributors. Specifically, the Regulation requires the approval of equipment, plans and specifications and the inspection of construction before they are put into service. Component B is comprised of an External Audit, a Declaration of Compliance, Due Diligence Inspections, Public Safety Concerns and Compliance Investigations. ESA evaluates all these elements in order to determine the status of compliance.

For the past ten (10) years, PUC was found to be compliant with Ontario Regulation 22/04 (Electrical Distribution Safety). This success was achieved by PUC's strong commitment to safety and adherence to regulatory requirements, company policies and procedures.

- **Component C – Serious Electrical Incident Index**

Section 12 of Ontario Regulation 22/04 specifies the requirement to report to ESA any serious electrical incident of which they become aware within 48 hours after the occurrence. As assessed by ESA, in the 2021 reporting period, there were zero reportable serious electrical incidents.

PUC remains strongly committed to both the safety of staff and the general public. PUC regularly provides its customers with electrical safety information via its website, social media, and bill inserts. Additionally, PUC continues to make significant maintenance and capital infrastructure investments to enhance system safety and reliability.

System Reliability

The OEB requires the reporting of reliability data with respect to Major Events. Specifically, the data serves to a) adjust the reliability data to remove the impact of Major Events and b) require reporting of criteria to monitor the distributor's performance related to the Major Event. The 2021 Scorecard system reliability data excludes both Loss of Supply and Major Events.

A “Major Event” is defined as an event that is beyond the control of the distributor and is:

a) Unforeseeable; b) Unpredictable; c) Unpreventable; d) Unavoidable

Such events disrupt normal business operations and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers.

In 2021 there was one (1) major event day that occurred. The main cause of the major event day was Lightning.

- **Average Number of Hours that Power to a Customer is Interrupted**

  An important feature of a reliable distribution system is the quick recovery from power outages. Accordingly, electricity distributors must track the average length of time, in hours, that their customers experienced a power outage over the past year. This measure is known as the System Average Interruption Duration Index (“SAIDI”). In 2021, PUC did not meet its SAIDI performance target with a recorded SAIDI of 1.81, below the 1.38 target. Throughout the year, PUC encountered a single major event which was attributable to cause code 4-Lightning. PUC has staff on-call to respond to emergencies and restore power as quickly as possible in the case of unforeseen outages. Ongoing efforts to improve reliability, with a focus on effective maintenance activities and replacing aging infrastructure as indicated in PUC’s Distribution System Plan (DSP), form part of PUC’s strategies.

- **Average Number of Times that Power to a Customer is Interrupted**

  Another important feature of a reliable distribution system is reducing the frequency of power outages. Electricity distributors must track the number of times their customers have experienced a power outage over the past year. This measure is known as the System Average Interruption Frequency Index (“SAIFI”). In 2021, PUC met its performance target for the SAIFI. PUC’s SAIFI of 1.32 was below the target of 1.33. The main outage causes in 2021 were Defective Equipment, Adverse Weather and unknown causes that could not be identified following patrols and where circuits were re-energized. Ongoing efforts to improve reliability, including looking for mitigation approaches for the main outage causes and a focus on effective maintenance activities and replacing aging infrastructure as indicated in PUC’s DSP, form part of PUC’s strategies.

Asset Management

- **Distribution System Plan Implementation Progress**

  Consistent with industry best practices, PUC invests in its distribution system to ensure the safe and reliable delivery of electricity; and upgrades or replaces equipment to be able to serve customers on a continuous basis. The DSP, which covers the five-year period 2018-2022, was filed with the OEB as part of the 2018 Cost of Service Application. Prior to 2018, the OEB scorecard indicated ‘In Progress’ in the Performance Category of Asset Management to reflect this activity.

For years 2018 and onwards, PUC has established a metric which expresses performance by comparing the ratio of cumulative actual capital expenditures to date against cumulative planned capital expenditures to date for the period starting January 1, 2018, and ending on December 31 of each score card year. The ratio is then expressed as a percentage. The metric measures the LDCs overall performance completing capital work and includes all elements identified in the DSP inclusive of System Access, System Renewal, System Service and General Plant. The metric will include the cumulative expenditures for all previous years within the 5-year rate application period 2018-2022. So, for example the 2021 scorecard will show a cumulative percent expenditure for the first three years of the 2018-2022 rate application period. In effect, the metric gives a snapshot at the end of each year as to how closely the LDC is tracking to their plans in achieving the overall 5-year plan. PUC intends to file a new DSP covering the 2023 to 2027 period as part of its 2023 Cost of Service application.

The calculated value for this performance metric for 2021 is 104%. The year-over-year increase in the score reported for this metric (90% in 2020 versus 79% in 2019) - was attributable the planned rescheduling of a distribution station rebuild project (Substation 16) from 2019 to 2020/2021.

Cost Control

- **Efficiency Assessment**

The total costs for Ontario local electricity distribution companies are evaluated by the Pacific Economics Group LLC (“PEG”) on behalf of the OEB to produce a single efficiency ranking. The PEG econometrics model attempts to standardize costs to facilitate more accurate cost comparisons among distributors by accounting for differences such as the number of customers, treatment of high and low voltage costs, kWh deliveries, capacity, customer growth, length of lines, etc. All Ontario electricity distributors are divided into five groups based on the magnitude of the difference between their respective individual actual costs versus the PEG model predicted costs.

The following table summarizes the distribution of all distributors across the 5 groupings for 2021:

Group	Demarcation Points for Relative Cost Performance	Group Ranking	# of Ontario LDC’s in Group
1	Actual costs are 25% or more below predicted costs	Most Efficient	13
2	Actual costs are 10% to 25% below predicted costs	More Efficient	15
3	Actual costs are within +/-10% of predicted costs	Average Efficiency	23
4	Actual costs are 10% to 25% above predicted costs	Less Efficient	4
5	Actual costs are 25% or more above predicted costs	Least Efficient	2

In 2021, PUC remained in Group 3, average efficiency. PUC's 3-year average of actual-to-predicted costs dropped to 2.8% for 2019-2021. This was driven mainly by lower OM&A costs and capital spending in 2021. In 2021, PUC continued to have operations impacted by COVID, and as a result we expect to see increased spending in OM&A and capital in 2022.

- **Total Cost per Customer**

  Total cost per customer is calculated by PEG as the sum of PUC's capital and operating costs, including certain adjustments to make the costs more comparable between distributors, divided by the total number of customers that PUC serves. The cost performance result for 2021 is $696 per customer which is a 3.44% increase over 2020. On June 17, 2021 the OEB release the outcome of the Consultation titled "Regulatory Treatment of Impacts Arising from the COVID-19 Emergency" which provided further guidance on the use of the COVID DVA. Based on the guidance provided by the OEB in their report, PUC Distribution's costs in the COVID DVA account were ineligible for recovery and $597k was recognized as an expense in the 2021 results. This resulted in a higher total Cost per customer in 2021. In the absence of this, PUC's results would be $679 per customer which is slightly higher than the 2020 results.

  PUC will continue to replace aging distribution assets proactively in a manner that balances system risks and customer rate impacts. In addition, PUC continues to implement productivity and improvement initiatives to help offset some of the costs associated with future system improvement and enhancements. Customer engagement initiatives will continue in order to ensure customers have an opportunity to share their viewpoint on PUC's capital spending plans.

- **Total Cost per Km of Line**

  This measure uses the same total cost that is used in the Cost per Customer calculation above. The Total Cost is divided by the kilometers of line that the company operates to serve its customers. PUC's 2021 rate is $31,915 per Km of line, a 3.65% increase over 2020. As mentioned above, PUC's total costs increase because of an additional $597k that was recognized as an expense in the 2021 results. This resulted in a higher Total Cost per Km of Line. In the absence of this, PUC's results would be $31,107 total Cost per Km of line and only a 1.03% increase from 2020.

  PUC continues to experience a low level of growth in its total kilometers of lines due to a low annual customer growth rate. Such a flat growth rate has reduced the ability to fund capital renewal and increasing operating costs through customer growth.

Connection of Renewable Generation

- **Renewable Generation Connection Impact Assessments Completed on Time**

  Electricity distributors are required to conduct Connection Impact Assessments (CIAs) within 60 days of receiving authorization for their project from the Electrical Safety Authority. PUC received no renewable generation CIA applications in 2021.

- **New Micro-embedded Generation Facilities Connected on Time**

  PUC connected three net-metered facilities in 2021 on time, in which the application and offer to connect for one were completed at the end of 2020 and two were completed fully in 2021.

Financial Ratios

Financial Ratios are used to determine various aspects of a company's operating and financial performance. On June 17th, 2021, the OEB issued the Report of the Ontario Energy Board: Regulatory Treatment of Impacts Arising from the COVID-19 Emergency. As a result of this announcement, PUC made adjusting entries in 2021 relating to costs allocated to the Deferred Regulatory account in 2020 that were determined to be expense. PUC recorded COVID related lost revenue and expenses in 2021 that were from 2020 following the guidance of the OEB treatment. This impact affected the financial ratios in 2021.

- **Liquidity: Current Ratio (Current Assets/Current Liabilities)**

  As an indicator of financial health, a current ratio greater than 1 is considered good as it indicates that the company can pay its short-term debts and financial obligations. Companies with a ratio of greater than 1 are often referred to as being "liquid". The higher the number, the more "liquid" and the larger the margin of safety to cover the company's short-term debts and financial obligations.

  PUC's current ratio for 2021 was 0.80, a decrease of 0.19 from 2020.

- **Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio**

  The Total Debt to Equity Ratio measures the extent to which the assets of a company are financed by borrowing money. A debt-to-equity ratio of 1.00 means that half of the assets of a business are financed by debts and half by shareholders' equity. The OEB uses a deemed capital structure of 60% debt, 40% equity for electricity distributors when establishing rates. This deemed capital mix is equal to a debt to equity ratio of 1.5 (60/40).

  PUC’s leverage position has remained relatively consistent, at 2.09 in 2021 above the OEB’s target of 1.5. This indicates a debt-to-equity structure of 68% debt, 32% equity. PUC’s approach to managing its capital structure has served both it and its customers well in the past. Maintaining a higher debt to equity ratio enables PUC to fulfill capital and operating programs without impairing its ability to meet its financial obligations.

- **Profitability: Regulatory Return on Equity – Deemed (included in rates)**

  PUC’s current distribution rates were approved by the OEB and include an expected (deemed) regulatory return on equity of 9.00%. The OEB allows a distributor to earn within +/- 3% of the expected return on equity. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor’s revenue and cost structure by the OEB.

- **Profitability: Regulatory Return on Equity – Achieved**

  PUC’s achieved return in 2021 was 7.60% which is within the +/- 3% range allowed by the OEB. Productivity improvements and operational efficiencies continue to be a priority for the business. PUC will continue to seek process improvements, find efficiencies, and manage costs while delivering on the operational and capital programs. Going forward, PUC expects to maintain within +/- 3% range of the deemed regulatory return on equity.

Note to Readers of 2021 Scorecard MD&A

The information provided by distributors on their future performance (or what can be construed as forward-looking information) may be subject to a number of risks, uncertainties and other factors that may cause actual events, conditions, or results to differ materially from historical results or those contemplated by the distributor regarding their future performance. Some of the factors that could cause such differences include legislative or regulatory developments, financial market conditions, general economic conditions, and the weather. For these reasons, the information on future performance is intended to be management’s best judgement on the reporting date of the performance scorecard and could be markedly different in the future.

APPENDIX F

PUC Distribution

Inc Customer

Satisfaction Survey

PUC Distribution Inc.

21st Annual Electric Utility Customer Satisfaction Survey

UtilityPULSE

Summary

PUC

The purpose of this report is to profile the connection between PUC Distribution Inc. (PUC Distribution) and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information to support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis contained in this report is intended to capture the state of mind or perceptions about your customers' need and wants – the information contained in this report will help guide your discussions for making meaningful improvements.

This survey report is privileged and confidential material, and no part may be used outside of PUC Distribution Inc. without written permission from UtilityPULSE, the electric utility survey division of Simul Corporation.

All comments and questions should be addressed to:

Sid Ridgley, UtilityPULSE division, Simul Corporation

Phone: 905-895-7900 x 29

Email: **sridgley@simulcorp.com**

The Need for Credibility and Trust

Customers continue to be concerned about the costs of electricity today and what they might be in the future. In a separate study conducted August 2019, UtilityPULSE asked 1,000 Ontarians, *"How confident are you in the new Ontario Conservative government, elected in June 2018, to deliver the additional 12% reduction in electricity costs?"* Only 27% were very or somewhat confident, 53% were very or somewhat unconfident, and 14% were neither confident or unconfident. In follow-up questions, 38% agree the savings would be achieved by reducing customer service levels, and 34% agree savings would come from a delay in maintenance of the electricity system. These findings, coupled with a revamping of the Ontario Energy Board, tell us the industry has a believability issue, and that spells opportunity for PUC Distribution.

It is human nature to seek out support during times of disruption and uncertainty. Based on our 21 consecutive years of customer research, we believe Ontario LDCs are the entities best poised to provide that support.

Why?

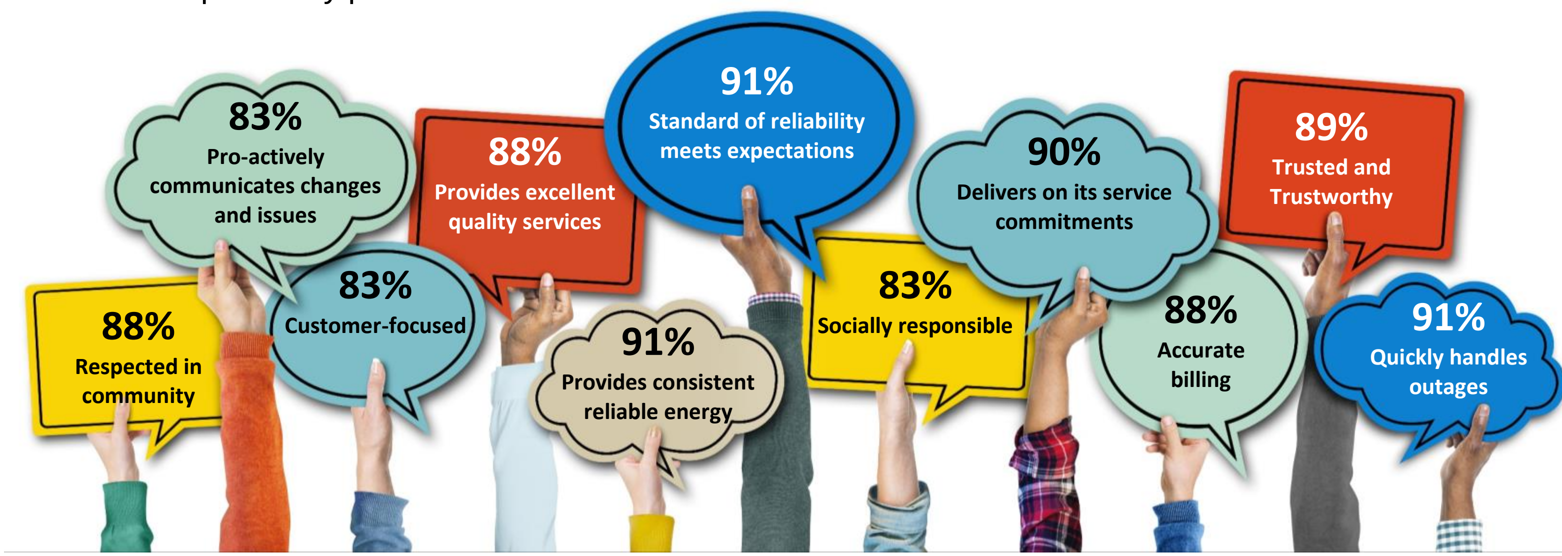
Credibility & Trust Index

PUC Distribution is trusted by its customers; 89% agree strongly or somewhat that the LDC is trusted and trustworthy. Your Credibility & Trust score is 87% while the Ontario benchmark is 84%, and the National benchmark is 84%.

Expectations from customers and other stakeholders continue to rise, which means, LDCs must continue to move forward to meet those expectations – and do so while mitigating the risks associated with maintaining a strong electricity delivery network. Being a monopoly isn't a license to stop improving.

Credibility & trust is a powerful currency for building relationships. Credibility & trust are outcomes based on what the LDC does, not what it might be doing. Hence a lot more pressure on the need for constantly communicating relevant information to the customer base.

Your survey was conducted from August 20 - September 21, 2019, and is based on 400 one-on-one telephone interviews with residential and small commercial customers who pay or look after the electricity bill. Also, survey findings for PUC Distribution are enhanced with the inclusion of data from our UtilityPULSE database and the independently produced Ontario and National Benchmarks.



Base: total respondents: Top 2 Boxes: "Strongly agree + agree"

Communication Score

We live in a world where polarized viewpoints are considered “normal,” and self-needs supersede social-needs. It is not that people don’t care about what is going on around them or how others may be impacted; they care more about what is happening or could happen to them first.

From a human nature point-of-view, self-interest leads to emotional reactions and decision-making. Even in a commodity purchase environment such as electricity, communicating reams of data and numbers won’t help the LDC get the support it needs to make changes. Communications cannot be an after-thought, it must be pro-active, and it must be delivered via multiple platforms.

Communication Score		
	Ontario LDCs	**PUC Distribution**
Communication Score	79%	82%

Base: An aggregate of respondents from 2019 participating LDCs / total respondents from the local utility

PUC Distribution received a respondent score of 83% for the attribute *“is pro-active in communicating changes and issues which may affect electric service.”*

Communication channels preferred by customers to receive notice about Billing Issue

UtilityPULSE database information tells us that the preferred channel for communications can change based on the type of issue which exists, e.g., a billing issue versus an unplanned outage issue. Two things we believe LDCs must be mindful of:

1. The preferred communication channel is determined by the customer, not by the LDC.
2. There is a higher expectation that the LDC will become more "outbound" communications driven.

PUC Distribution's customers' preferred or primary method for PUC Distribution to contact them about billing issues are as follows:

Preferred method of communication to receive notice of a Billing Issue

	Ontario LDCs	PUC Distribution
Telephone	54%	64%
Voice Mail	0%	3%
Text	8%	6%
Email	35%	26%
Don't know	1%	2%

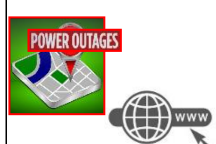
Base: An aggregate of respondents from 2019 participating LDCs / total respondents from the local utility

LDCs, for the most part, are primarily set up as "inbound" problem solvers and communicators. The notion or idea that the LDC needs to become more "outbound" with personalized channel communication is a challenge

from an organizational culture and operations perspective. Yet, if the LDC doesn't become more outbound driven, it will have to invest more into inbound methods for solving problems – which is extremely expensive.

Our data show "older" respondents have a heavier desire to communicate via the telephone, but youths, especially those in the 18-34 range, are far more comfortable getting and receiving information electronically. But preferences are changing. The UtilityPULSE database shows about 1 in 3 respondents in the 55+ age category prefer to receive notice about a billing issue via electronic means, while almost 2 in 3 respondents in the 18-34 age range prefer the electronic channels of email and text.

Communication during Unplanned Outages

Method of communication Customers prefer their LDC uses during an UNPLANNED OUTAGE							
Recorded Telephone Message or Call-in outage line	**Email Notice**	**Outage Map posted on the utility's website**	**Social Media**	**Text Message**	**Alert on mobile APP**	**Outage Map posted on mobile APP**	**SMART Assistant such as Alexa or Google**
							
17%	26%	8%	6%	31%	4%	3%	2%

Base: An aggregate of respondents from 2019 participating LDCs

Interesting to note, the UtilityPULSE database shows about 7 out of 10, 18 to 34-year-old respondents prefer the electronic outbound communication channels compared to about 5 out of 10, of the 55+ age group.

As it relates to inbound communications, respondents aged 18 to 34 are almost 3 times more likely to go to an outage map on a website than the 55+ age group. However, the 55+ age group is almost 5 times more likely to call into a toll-free outage line.

The Convenience of Services Score

We recommend that LDCs focus their investing on outbound communication channel technology and easy methods to look-up information or to get service because time-pressed customers appreciate when an organization is 'easy to do business with.' However, while some customers are comfortable with technology, they are not fully aware of what they can do or get online from the LDC website. Hence, it is extremely important to constantly and consistently communicate changes and enhances made. The UtilityPULSE database shows about 4 out of 10 respondents aged 55+ compared to 2 out of 10 for 18 to 34-year-old respondents answered, "Don't know" to the question about being satisfied with "the online self-serve options for requesting services."

Access to services		
Top 2 Boxes: 'very + somewhat satisfied'	**Ontario LDCs**	**PUC Distribution**
The availability of call-centre staff Monday to Friday	74%	74%
The 24/7 availability of system operators to respond to outages	75%	78%
The online self-serve options for managing your account	61%	57%
The online self-serve options for request services	53%	50%
The ability to walk in for customer service	n/a	74%

Base: An aggregate of respondents from 2019 participating LDCs / total respondents from the local utility
Hours: Ontario LDCs 8:30 am to 4:30 pm, PUC Distribution 9:00 am to 4:30 pm

Based on customer responses, PUC Distribution has rated 78% for Convenience of Services while Ontario LDCs' score remains unchanged from 2018, rated 79%.

The Core Responsibilities

Talk as we might about societal changes, the reality is, LDCs have a core responsibility that no other organization owns; the safe and reliable delivery of electricity. PUC Distribution survey respondents agree strongly + agree somewhat (Top 2 boxes), their LDC: Provides consistent, reliable electricity 91%, Quickly handles outages and restores power 91%, Accurate billing 88% and Makes electricity safety a top priority for employees, contractors, and the public 90%.

Issues: Billing and Blackouts, the "Killer B's"

As the province's interest shifts toward building a more efficient electric system capable of handling growing demand with smoother incorporation of renewable energy sources, the LDC's consistent communication about how/what you are doing to minimize risk factors and improve reliability in the electricity network, will increase the perception that the LDC is a credible organization.

Bills & Blackouts are the top two issues that cause the most disruption to customers. Our UtilityPULSE database shows 18% of respondents said they had a billing issue (Spring 2017) compared to about 8% in 2019. The drop is primarily the result of reduced prices and a better economy. In 2017, 88% of respondents' billing complaints were driven by concerns for high bills or rates.

Our database shows low-income customers (<$30,000 household) are about 35% more likely than high-income customers (>$75,000 household) to site high bills or to have a complaint about rates as their reason for a billing problem. At risk customers are 50% more likely to site high bills or have a complaint about rates than Secure customers.

Problems: Blackouts

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	PUC Distribution	National	Ontario
2019	40%	44%	45%

Base: total respondents

Problems: Billing issues

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	PUC Distribution	National	Ontario
2019	12%	9%	9%

Base: total respondents

Customer Service

While it is true, PUC Distribution receives good operational scores; it also has a responsibility to professionally and quickly deal with issues customers contact them about. In a complex electricity industry world, this puts additional strain on the skills and competencies of everyone who interacts with customers.

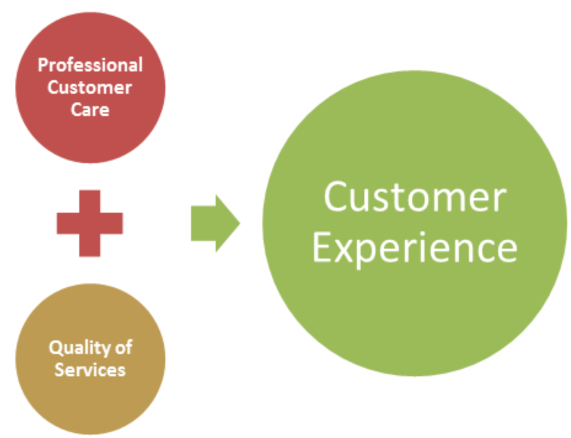
Satisfaction with Customer Service			
Top 2 Boxes: 'very + fairly satisfied'	**PUC Distribution**	**National**	**Ontario**
The time it took to contact someone	79%	69%	71%
The time it took someone to deal with your problem	73%	72%	70%
The helpfulness of the staff who dealt with you	76%	77%	78%
The knowledge of the staff who dealt with you	73%	74%	71%
The level of courtesy of the staff who dealt with you	79%	79%	77%
The quality of information provided by the staff who dealt with you	79%	75%	74%

Base: total respondents who contacted the utility; small data sample N=75

Customer Experience Performance rating (CEPr)

The truth is, your organization can be excellent at handling customer issues online, in-person, and on-the-telephone, with superb performance numbers. Yet, suffer in the area of corporate image.

While an excellent transaction today creates a positive experience, the perception created is, future transactions will be excellent too. Of course, a negative transaction creates the perception that future transactions will also be negative. The Professional Customer Care dimension of the CEPr represents the emotional side of an interaction, while the Quality of Service dimension represents the functional side of an interaction.



Customer Experience Performance rating (CEPr)			
	PUC Distribution	**National**	**Ontario**
CEPr: all respondents	87%	85%	86%

Base: total respondents

When the customer experience is positive and strong, the opportunity to build affinity/loyalty is great. When the experience is a negative one, customers often conclude the organization doesn't care. When a customer believes the organization doesn't care, outrage and anger are a very real possibility.

From an image point-of-view, PUC Distribution received very good scores for the attributes "keeps its promises to its customers and the community" →85% and "overall the utility provides excellent quality services" →88%.

Survey respondents gave PUC Distribution excellent operational and representative scores.

Core Operational Attributes			
	PUC Distribution	**National**	**Ontario**
Provides consistent, reliable energy	91%	91%	91%
Quickly handles outages and restores power	91%	88%	88%
Accurate billing	88%	88%	89%
Has a standard of reliability that meets expectations	91%	89%	90%
Makes electricity safety a top priority	90%	88%	89%

Base: total respondents with an opinion

Core Customer Service Quality Attributes			
	PUC Distribution	**National**	**Ontario**
Deals professionally with customers' problems	85%	85%	84%
Is 'easy to do business with'	86%	83%	83%
Customer-focused and treats customers as if they're valued	83%	82%	80%

Base: total respondents with an opinion

Customer Centric Engagement Index (CCEI)

A quick search on the internet will reveal many different definitions for the words "customer engagement." While there may be differences, the common theme is how UtilityPULSE defines CE, which is, "*Customer engagement is the emotional connection achieved by the ongoing interactions between a customer and the organization."*

The goal is to help customers:

- feel valued as a customer,
- appreciate being connected to a respected and trusted company and,
- have confidence the company will adapt well to changes in customer expectations.

As a reader, what you may not know is, Secure customers, demonstrate much higher levels of engagement than customers who are At Risk. It is much easier to gain support for changes from highly-engaged and Secure customers than from those who are not engaged and virtually hate the LDC. PUC Distribution has scored well on this index.

Utility Customer Centric Engagement Index (CCEI)			
	PUC Distribution	**National**	**Ontario**
CCEI	87%	83%	83%

Base: total respondents

Customer Satisfaction

As stated in previous reports, by itself, this metric is not enough to gain a picture of how well an LDC is doing, but it is a measure about whether the LDC is doing the job of taking care of customers as expected. However, without satisfaction, there is no gateway to loyalty.

The “initial” satisfaction score is meant to capture a “top-of-mind” satisfaction rating, and it is the first question in the survey (after qualifying the respondent). Asking the general satisfaction question at the start of the survey avoids bias, and we obtain a spontaneous rating.

Towards the end of the survey, we ask the satisfaction question again, i.e., “now that we’ve been talking about your electric utility for a while, how satisfied are you?”

That is, once the respondent has been asked about bills, blackouts, and various attributes of the LDC, we gain what is called a more considered (or conditioned) response. Ideally, we like to see the PRE and POST Satisfaction scores as being quite similar, i.e., +/- 2 points.

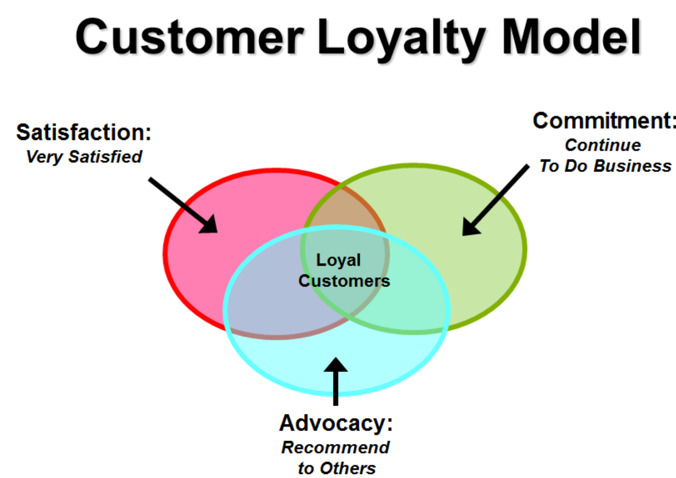
SATISFACTION SCORES – Electricity customers' satisfaction			
Top 2 Boxes: 'very + fairly satisfied'	**PUC Distribution**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	94%	93%	92%
POST: End of Interview	92%	93%	92%

Base: total respondents

The real prize is in the development of a relationship with customers. More good things exist when a customer has a high affinity for the LDC than when they dislike it. At Risk customers are more likely to complain than other customers when there are issues. Secure customers are more likely to support the direction of their LDC.

Loyalty Groups – Customer Affinity

For electric utilities, customer affinity is an attitudinal metric, not a behaviourial metric (as it would be for private industry). None-the-less, customers do feel some level of connection with their utility. There are customers who truly dislike and disrespect their utility, and there are those who feel connected to their utility. Interestingly At Risk customers seem to have more outages and more billing problems AND are more likely to contact the utility when they have a problem.



Customer Loyalty Groups				
	Secure	Favorable	Indifferent	At Risk
PUC Distribution	28%	22%	43%	8%
National	27%	17%	49%	7%
Ontario	27%	16%	48%	9%

Base: total respondents

Customer Advocacy

Electricity customers' loyalty – … is a company that you would recommend to a friend or colleague			
	PUC Distribution	National	Ontario
Top 2 boxes: 'Definitely + Probably' would recommend	78%	77%	74%

Base: total respondents

Customer Commitment

Electricity customers' loyalty – … Is a company that you would like to continue to do business with			
	PUC Distribution	National	Ontario
Top 2 Boxes: 'Definitely + Probably' would continue	84%	83%	82%

Base: total respondents

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide electric utilities with a snapshot of performance – on the things customers deem to be important.

PUC Distribution's UtilityPULSE Report Card®

Performance

	CATEGORY	PUC Distribution	National	Ontario
1	**Customer Care**	**A**	**B+**	**B+**
	Price and Value	B+	B+	B+
	Customer Service	A	A	A
2	**Company Image**	**A**	**A**	**A**
	Company Leadership	A	A	A
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A+	A	A
	OVERALL	**A**	**A**	**A**

Base: total respondents

Looking to the future, where to from here?

Being future-oriented is an important dimension of customer engagement.

The following data, extracted from the UtilityPULSE database, is offered as a source of input for making priority planning decisions. The high priority items are: *'Pro-actively maintaining and upgrading equipment,' 'Reducing response times to outages,'* and '*Investing more in the electricity grid to reduce outages and to increase reliability and safety'* and '*Investing more in projects to reduce the environmental impact of the utility's operations.'*

Priority Planning within the next 5 years	
Top 2 Boxes: 'very high + high priority'	**Ontario LDCs**
Pro-actively maintaining and upgrading equipment	88%
Reducing response times to outages	80%
Investing in projects to reduce the environmental impact of the utility's operations	77%
Investing more in the electricity grid to reduce outages	74%
Educating customers about energy conservation	73%
Investing more in tree trimming to help reduce the number of outages	68%
Educating the public as it relates to electricity safety	68%
Burying overhead wires	54%
Providing sponsorships to local community causes	49%
Making better use of social media (such as Twitter, Facebook, etc.)	49%
Developing a SMART phone application to allow you to view usage and pay your bill	47%
Providing more self-serve services on the website	42%

Base: An aggregate of respondents from 2019 participating LDCs

Paying for electricity

For 21 years, UtilityPULSE research shows ‘ability to pay’ as having an exceptionally strong correlation to satisfaction. For example, the UtilityPULSE database from Fall 2019, based on over 7,000+ interviews, shows a 10% lower satisfaction level for those who say paying for electricity is “often a problem” versus those who say, “not a worry.” The good news for the industry as a whole is, the number of respondents who answered, “often a problem” during the Fall 2019 interviews is about 5% lower than Spring 2017 levels. For PUC Distribution, 9% of respondents identified themselves as a person who finds paying their bill was “often a problem” versus 69% who claimed to pay for electricity was “not a worry.” Despite reliability, operational efficiency, customer care professionalism, or a strong brand, for the LDC, ‘ability to pay’ is a major factor in determining a customer’s perception of LDC performance.

Is paying for electricity a worry or a major problem?

	Not a worry	Sometimes	Often	Depends
PUC Distribution	69%	20%	9%	0%
National	74%	18%	6%	0%
Ontario	72%	19%	7%	6%

Base: total respondents

It is important to note, every age category, every income level, every kWh usage level, has respondents who identified themselves as people who find paying for electricity is “often a problem.”

Numbers at a Glance for 2019

	PUC Distribution	National	Ontario
Customer Satisfaction: Initial	94%	93%	92%
Customer Satisfaction: Post	92%	93%	92%
Communication Score	82%	--	79%
Overall Satisfaction with the most recent experience	79%	81%	79%
Convenience of Services Score	78%	--	79%
Customer Experience Performance Rating (CEPr)	87%	85%	86%
Customer Centric Engagement Index (CCEI)	87%	83%	83%
Credibility & Trust Index	87%	84%	84%
UtilityPulse Report Card©	A	A	A

While the customer base is concerned about costs and rising costs, we believe the customer base is becoming more vocal about what they are looking for from their LDC. For example, data from the UtilityPULSE database shows a 21% increase in the number of respondents providing suggestions Fall 2019 versus 2017. Suggestions which have almost doubled in frequency over the last two years include: *"Better communications"; "Provide more energy conservation info" [though no longer a responsibility of the LDC]; "Better reliability/less outages"' and "Better information on outages"* and our favourite *"Am satisfied, keep up the good work."*

Where to from here?

We believe that LDCs, like PUC Distribution, must promote and manage their public image. We know this because the Company Image portion of the UtilityPULSE Report Card® now represents over a 25% weighting for respondents versus a 15-17% rating when first published. Of the many items which can affect perceptions about an image, there are two which are of significance for impacting your LDC's image. Factor number one is to recognize that every customer touchpoint has the power to affect perception, and factor number two is, every employee or representative of PUC Distribution has a role to play in influencing the image of the LDC. After-all, PUC Distribution remains what we call an influential brand company.

We also know from the data that respondents for PUC Distribution who said their problem was solved had a 93% level of satisfaction, while those who said their problem wasn't solved was 65%. Quickly solving problems requires two things: (1) Processes have to be easy and fast, and (2) Employees need to be empowered – and expected --- to act. What you may not know is, employee empowerment is a huge factor for increasing employee engagement.

Based on the last few years, data also shows there are noticeable shifts away from using the telephone as the exclusive method for solving problems or getting service towards more of the electronics methods. The good news is, the shift will help the organization be more efficient, the bad news is, the LDC cannot abandon the telephone, and it must recognize that calls coming in will be more complex than in the past. The electronic methods typically help customers handle simpler requests, while people handle more complex ones. The pace for moving towards more electronic methodologies does vary by several factors, such as age, access to the internet, comfort with technology, and speed of the internet. As a rule of thumb, LDCs in larger communities need to move at a faster pace adopting technology than LDCs in rural communities.

This report started by talking about trust and credibility and its importance to customers in a world of uncertainty. High levels of trust and credibility mean high levels of affinity (loyalty) to PUC Distribution. But why should an LDC care about this, when a customer can't leave? From a satisfaction point-of-view, those who give high recommendation scores had a satisfaction score of 97% versus 78% for those with a low recommendation score. Those with high recommendation scores experience fewer outages, are less likely to contact the LDC about the outage, have fewer billing problems, and again less likely to contact the LDC about the billing issue.

The insight here is this. Satisfaction scores are affected by transactions, essentially the tangible side of service delivery. Transactions, whether good or bad, create a foundation for affinity (loyalty) to occur. Perceptions about trust and credibility are intangible and based on how a person feels.

The Ontario government hasn't been clear about how the additional 12% reduction in costs will be achieved. And, we have an Ontario Energy Board in transition. While LDCs may not have much influence over these two items, what we do know is PUC Distribution, can influence how the organization is seen by its customers and other stakeholders. We recommend ensuring the topic of customer care and the responsibility for providing excellent care, is on the meeting agendas for every department.

Sid Ridgley

Simul/UtilityPULSE
Email: sridgley@simulcorp.com

November 2019

Good things happen when workplaces work. You'll receive both strategic and pragmatic guidance about how to improve Customer satisfaction & Employee engagement with leaders who lead and a front-line which is inspired. We provide training, consulting, surveys, diagnostic tools, and keynotes. The electric utility industry is a market segment we specialize in. Both large and small utilities have received actionable insights. For 21 years, we have been talking to 1000's of utility customers in Ontario and across Canada, and we have expertise which is beneficial to every utility.

Culture, Leadership & Performance – Organizational Development	**Focus Groups, Surveys, Polls, Diagnostics**	**Customer Service Excellence**
Leadership development	Diagnostics, ie. Change Readiness, Leadership Effectiveness, Managerial Competencies	Service Excellence Leadership
Strategic Planning	Surveys & Polls	Telephone Skills
Teambuilding	Customer Satisfaction and Loyalty Benchmarking Surveys	Customer Care
Organizational Culture Transformation	Organization Culture Surveys	Dealing with Difficult Customers

Benefit from our expertise in Customer Satisfaction, Leadership Development, Strategy development or review, and Front-line & Top-line driven-change. We're experts in helping you assess and then transform your organization's culture to one where achieving goals while creating higher levels of customer satisfaction is important. Anyone can present data or design programs – we believe having an understanding of the industry before doing so is crucial. Call us when creating an organization where more employees satisfy more customers more often, is important.

Your personal contact is:

Sid Ridgley, CSP

Phone: (905) 895-7900 x 29 E-mail: sridgley@simulcorp.com

PUC Distribution Inc.

23rd Annual Electric Utility Customer Satisfaction Survey

UtilityPULSE

Summary

PUC

The purpose of this report is to profile the connection between PUC Distribution Inc. (PUC Distribution) and its customers.

The primary objective of the Electric Utility Customer Satisfaction Survey is to provide information to support discussions about improving customer care at every level in your utility.

The UtilityPULSE Report Card® and survey analysis in this report are intended to capture the state of mind or perceptions about your customers' need and wants – the information in this report will help guide your discussions for making meaningful improvements.

All comments and questions should be addressed to:

UtilityPULSE division, Simul Corporation

Sid Ridgley	David Malesich
President	Chief Research Officer
Email: sridgley@simulcorp.com	Email: david@utilitypulse.com

Continued Satisfaction and Rise of Increased Digital Communication

Nearly two years ago, the world was caught off-guard by the COVID-19 pandemic. While it may not be over quite yet, there seems to be light at the end of the tunnel, and a "new normal" appears to be emerging. There was fallout in many industries, but the pandemic has also brought about new changes to how the world conducts its business. Face-to-face communications and even telephone have decreased as more and more people opt to serve themselves online. Comfort and willingness to make purchases online, conduct online banking, and find answers to frequently asked questions have grown across the board.

Although e-commerce growth might not be as sky-high in 2020/21, online activities will continue to expand and accelerate far more than they did before pandemic-driven shutdowns and social distancing. Businesses have been more cognizant of online growth and technologies are being improved to meet the rising demand. The surge in accelerated digital transformation is expected to continue throughout the recovery from COVID-19, and electricity customers are no exception to this overall trend. Compared to before the pandemic, more electricity customers than ever before want to communicate via electronic means (e.g., email, text) with their utility. For example, customer preference for an email or text notification for an unexpected outage has grown by over 50% from 2019.

The sped-up transition to a digital world was not expected and not without its challenges. Companies, including utilities, have been forced to make changes to their websites and ensure that they can meet customers' changing needs and demands. Pre-authorized automated payments and e-billing have also increased in importance. Many digital options that were once considered 'nice to have' options have become widely expected standards. "Inbound" methods of communication are very expensive, so although challenging, especially at an accelerated pace, ensuring an effective self-service strategy can help reduce costs and ensure customers are satisfied.

Customers are showing increased comfort levels with technology, but now they are not always knowledgeable about what they can do or get online from their LDC website. Any changes or enhancements should be consistently communicated as well as be easy to navigate and understand.

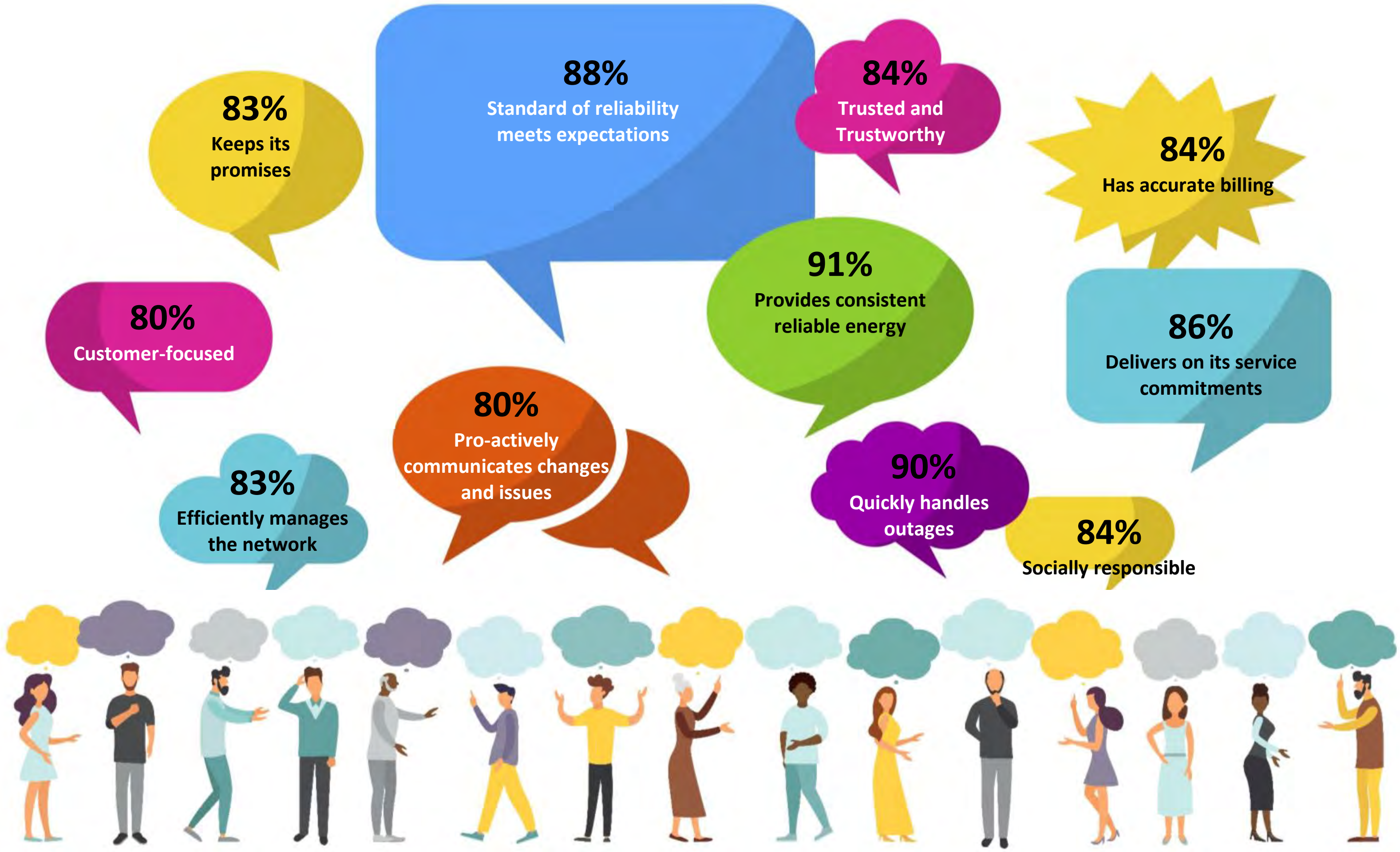
To better understand the self-service impact on utilities and track this metric going forward, a new question was added this year: "Before contacting your utility, did you visit the utility website to try to resolve your issue on your own, or to get more clarity on the issue before contacting the utility?" Prior to contacting the utility, 35% of PUC Distribution's customers visited the website first to try to resolve their issue on their own or get more clarity.

Visited website to try to resolve issue on own, or get more clarity, before contacting utility

	PUC Distribution	UP Database
Yes	35%	41%
No	65%	58%

Base: total respondents; small data sample; total respondents from the 2021 UtilityPULSE Database

The "COVID halo" continues. Scores were high last year, and people's utilities were one less worry on their plates during a terrible year. Scores remain high, which is very encouraging; for example, PUC Distribution's satisfaction score is 91%, and 'delivers on its service commitments to customers' is 86%.



Base: total respondents with an opinion

Going forward, we recommend continuing your efforts toward improving online ease and contactless self-service strategies, which are necessary to maintain a positive customer experience. Despite an appetite for more self-service, this does not mean the death of traditional forms, such as telephone. What is continually changing— are the many ways in which utilities can engage with their customers. Therefore, utilities will have to offer a wide mix of options to satisfy a customer base that increasingly wants the flexibility to interact with their utility based upon their preferences and situation. The result of all of this technological advancement is that customers are more informed and connected than ever before. Customer engagement is no longer characterized by one-way, utility-initiated communication. It's now a dynamic, multi-channel, two-way communication stream.

Customer Centric Engagement Index (CCEI)

Customer engagement is the emotional connection achieved by the ongoing interactions between a customer and the organization. Highly engaged customers are far more likely to support the LDC as it responds to changes than customers with little-to-no engagement. Highly engaged customers are less likely to complain publicly about disappointing shopping experiences, choosing to resolve issues with the company directly.

Utility Customer Centric Engagement Index (CCEI)

	PUC Distribution	National	Ontario
CCEI	83%	83%	82%

Base: total respondents

PUC Distribution has scored well on this index.

The Core Responsibilities

Survey respondents gave PUC Distribution excellent operational and representative scores.

Core Operational Attributes			
	PUC Distribution	**National**	**Ontario**
Provides consistent, reliable energy	91%	90%	90%
Quickly handles outages and restores power	90%	87%	87%
Has accurate billing	84%	87%	88%
Has a standard of reliability that meets expectations	88%	88%	88%
Makes electricity safety a top priority	90%	88%	89%

Base: total respondents with an opinion

Core Customer Service Quality Attributes			
	PUC Distribution	**National**	**Ontario**
Deals professionally with customers' problems	85%	84%	84%
Is 'easy to do business with'	85%	84%	84%
Customer-focused and treats customers as if they're valued	80%	79%	79%

Base: total respondents with an opinion

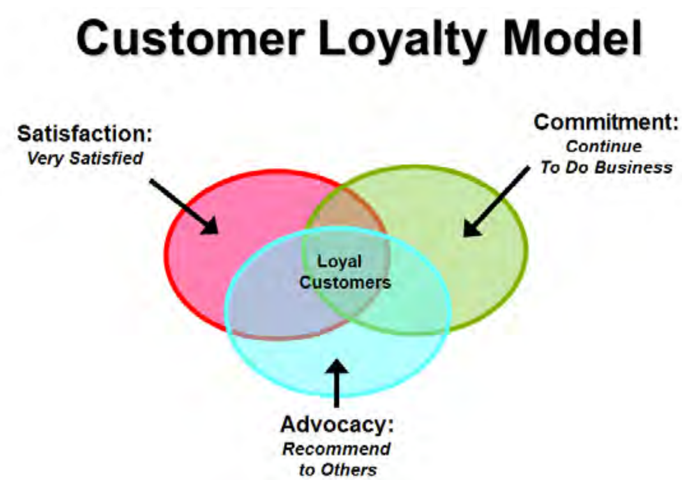
Customer Satisfaction

Measuring satisfaction is the bedrock, or starting point, for the creation of loyal customers. One must do the job as expected before there is an opportunity to emotionally connect in a positive way hence the need to focus on the overall customer experience. Customer satisfaction is an effectiveness measure (not an efficiency measure) on the historical relationship or delivery of services to customers.

SATISFACTION SCORES – Electricity customers' satisfaction			
Top 2 Boxes: 'very + fairly satisfied'	**PUC Distribution**	**National**	**Ontario**
PRE: Initial Satisfaction Scores	91%	94%	93%
POST: End of Interview	88%	93%	92%

Base: total respondents

When it comes to the question of satisfaction, UtilityPULSE has designed the survey so that customers are asked twice, once at the beginning – this is to garner first impressions and set the tone for the survey, and again at the end – because now the respondent has context of what is being asked and is more aptly ready to address it in an informed state of mind.



Loyalty Groups – Customer Affinity

Customer loyalty (affinity) is an intangible asset with positive consequences or outcomes associated with it, no matter the industry. Data shows that Secure customers have fewer outages and billing issues than At Risk customers, i.e., those that hate the utility. In private industry, Loyalty is a behavioural metric; in a monopoly, it is an attitudinal metric.

Customer Loyalty Groups

	Secure	Favorable	Indifferent	At Risk
PUC Distribution	28%	18%	44%	9%
National	29%	17%	47%	7%
Ontario	28%	16%	48%	8%

Base: total respondents

What is the importance of Net Supporter Score™ [NSS] for LDC's?

The NSS is a metric which measures how likely customers could ***support*** policy changes, actions, programs, or service changes or enhancements the LDC wishes to make. The NSS is a metric developed to help the organization, and its people, continue on a path of improving customer experiences, whether those experiences are in-person, over the telephone, online, or a combination. In a nutshell, the NSS reflects the net number of customers who have confidence in the LDC to continue to serve in their best interests.

Net Promoter Score™ (NPS)

The Net Promoter Score™ (NPS) is a popular metric that measures how likely customers are to recommend a business's products and services. Your NPS score, when compared to the benchmarks, can provide some insight into the affinity level of survey respondents towards your brand image. The NPS metric was developed by and is a registered trademark of Fred Reichheld, Bain & Company, and Satmetrix in 2003.

PUC Distribution has a Net Supporter Score™ (NSS) of 19%**.** The Ontario benchmark is 20%, and the UtilityPULSE database average is 26%.

Net Supporter Score™ (NSS)			
	Opportunity Range <20%	**Good Range 20-40%**	**Very Good Range 40+%**
PUC Distribution	19%	--	--
Ontario Benchmark	--	20%	--

Base: total respondents; range bands represent 2021 data and can change year-to-year

PUC Distribution has a Net Promoter Score™ (NPS) of 27%**.** The Ontario benchmark is 24%, and the UtilityPULSE database average is 35%.

Net Promoter Score™ (NPS)			
	Opportunity Range <5%	**Good Range 5-25%**	**Very Good Range 25+%**
PUC Distribution	--	--	27%
Ontario Benchmark	--	24%	--

Base: total respondents; range bands represent 2021 data and can change year-to-year

Issues: Billing and Blackouts, the "Killer B's"

The reliable and efficient delivery of electricity to homeowners and businesses is an essential service – especially during the personal and professional challenges of the past couple of years. Customers are comforted by the fact that standards for keeping the lights on and getting them up and running quickly have not deteriorated.

Problems: Blackouts

Percentage of Respondents indicating that they had a Blackout or Outage problem in the last 12 months			
	PUC Distribution	**National**	**Ontario**
2021	38%	39%	36%

Base: total respondents

Inaccurate bills cause angst and, in some cases, anger, which is why accurate billing remains an important service imperative for all utilities. PUC Distribution performs billing well despite the number of changes in pricing, including the need to communicate about various financial support options.

Problems: Billing issues

Percentage of Respondents indicating that they had a Billing problem in the last 12 months			
	PUC Distribution	**National**	**Ontario**
2021	11%	4%	6%

Base: total respondents

Communication channels preferred by customers to receive notice about Billing Issues (Other than payments owed)

UtilityPULSE database information tells us that the preferred channel for communications can change based on the type of issue, e.g., a billing issue versus an unplanned outage issue. Two things we believe LDCs must be mindful of:

1. The preferred communication channel is determined by the customer, not by the LDC.
2. There is a higher expectation that the LDC will become more "outbound" communications driven.

PUC Distribution's customers' preferred or primary method for PUC Distribution to contact them about billing issues (other than payments owed) are as follows:

Preferred method of communication to receive notice of a Billing Issue (Other than payments owed)		
	PUC Distribution	**Ontario LDCs**
Telephone	59%	45%
Voice Mail	1%	1%
Text	10%	10%
Email	27%	41%
Don't know	2%	1%

Base: total respondents / An aggregate of respondents from 2021 participating LDCs

LDCs, for the most part, are primarily set up as “inbound” problem solvers and communicators. The notion or idea that the LDC needs to become more “outbound” with personalized channel communication is a challenge from an organizational culture and operations perspective. Yet, if the LDC doesn’t become more outbound driven, it will have to invest more into inbound methods for solving problems – which is extremely expensive. As mentioned, increased focus on website design and self-service strategies will help alleviate potential future costs and is on trend to customer expectations.

Our data show “older” respondents have a heavier desire to communicate via the telephone, but youths, especially those in the 18-34 range, are far more comfortable getting and receiving information electronically. Preferences are changing and will continue to change as a result of previous pandemic-driven lockdowns and increased social distancing. The UtilityPULSE database shows about 1 in 3 respondents in the 55+ age category prefer to receive notice about a billing issue via electronic means. In comparison, almost 2 in 3 respondents in the 18-34 age range prefer the electronic channels of email and text.

Communication during Unexpected Outages

In times of emergency, be they extreme weather events or major equipment failures that cause blackouts and unplanned outages, customer communication can help customers understand what to expect next and when disrupted electricity service might be restored. Early and effective communication helps increase confidence in and credibility of the electricity service provider.

Respondents were asked the preferred communication channel PUC Distribution should use ***during an <u>unexpected</u> outage.*** Base: total respondents / An aggregate of respondents from 2021 participating LDCs

Preferred communication channel LDC should use during an UNEXPECTED Outage		
	PUC Distribution	**Ontario LDCs**
Text message alert	48%	49%
Recorded telephone message alert	35%	29%
Email alert	31%	38%
Social media alert on Twitter or Facebook, etc.	20%	14%
Outage map on utility's website	18%	18%
A toll-free outage line	16%	12%
Mobile APP alert	16%	15%
Outage map posted on mobile APP	0%	2%
Smart assistant alert such as Alexa or Google	0%	1%

Communication during <u>Planned Outages</u>

Respondents were asked the preferred communication channel PUC Distribution should use ***during a planned outage;*** times when the utility needs to undertake work on their network (poles, wires, meters, transformers, substations, etc.) to maintain a safe and reliable supply.

Preferred communication channel LDC should use during a PLANNED Outage		
	PUC Distribution	**Ontario LDCs**
Email alert	40%	47%
Recorded telephone message	38%	25%
Text message alert	37%	39%
Hand delivered notice	25%	20%
A toll-free outage line	16%	12%
Social media alert on Twitter, Facebook, etc.	16%	12%
Mobile APP alert	16%	13%
Other	16%	1%
Outage map on the utility's website	15%	15%
Outage map on mobile APP	12%	11%
Email invite that syncs to your calendar with the outage duration	0%	0%

Base: total respondents / An aggregate of respondents from 2021 participating LDCs

Communication Score

Customers expect that the companies they deal with will be "pro-active" communicators. They know they don't know everything, but they are hopeful that the companies they deal with will provide them with timely information. The reality is, Ontario LDCs have been pro-active communicators over the past couple of years.

PUC Distribution received a respondent score of 80% for the attribute *"is pro-active in communicating changes and issues which may affect your electricity service."*

Communications cannot be an afterthought; they must be pro-active and delivered via multiple platforms. Based on customer responses, PUC Distribution has achieved a **Communication Score** of 78%.

The Convenience of Services Score

We recommend that LDCs focus their investing on outbound communication channel technology and easy methods to look-up information or to get service because time-pressed customers appreciate when an organization is 'easy to do business with' – on this attribute, PUC Distribution received a respondent score of 85%.

However, while some customers are comfortable with technology, they are not fully aware of what they can do or get online from the LDC website. Hence, it is crucial to constantly and consistently communicate changes and enhancements made.

Access to services		
Top 2 Boxes: 'very + somewhat satisfied'	**PUC Distribution**	**Ontario LDCs**
The availability of call-centre staff	70%	74%
The availability of system operators to respond to outages	74%	73%
The online self-serve options for managing your account	65%	73%
The online self-serve options for requesting service	57%	64%

Base: total respondents / An aggregate of respondents from 2021 participating LDCs

Based on customer responses, PUC Distribution has rated 77% for **Convenience of Services**.

Customer Experience Performance rating (CEPr)

Every touchpoint with customers on the phone, email, text, website, or in-person influences what customers think and feel about the organization. When an interaction with a customer meets their expectation, the opportunity to build loyalty (affinity) and support is strong. When the experience is a negative one, customers often conclude that the organization doesn't care.

A positive experience today sets up the perception that future interactions will also be excellent.

Customer Experience Performance rating (CEPr)

	PUC Distribution	National	Ontario
CEPr: all respondents	86%	84%	85%

Base: total respondents

The CEPr rating suggests that a very large majority of customers have a belief that they will have a good to excellent experience dealing with PUC Distribution professionals.

From an image point-of-view, PUC Distribution received very good scores for the attributes "keeps its promises to its customers and the community" and "overall the utility provides excellent quality services".

Customer Effort & Experience Score^{TM} (CEES)

Customers are time-pressed, and they want transactions related to getting questions answered or solving problems to be easy and fast. Customers dislike non-seamless handoffs when they have to deal with different people or departments to address their issues, and they dislike a slow response to their problem or concern. Customers also dislike “surprises,”; which is why they expect their utility to communicate with them pro-actively and, when needed, be ‘easy to do business with’.

The CEES as a metric is designed to help the organization remain focused on making things easy and fast for customers. The goal is to encourage improvements in all aspects of the customer’s journey from initial contact to completion of the issue. The central idea of CEES is about getting the most from your investments in people and technology.

PUC Distribution has rated a Customer Effort & Experience Score (CEES)^{TM} of 30%**.** The Ontario benchmark is 25%, and the UtilityPULSE database average is 34%.

Customer Effort & Experience Score (CEES)			
	Opportunity Range <15%	Good Range 15-35%	Very Good Range 35+%
PUC Distribution	--	30%	--
Ontario Benchmark	--	25%	--

Base: total respondents; range bands represent 2021 data and can change year-to-year

UtilityPULSE Report Card®

The purpose of the UtilityPULSE Report Card is to provide electric utilities with a snapshot of performance – on the criteria customers deem to be important.

PUC Distribution's UtilityPULSE Report Card®

Performance

	CATEGORY	PUC Distribution	National	Ontario
1	**Customer Care**	**B+**	**B+**	**B+**
	Price and Value	B	B+	B+
	Customer Service	A	B+	A
2	**Company Image**	**A**	**A**	**A**
	Company Leadership	A	A	A
	Corporate Stewardship	A	A	A
3	**Management Operations**	**A**	**A**	**A**
	Operational Effectiveness	A	A	A
	Power Quality and Reliability	A+	A	A
	OVERALL	**A**	**A**	**A**

Base: total respondents

Credibility & Trust Index

For most Ontario LDCs, over 40% of the customer base has been affected by the events of the past couple of years. As such, in a world with heightened unknowns, people will look for credible organizations that can be trusted. 84% of respondents agree strongly or somewhat that PUC Distribution is trusted and trustworthy. Your Credibility & Trust score is 84%, while the Ontario and National benchmarks sit at 84%.

Numbers at a Glance for 2021

	PUC Distribution	National	Ontario
Customer Satisfaction: Initial	91%	94%	93%
Customer Satisfaction: Post	88%	93%	92%
Would recommend	82%	83%	82%
Customer Experience Performance Rating (CEPr)	86%	84%	85%
Customer Centric Engagement Index (CCEI)	83%	83%	82%
Credibility & Trust Index	84%	84%	84%
UtilityPULSE Report Card©	A	A	A

As with the previous 23 years, the number one suggestion, by a wide margin, has been “better prices”. Price will always be top of mind for customers. For 2021, the second-highest suggestion was “better communications.” The third suggestion was “simplified billing.” Customers want increased ease, and we have seen that many want the ability to self-serve. These results make sense in light of an increasing push toward and need for digitization.

People want to be recognized as individuals AND get what they perceive to be good value. By allowing customers to choose whether they want to receive communication notices via email, text, or snail mail, etc., PUC Distribution is recognizing customers' personal preferences. The more specific you can be with your communications, the more likely you are to engage your customers and build an ongoing relationship with your brand.

We recommend that LDCs continue to work as fast as possible to digitize service. The goal is to provide options for customers to access help. As stated, customers who were previously resistant to doing things online are no longer resisting; they are adapting to using online methods with much more enthusiasm. This is the "new normal" and one that must be embraced and pro-actively addressed to meet the tastes and demands of customers better.

It is true the customer base still has lots of concerns and worries, such as getting ill or having a family member or friend get ill. Losing their job, or having a reduced pay cheque, or product shortages, etc. Fortunately, PUC Distribution is not at the top of the list of day-to-day concerns. 83% believe PUC Distribution 'efficiently manages the electricity system' - it continues to be a source of stability and reliability.

Your survey was conducted from August 30 - October 9, 2021, and is based on 401 one-on-one telephone interviews with residential and small commercial customers who pay or look after the electricity bill. In addition, survey findings for PUC Distribution are enhanced with the inclusion of data from our UtilityPULSE database and the independently produced Ontario and National Benchmarks.

The pandemic may not be fully over, but we are seeing some light. Your customers continue to be satisfied with the operations and image of PUC Distribution has done during this pandemic. One key for maintaining excellent scores resides in the next steps you take to ensure a continued positive customer experience in an increasingly digital world.

Simul/UtilityPULSE

Sid Ridgley

sridgley@simulcorp.com

David Malesich

david@utilitypulse.com

November 2021

UtilityPULSE, through polls and surveys, provides executives and managers with customer feedback that assists in making strategic and operational decisions. You know lots of companies that can gather data and then give a report. We believe that by specializing in the utility sector with our polls and surveys, you get a stronger analysis of data and answers to critical questions that help you formulate key strategies to assist your leaders in creating a better place to work and a better place to do business with.

UtilityPULSE is uniquely positioned to help your utility get feedback from Customers through its Annual Electric Utility Customer Satisfaction Survey or customized research designed for you. In addition, we understand what it takes to create an organization where employees are engaged and enthusiastic about customers and their work.

We're the only research company with 23 continuous years of producing an independent Ontario and National benchmark.

Anyone can collect and present data – we believe understanding the industry before doing so is crucial.

Contact us when experience, expertise, and high standards are essential for your next customer engagement activity. We promise to listen to your needs and design and delivery a customer engagement activity or survey which meets your needs.

Your personal contact is:

David Malesich

Phone: (647)274-9420 E-mail: david@utilitypulse.com

APPENDIX G

PUC Distribution Inc Audited Financial Statements 2021

Financial Statements of

PUC DISTRIBUTION INC.

And Independent Auditors' Report thereon

Year ended December 31, 2021

KPMG LLP
111 Elgin Street, Suite 200
Sault Ste. Marie ON P6A 6L6
Canada
Telephone (705) 949-5811
Fax (705) 949-0911

INDEPENDENT AUDITORS' REPORT

To the Shareholder of PUC Distribution Inc.

Opinion

We have audited the financial statements of PUC Distribution Inc. (the "Company"), which comprise:

- the statement of financial position as at December 31, 2021
- the statement of income and comprehensive income for the year then ended
- the statement of changes in shareholder's equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2021, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represents the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Sault Ste. Marie, Canada

April 7, 2022

PUC DISTRIBUTION INC.

Statement of Financial Position

December 31, 2021, with comparative information for 2020

	2021	2020
Assets		
Current assets:		
Cash	$ 815,229	$ 124,037
Accounts receivable (note 4)	6,121,404	5,738,294
Unbilled revenue	10,976,609	12,240,212
Payment in lieu of taxes recoverable	9,709	8,991
Inventory (note 5)	2,161,802	2,020,118
Prepaid expenses	200,875	67,672
Total current assets	20,285,628	20,199,324
Non-current assets:		
Property, plant and equipment (note 6)	112,462,126	105,376,966
Total assets	132,747,754	125,576,290
Regulatory balances (note 8)	9,437,146	4,570,573
Total assets and regulatory balances	$ 142,184,900	$ 130,146,863

See accompanying notes to financial statements.

PUC DISTRIBUTION INC.

Statement of Financial Position (continued)

December 31, 2021, with comparative information for 2020

	2021	2020
Liabilities and Shareholder's Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 12,141,711	$ 8,419,954
Customer deposits (note 11)	313,596	712,937
Dividends payable	610,080	610,080
Due to related parties (note 17)	12,638,877	10,688,540
Current portion of long-term debt (note 10)	1,923,586	1,727,219
Total current liabilities	27,627,850	22,158,730
Non-current liabilities:		
Deferred revenue (note 9)	7,034,528	4,829,126
Deferred tax liability	1,989,000	1,387,000
Long-term debt (note 10)	66,156,179	64,079,966
Total non-current liabilities	75,179,707	70,296,092
Total liabilities	102,807,557	92,454,822
Shareholder's equity:		
Share capital (note 12)	20,062,107	20,062,107
Retained earnings	18,618,415	16,811,240
Total shareholder's equity	38,680,522	36,873,347
Total liabilities and shareholder's equity	141,488,079	129,328,169
Regulatory balances (note 8)	696,821	818,694
Commitments and contingencies (note 16)		
Total liabilities, regulatory balances and shareholder's equity	$ 142,184,900	$ 130,146,863

See accompanying notes to financial statements.

Approved on behalf of the Board:

____________________ Director ____________________ Director

PUC DISTRIBUTION INC.

Statement of Income and Comprehensive Income

Year ended December 31, 2021, with comparative information for 2020

	2021	2020
Revenue:		
Electricity sales (note 13)	$ 71,763,066	$ 85,083,387
Distribution revenue (note 13)	19,207,805	19,032,237
	90,970,871	104,115,624
Other operating revenue (note 14)	7,281,109	7,630,820
	98,251,980	111,746,444
Expenses:		
Energy purchases	71,603,747	85,555,982
Operations and maintenance	6,406,837	6,434,364
General and administrative	4,025,734	3,129,473
Billing and collection	1,370,374	1,333,216
Depreciation and amortization	3,842,226	4,153,218
Community relations	5,206,928	5,307,274
	92,455,846	105,913,527
Income from operating activities	5,796,134	5,832,917
Net finance costs (note 15)	3,023,221	3,187,222
Income before tax and regulatory items	2,772,913	2,645,695
Income tax expense:		
Current (note 7)	71,089	76,523
Deferred (note 7)	602,000	677,000
	673,089	753,523
Income for the year before movements in regulatory deferral account balances	2,099,824	1,892,172
Net movement in regulatory deferral account balances related to income or loss	284,569	(188,490)
Income tax	(602,000)	(677,000)
	(317,431)	(865,490)
Net income, being total comprehensive income for the year	$ 2,417,255	$ 2,757,662

See accompanying notes to financial statements.

PUC DISTRIBUTION INC.

Statement of Changes in Shareholder's Equity

Year ended December 31, 2021, with comparative information for 2020

		Share Capital		Retained Earnings		Total
Balance as at January 1, 2020	$	20,062,107	$	14,663,658	$	34,725,765
Net income and comprehensive income		-		2,757,662		2,757,662
Dividends on common shares		-		(610,080)		(610,080)
Balance at December 31, 2020		20,062,107		16,811,240		36,873,347
Net income and comprehensive income		-		2,417,255		2,417,255
Dividends on common shares		-		(610,080)		(610,080)
Balance at December 31, 2021	$	20,062,107	$	18,618,415	$	38,680,522

See accompanying notes to financial statements.

PUC DISTRIBUTION INC.

Statement of Cash Flows

Year ended December 31, 2021, with comparative information for 2020

	2021	2020
Cash provided by (used in)		
Cash flows from operating activities:		
Total comprehensive income for the year	$ 2,417,255	$ 2,757,662
Items not involving cash:		
Depreciation and amortization	3,842,226	4,153,218
Amortization of deferred revenue	(140,229)	(123,988)
Net finance costs	3,023,221	3,187,222
Income tax expense	673,089	753,523
	9,815,562	10,727,637
Changes in non-cash working capital:		
Accounts receivable	(383,110)	(304,518)
Unbilled revenue	1,263,603	(141,968)
Inventory	(141,684)	(290,634)
Prepaid expenses	(133,203)	(2,455)
Accounts payable and accrued liabilities	3,721,757	(1,707,849)
Customer deposits	(399,341)	(354,615)
Income tax paid	(71,808)	(130,550)
Net movements in regulatory balances	(4,988,446)	(1,477,343)
Net cash from operating activities	8,683,330	6,317,705
Cash flows from financing activities:		
Repayment of long-term debt	(1,727,419)	(1,366,483)
Proceeds from issuance of long-term debt	4,000,000	5,800,000
Advances from related parties	1,950,337	1,647,268
Interest paid	(3,023,221)	(3,187,681)
Dividends paid	(610,080)	(900,000)
Net cash from financing activities	589,617	1,993,104
Cash flows from investing activities:		
Purchase of property, plant and equipment	(8,581,755)	(8,772,159)
Change in cash and cash equivalents	691,192	(461,350)
Cash and cash equivalents, beginning of year	124,037	585,387
Cash and cash equivalents, end of year	$ 815,229	$ 124,037

See accompanying notes to financial statements.

1. Reporting entity:

PUC Distribution Inc. (the “Company”) is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Company is located in the City of Sault Ste. Marie. The address of the Company’s registered office is 500 Second Line East, Sault Ste. Marie, Ontario Canada.

The Company delivers electricity and related energy services to residential and commercial customers in Sault Ste. Marie. The Company is wholly owned by PUC Inc., which is itself wholly owned by The Corporation of the City of Sault Ste. Marie.

2. Basis of presentation:

(a) Statement of compliance:

The Company's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

(b) Approval of the financial statements:

The financial statements were approved by the Board of Directors on April 7, 2022.

(c) Basis of measurement:

The financial statements have been prepared on the historical cost basis, unless otherwise stated.

(d) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest dollar.

(e) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected.

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in these financial statements is included in the following notes:

(i) Notes 3 (d), 6 - Property, plant and equipment: estimation of useful lives
(ii) Note 15 - Commitments and contingencies
(iii) Note 8 - recognition of regulatory balances
(iv) Note 3 (k) - leased assets

2. Basis of presentation (continued):

(f) Rate regulation:

The Company is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Company, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

(g) Rate setting:

i) Distribution revenue:

For the distribution revenue included in electricity sales, the Company files a "Cost of Service" ("COS") rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenses, debt and shareholder's equity required to support the Company's business. The Company estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers.

The Company filed a COS rate application in 2018 for rates effective October 1, 2018 to April 30, 2019 for which a Decision and Rate order was issued September 27, 2018.

The Company filed an IRM in 2018 requesting a 1.45% inflationary increase to distribution rates effective May 1, 2019 to be implemented July 1, 2019 for the period of May 1, 2019 to April 30, 2020. The IRM was approved on July 9, 2019.

2. Basis of presentation (continued):

(g) Rate setting (continued):

i. Distribution revenue (continued):

The Company filed an IRM and ICM in 2019 requesting a 1.55% inflationary increase to distribution rates and a substation upgrade rate rider effective May 1, 2020. The PUC elected to defer the implementation of rates to November 1, 2020 which the OEB approved October 8, 2020.

The Company filed an IRM in 2020 requesting a 1.90% inflationary increase to distribution rates effective May 1, 2021. The IRM was approved March 25, 2021.

ii. Electricity rates:

The OEB sets Ontario electricity prices for low-volume consumers twice each year (May and November) based on an estimate of how much it will cost to supply the province with electricity for the next year

All remaining consumers pay the market price for electricity.

The Corporation is billed for the cost of the electricity that its customers use by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

iii. TOU and tiered rate changes:

On December 15, 2020, the OEB announced new RPP TOU and tiered rates to reflect a decrease in the supply cost resulting from the Ontario Government's decision to remove certain renewable generation costs from the global adjustment and funding them through the tax base. The reduction began February 23, 2021 and was accompanied by a corresponding reduction to the Ontario Electricity Rebate.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments:

All financial assets and financial liabilities are measured at amortized cost. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(e). The Company does not enter into derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

Cash equivalents include short-term investments with maturities of three months or less when purchased.

3. Significant accounting policies (continued):

(b) Revenue recognition:

i) Electricity sales:

Electricity sales are recognized as the electricity is delivered to customers and includes the amounts billed to customers for electricity, including the cost of electricity supplied, distribution, and any other regulatory charges. Electricity revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Company has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

The difference between the amounts charged by the Company to customers, based on regulated rates, and the corresponding cost of electricity and related electricity service costs billed monthly by the Independent Electricity System Operator (“IESO”) is recorded as a settlement variance. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances, net of tax on the statement of income and comprehensive income.

ii) Capital contributions:

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 “Revenue from Contracts with Customers”. Cash contributions are initially recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Company's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the economic useful life of the constructed or contributed asset, which represents the period of ongoing service to the customer.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 Revenue from Contracts with Customers. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

iii) Rendering of services:

Revenue earned from the provision of services is recognized as the service is rendered.

3. Significant accounting policies (continued):

(b) Revenue recognition (continued):

iv) Conservation programs:

Incentive payments to which the Company is entitled from the IESO are recognized as revenue in the period when they are determined by the IESO and the amount is communicated to the Company.

c) Inventory:

Inventories consist of parts, supplies and materials held for the future capital expansion or replacement are valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and includes expenditures incurred in acquiring the material and supplies and other costs incurred in bringing them to their existing location and condition.

Net realizable value is the estimated selling price in the ordinary course of business, less estimated selling expenses.

(d) Property, plant and equipment:

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour, and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Company's borrowings. Qualifying assets are considered to be those that take a substantial period of time to construct.

When parts of an item of property, plant and equipment ("PP&E") have different useful lives, they are accounted for as separate items (major components) of PP&E.

Gains and losses on the disposal of an item of PP&E are determined by comparing the proceeds from disposal, if any, with the carrying amount of the item of PP&E and are recognized net within other income in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Company and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

Depreciation is calculated over the depreciable amount and is recognized in income on a straight-line basis over the estimated useful life of each part or component of an item of PP&E. The depreciable amount is cost. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and in service.

3. Significant accounting policies (continued):

(d) Property, plant and equipment (continued):

The estimated useful lives are as follows:

Buildings	25 – 50 years
Transmission and distribution	15 – 60 years
Plant and equipment	5 – 40 years

Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate.

(e) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its current carrying amount (using prevailing interest rates), and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount.

All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than inventories and deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit"). The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

3. Significant accounting policies (continued):

(e) Impairment (continued):

(ii) Non-financial assets (continued):

An impairment loss is recognized if the carrying amount of an asset or its cash-generating unit exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation, if no impairment loss had been recognized.

(f) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(g) Regulation:

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unrelated environment and regulated entities that have not adopted IFRS 14, Regulatory Deferral Accounts.

(h) Regulatory deferral accounts:

The Company has determined that certain asset and liability balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the Accounting Procedures Handbook for Electricity Distributors. Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding the Company's regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory asset and liability balances on the Company's statement of financial position, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB.

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. These amounts have been accumulated and deferred in anticipation of their future recovery in electricity distribution rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Company.

3. Significant accounting policies (continued):

(h) Regulatory deferral accounts (continued):

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in profit and loss. The debit balance is reduced by the amount of customer billings as electricity is delivered to the customer and the customer is billed at rates approved by the OEB for the recovery of the capitalized costs.

Regulatory deferral account credit balances are recognized if it is probable that future billings in an amount at least equal to the credit balance will be reduced as a result of rate-making activities. The offsetting amount is recognized in profit and loss. The credit balance is reduced by the amounts returned to customers as electricity is delivered to the customer at rates approved by the OEB for the return of the regulatory account credit balance.

The probability of recovery or repayment of the regulatory account balances are assessed annually based upon the likelihood that the OEB will approve the change in rates to recover or repay the balance. Any resulting impairment loss is recognized in profit and loss in the year incurred.

Regulatory deferral accounts attract interest at OEB prescribed rates. In 2021 the rate was 0.57% for the year. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable.

In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, the balances are recorded in the Company's statement of income and comprehensive income in the period when the assessment is made. Regulatory balances that do not meet the definition of an asset or liability under any other IFRS are segregated on the statement of financial position and on the statement of income and comprehensive income as net movements in regulatory balances, net of tax. The netting of regulatory debit and credit balances is not permitted.

The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

(i) Credit support for service delivery:

Credit support for service delivery represents cash deposits from electricity distribution customers as well as construction deposits.

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Customer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Company.

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. Cash contributions are initially recorded as credit support for service delivery, a current liability. Once the distribution system asset is completed or modified as outlined in the terms of the contract, the contribution amount is transferred to deferred revenue.

3. Significant accounting policies (continued):

(j) Deferred revenue and assets transferred from customers:

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as deferred revenue within non-current liabilities. Deferred revenue represents the Company's obligation to continue to provide customers access to the supply of electricity, and is amortized to income on a straight-line basis over the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

(k) Leased assets:

At inception of a contract, the Company assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether:

(i) The contract involves the use of an identified asset;
(ii) The Company has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use; and
(iii) The Company has the right to direct the use of the asset. The Company has this right when it has the decision-making rights that are most relevant to changing how and for what purpose the asset is used is predetermined, the Company has the right to direct the use of the asset if either:

a) The Company has the right to operate the asset; or
b) The Company designed the asset in a way that predetermines how and for what purposes it will be used.

Short-term leases and low value assets

The Company has elected not to recognize right-of-use assets and lease liabilities for short-term leases that have a lease term of 12 months or less and leases of low-value assets. The Company recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

3. Significant accounting policies (continued):

(l) Payment in lieu of taxes:

The Company is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations' Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Company ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Company's Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Company was not subject to income or capital taxes.

PILs comprises current and deferred payments in lieu of income tax. PILs recognized in income and loss except to the extent that it relates to items recognized directly in either comprehensive income or equity, in which case, it is recognized in comprehensive income or in equity.

Current PILS is the expected amount of tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred PILs comprise the net tax effects of temporary differences between the tax basis of assets and liabilities and their respective carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

Deferred PILs assets and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred PILs assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

A deferred PILs asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred PILs assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

3. Significant accounting policies (continued):

(m) Critical accounting estimates and judgments:

The Company makes estimates and assumptions about the future that affect the reported amounts of assets and liabilities. Estimates and judgments are continually evaluated based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. In the future, actual experience may differ from these estimates and assumptions.

The effect of a change in an accounting estimate is recognized prospectively by including it in comprehensive income in the period of the change, if the change affects that period only; or in the period of the change and future periods, if the change affects both.

The estimates and assumptions that have a significant risk of causing material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Fair value of financial instruments:

The Company determines the fair value of financial instruments that are not quoted in an active market, using valuation techniques. Those techniques are significantly affected by the assumptions used, including discount rates and estimates of future cash flows. In that regard, the derived fair value estimates cannot always be substantiated by comparison with independent markets and, in many cases, may not be capable of being realized immediately.

The methods, and assumptions applied, and the valuation techniques used, for financial instruments that are not quoted in an active market are disclosed in note 16.

Payment in lieu of taxes:

The Company periodically assesses its liabilities and contingencies related to PILs for all years open to audit based on the latest information available. For matters where it is probable that an adjustment will be made, the Company records its best estimate of the tax liability including the related interest and penalties in the current PILs provision. Management believes they have adequately provided for the probable outcome of these matters; however, the final outcome may result in a materially different outcome that the amount included in the PILs liabilities.

Useful lives of depreciable assets:

Management reviews the useful lives of depreciable assets at each reporting date. At December 31, 2021, management assesses that the useful lives represent the expected utility of the assets to the Company. The carrying amounts are analyzed in note 6. Actual results, however, may vary due to technical obsolescence, particularly for software and electronic equipment.

3. Significant accounting policies (continued):

(m) Critical accounting estimates and judgments (continued):

Impairment:

An impairment loss is recognized for the amount by which an asset's carrying amount exceeds its recoverable amount, which is the higher of fair value less cost to sell and value-in-use. To determine the value-in-use, management estimates expected future cash flows from each asset or cash generating unit and determines a suitable interest rate in order to calculate the present value of those cash flows. In most cases, determining the applicable discount rate involves estimating the appropriate adjustment to market risk and the appropriate adjustment to asset-specific risk factors. In the process of measuring expected future cash flows management makes assumptions about future operating results. These assumptions relate to future events and circumstances.

(n) Changes in accounting policy:

The international Accounting Standards Board (IASB) has issued Standards, Interpretations and Amendments to Standards that were adopted by the Company effective January 1, 2021, including Interest Rate Benchmark Reform – Phase 2 (Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16). The amendment did not have an impact on the financial statements.

(o) Standards issued but not yet adopted:

The Company is evaluating the adoption of the following new and revised standards along with any subsequent amendments.

- Property, Plant and Equipment – Proceeds before Intended Use (Amendments to IAS 16) – effective date January 1, 2022
- Annual Improvements to IFRS Standards 2018-2020 – effective date January 1, 2022
- Reference to the Conceptual Framework (Amendments to IFRS 3) – effective date January 1, 2022
- Onerous Contracts – Cost of Fulfilling a Contract (Amendments to IAS 37) – effective date January 1, 2022
- Definition of Accounting Estimates (Amendments to IAS 8) – effective date January 1, 2023
- Deferred Tax related to Assets and Liabilities arising from a Single Transaction (Amendments to IAS 12 Income Taxes) – effective date January 1, 2023
- Disclosure initiative – Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2) – effective date January 1, 2023
- Classification of Liabilities as Current or Non-current (Amendments to IAS 1) – effective date January 1, 2024

None of these standards or amendments to existing standards have been early adopted. The Company has not determined if there will be any impact on the financial statements related to the adoption of these new standards.

4. Accounts receivable:

	2021	2020
Trade receivables	$ 5,718,432	$ 5,392,292
Other receivables	402,972	346,002
	$ 6,121,404	$ 5,738,294

Included in the receivables balance is an estimated credit loss in the amount of $350,000 (2020 - $350,000)

5. Inventory:

The amount of inventories consumed by the Company and recognized as an expense during 2021 was $238,818 (2020 - $272,313).

	2021	2020
Stores	$ 1,107,180	$ 1,003,436
Wire and cable	678,789	695,548
Poles	375,833	321,134
	$ 2,161,802	$ 2,020,118

6. Property, plant and equipment:

(a) Cost or deemed cost:

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2021	$ 26,215,729	$ 78,586,665	$21,813,511	$4,820,290	$131,436,195
Additions	742,167	4,411,301	646,161	7,477,832	13,277,461
Disposals/retirements	–	–	–	(2,350,075)	(2,350,075)
Balance at December 31, 2021	$ 26,957,896	$ 82,997,966	$22,459,672	$9,948,047	$142,363,581

	Land And buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2020	$ 26,075,741	$ 73,567,004	$21,087,433	$1,275,692	$122,005,870
Additions	139,988	5,019,661	726,078	3,544,598	9,430,325
Balance at December 31, 2020	$ 26,215,729	$ 78,586,665	$21,813,511	$4,820,290	$131,436,195

6. Property, plant and equipment (continued):

(b) Accumulated depreciation:

		Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2021	$	4,780,047	$14,801,570	$ 6,477,612	$ –	$ 26,059,229
Depreciation charge		706,421	2,584,825	550,980	–	3,842,226
Balance at December 31, 2021	$	5,486,468	$17,386,395	7,028,592	$ –	$ 29,901,455

		Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 31, 2020	$	4,087,214	$12,335,673	$ 5,483,125	$ –	$ 21,906,012
Depreciation charge		692,833	2,465,897	994,487	–	4,153,217
Balance at December 31, 2020	$	4,780,047	$14,801,570	$ 6,477,612	$ –	$ 26,059,229

Contributed tangible assets:

Contributed tangible assets have been recognized at a fair market value at the date of contribution. The carrying value of contributed assets at the end of the year is $7,034,528 (2020 - $4,829,126), comprised of distribution infrastructure (note 9).

(c) Carrying amounts:

		Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
At December 31, 2021	$	21,471,428	65,611,571	15,431,080	9,948,047	112,462,126
At December 31, 2020	$	21,435,682	63,785,095	15,335,899	4,820,290	105,376,966

(d) Security:

At December 31, 2021, property, plant and equipment with a carrying amount of $112,462,126 (2020 - $105,376,966) are subject to a general security agreement. See note 10 for additional information.

7. Payments in lieu of income taxes:

Payment in lieu of taxes expense (recovery):

Current PILs Expense:

	2021	2020
Current payments in lieu of income tax	$ 71,089	$ 76,523
Payment in lieu of income tax expense	$ 71,089	$ 76,523

Deferred PILs Expense:

	2021	2020
Origination and reversal of timing differences	$ 602,000	$ 677,000
Total payment in lieu of income tax expense	$ 673,089	$ 753,523

Reconciliation of effective tax rate:

	2021	2020
Net income being total comprehensive income for the year	$ 2,536,549	$ 2,834,185
Statutory rate	26.5%	26.5%
Income tax	672,185	751,059
Increase (decrease) resulting from:		
Permanent difference	430	1,563
Other	474	901
	$ 673,089	$ 753,523

Significant components of the Company's deferred tax balances are as follows:

	2021	2020
Deferred tax assets (liabilities):		
Plant and equipment	$ (3,152,000)	$ (2,424,000)
Reserves	92,000	92,000
CMT credit	437,000	366,000
Non-capital loss carry forward	627,000	579,000
Donations	7,000	–
	$ (1,989,000)	$ (1,387,000)

8. Regulatory deferral account balance:

The following is a reconciliation of the carrying amount for each class of regulatory deferral account balances:

	January 1, 2021	Balances arising in the period	Recovery/ reversal	December 31, 2021	Remaining recovery/ reversal period (years)
Regulatory deferral account debit balances					
Settlement Variance	$ 2,629,422	$ (24,790)	$4,330,252	$6,934,884	< 2
Deferred taxes	1,886,000	–	602,000	2,488,000	
LRAMVA	55,151	237	(41,126)	14,262	< 1
Total amount related to regulatory deferral account debit balances	$ 4,570,573	$ (24,553)	$ 4,891,126	$9,437,146	
Regulatory deferral account credit balances					
Deferred Taxes	$ (499,000)	$ –	$ –	$ (499,000)	
Smart Meter Entity Charges	(24,157)	(469)	7,918	(16,708)	< 1
Regulatory Asset Recovery Account Phase 10	(11,432)	9,658	–	(1,774)	< 1
Regulatory Asset Recovery Account Phase 11	–	5,040	226,595	231,635	< 1
Accelerated CCA	(284,105)	(1,619)	(125,250)	(410,974)	< 2
Total amount related to regulatory deferral account credit balances	$ (818,694)	$ 12,610	$ 109,263	$ (696,821)	

	January 1, 2020	Balances arising in the period	Recovery/ reversal	December 31, 2020	Remaining recovery/ reversal period (years)
Regulatory deferral account debit balances					
Settlement Variance	$ 2,439,984	$ (56,265)	$ 245,703	$2,629,422	<1
Deferred taxes	966,000	–	920,000	1,886,000	
LRAMVA	307,609	1,439	(253,897)	55,151	<1
Total amount related to regulatory deferral account debit balances	$ 3,713,593	$ (54,826)	$ 911,806	$4,570,573	
Regulatory deferral account credit balances					
Deferred Taxes	$ (256,000)	$ -	$(243,000)	$ (499,000)	
Stranded Meters	(34)	34	–	–	
Smart Meter Entity Charges	(23,822)	(276)	(59)	(24,157)	<1
Regulatory Asset Recovery Account Phase 5-9	(567,447)	(32,584)	600,031	–	
Regulatory Asset Recovery Account Phase 10	(591,756)	175,023	405,301	(11,432)	<1
CGAAP Accounting Changes	2	(284,107)	–	(284,105)	
Total amount related to regulatory deferral account credit balances	$ $ (1,439,057)	$ (141,910)	$ 762,273	$ (818,694)	

8. Regulatory deferral account balance (continued):

The regulatory deferral account balances are recovered or settled through rates set by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Company has received approval from the OEB to establish its regulatory deferral account balances.

Group 1 deferral and variance accounts (Group 1 accounts) track the differences between the costs that a distributor is billed for certain IESO and host distributor services (including the cost of power) and the associated revenues that the distributor receives from its customers for these services. The total net difference between these costs and revenues is disposed to customers through a temporary charge or credit known as a rate rider.

The OEB requires the Company to estimate its income taxes when it files a COS application to set its rates. As a result, the Company has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Company's deferred tax balance fluctuates.

9. Deferred revenue:

Deferred revenue relates to capital contributions received from customers and others for distribution assets.

	2021	2020
Cost or deemed cost		
Balance at January 1,	$ 5,288,573	$ 4,630,407
Contributions received during the year	2,345,631	658,166
Balance at December 31	$ 7,634,204	$ 5,288,573

	2021	2020
Accumulated amortization		
Balance at January 1,	$ 459,447	$ 335,459
Amounts amortized during the year	140,229	123,988
Balance at December 31	$ 599,676	$ 459,447

Carrying amounts at December 31,	$ 7,034,528	$ 4,829,126

Contributions received include $1,759,824 (2020 – $Nil) related to construction in process projects.

10. Long-term debt:

		2021	2020
Notes payable:			
i.	Ontario Infrastructure smart meter loan	$ 2,686,370	$ 3,015,290
ii.	Ontario Infrastructure building loan	16,687,088	17,331,453
iii.	Ontario Infrastructure term loan 1	12,676,549	13,126,402
iv.	Ontario Infrastructure term loan 2	5,495,718	5,800,000
v.	Ontario Infrastructure construction loan	4,000,000	–
vi.	Note payable to parent company, PUC Inc.	26,534,040	26,534,040
		68,079,765	65,807,185
Current portion of long-term debt		(1,923,586)	(1,727,219)
		$ 66,156,179	$64,079,966

i) Smart Meter Loan with Ontario Infrastructure and Lands Corporation (OILC): Reducing Debenture Facility, amortization period of 15 years to July 17, 2028 with loan interest rate of 3.82%. Interest of $106,837 (2020 - $119,245) was paid and expensed during the year. The loan is payable in the amount of $220,496 in semi-annual principal and interest repayments. Security is in the form of a second ranking general security agreement.

ii) Land and Building Loan with OILC: Reducing Debenture Facility, amortization period of 25 years to October 1, 2038, with loan interest rate of 4.57%. Interest of $778,457 (2020 - $807,576) was paid and expensed during the year. The loan is payable in the amount of $118,568 monthly which includes principal and interest. Security is in the form of a first charge over the Company's land and building and a third ranking general security agreement.

iii) Ontario Infrastructure term loan 1, for electric distribution infrastructure, with interest rate of 3.47%, repayable over 25 years by a blended principal and interest payment of $74,852 monthly maturing on May 16, 2041. Interest of $448,376 (2020 - $463,697) was paid and expensed during the year. Security is in the form of a fourth ranking general security agreement and a guarantee and assignment of shares from the company’s shareholder, PUC Inc.

10. Long-term debt (continued):

iv) Ontario Infrastructure term loan 2, for electric distribution infrastructure, with interest rate of 2.11%, repayable over 15 years by a blended principal and interest payment of $37,618 monthly maturing on January 15, 2036. Interest of $123,055 (2020 - $33,436) was paid and expensed during the year. Security is in the form of a fifth ranking general security agreement and a guarantee and assignment of shares from the company's shareholder, PUC Inc.

v) Ontario Infrastructure revolving loan, to a maximum of $30,000,000 available until September 30, 2024. Draws on the revolving loan are repayable in interest only payments at floating interest rates. Interest of $26,395 (2020 – $Nil) was paid and expensed during the year. The construction loan was converted to long-term debt on March 1, 2022, at an interest rate of 3.65%, repayable in blended monthly principal and interest payments of $23,508, maturing March 1, 2042. As of December 31, 2021, $20,200,000 remains available under the facility after the draw of the construction loan of $4,000,000 and the term loan 2 of $5,800,000 in 2020. Security is in the form of a second ranking general security agreement.

vi) Note payable to parent company, PUC Inc., bears interest payable quarterly at rates periodically negotiated and principal payable one year after demand. The average interest rate for 2021 was 6.1% (2020 – 6.1%). The balance outstanding for 2021 is $26,534,040 (2020 - $26,534,040).

Borrowing costs include interest which is capitalized related to eligible qualifying assets. During the year interest of $221,307 (2020 - $95,646) was capitalized.

Principal payments on the long-term debt are as follows:

2022	$ 1,923,586
2023	2,030,770
2024	2,107,035
2025	2,186,316
2026	2,269,079
2027 - 2042	57,562,979
	$ 68,079,765

Reconciliation of movements of liabilities to cash flows arising from financing activities:

	2021	2020
Long-term debt, beginning of year	$ 65,807,185	$ 61,373,668
Less: cash outflows for principal repayments	(1,727,420)	(1,366,483)
Add: cash inflow for new debt	4,000,000	5,800,000
Long-term debt, end of year	$ 68,079,765	$ 65,807,185

11. Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers, as well as construction deposits.

Deposits from electricity distribution customers are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service. The balance at December 31, 2021 is $313,596 (2020 - $712,937).

12. Share capital:

	2021	2020
Authorized:		
Unlimited number of special shares, non-voting, non-cumulative		
Redeemable at $10,000 per share		
10,000 Common shares		
Issued and outstanding:		
8,612 common shares	$ 20,062,107	$ 20,062,107

13. Electricity sales:

The Corporation generates revenue primarily from the sale and distribution of electricity to its customers. In the following table, revenue from contracts with customers is disaggregated by type

	2021	2020
Residential	$ 47,643,571	$ 54,222,874
Commercial	42,752,718	49,263,706
Street lights	574,582	629,044
	$ 90,970,871	$ 104,115,624

14. Other operating revenue:

Other income comprises:

	2021	2020
Conservation and demand management	$ 4,343,196	$ 4,731,173
Service work related to distribution operations	1,495,687	1,501,205
Pole attachment and duct rentals	863,954	828,248
Account-related charges	292,124	296,114
Other	145,919	150,092
Capital contributions from customers amortized to revenue	140,229	123,988
Total other income	$ 7,281,109	$ 7,630,820

15. Finance income and expense:

	2021	2020
Interest income	$ 4,281	$ 459
Interest expense on long-term debt	2,880,389	2,946,885
Other interest and carrying charges	147,113	240,796
	3,027,502	3,187,681
Net finance costs recognized in profit or loss	$ 3,023,221	$ 3,187,222

16. Commitments and contingencies:

i) General:

From time to time, the Company is involved in various litigation matters arising in the ordinary course of its business. The Company has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Company's financial position, results of operations or its ability to carry on any of its business activities.

ii) General Liability Insurance:

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2021, no assessments have been made.

iii) Letter of Guarantee:

The Company maintains a $5,000,000 letter of guarantee with its Bank in favor of the IESO.

17. Related party transactions:

(a) Parent, ultimate controlling party, and other related parties:

The sole shareholder of the Company is PUC Inc., which in turn is wholly-owned by the Corporation of the City of Sault Ste. Marie (City). The City produces financial statements available for public use. Other related parties to the Company include:

- PUC Services Inc. (Services) - 100% owned by City
- Public Utilities Commission of the City of Sault Ste. Marie (Utility) - 100% owned by the City.
- Northern Waterworks Inc. (NWI) - 100% owned by PUC Inc.
- 17 Trees Inc. (17 Trees) – 33.3% owned by PUC Inc, managed by PUC Services Inc.
- Watertight Lining Solutions Inc.(WLS) – 100% owned by PUC Inc.
- PUC (Transmission) LP Inc. (LP Inc.) – 100% owned by PUC Inc.
- PUC (Transmission) GP Inc. (GP Inc.) – 100% owned by PUC Inc.

17. Related party transactions (continued):

(b) Key management personnel:

The key management personnel of the Company have been defined as members of its board of directors and is summarized below:

	2021	2020
Directors' fees	$ 22,283	$ 12,035

(c) Transactions with ultimate parent (the City):

In the year, the Company had significant transactions with the City, its ultimate parent and a government entity, with the delivery of electricity throughout the year to meet the electricity needs of the City and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB. The amount charged to the City for electricity consumed by streetlights is $614,160 (2020 - $631,183) and for other electricity consumption is $3,562,342 (2020 - $3,915,844).

(d) Transaction with PUC Inc.:

The Company declared dividends on its common shares held by PUC Inc. in the amount of $610,080 (2020 - $610,080). This amounts to $70.84 per share (2020 - $70.84 per share). Dividends payable to PUC Inc. at the end of the year amount to $610,080 (2020 - $610,080).

(e) Transactions with Services:

The Company has a management, operation and maintenance agreement with Services which has been extended to November 30, 2022, under which Services (owned 100% by the City) manages, controls, administers and operates the business of the Company. During the year, management fees were charged by Services in the amount of $4,913,266 (2020 - $5,318,112).

The Company pays interest on its payable balance to Services at the OEB prescribed short-term borrowing rate on its average monthly balance. Interest of $180,408 (2020 – $155,336) was paid during the year.

The payable balance to Services at December 31, 2021 amounts to $12,638,877 (2020 - $10,688,540).

(f) Transactions with 17 Trees:

The Company is related to 17 Trees which is owned 33% by PUC Inc. During the year tree trimming services were charged by 17 Trees in the amount of $898,707 (2020 - $604,360) related to tree trimming services. Amounts payable to 17 Trees at the end of the year amount to $171,393 (2020 - $28,595).

(g) Transactions with other related entities:

The Company is related to WLS, LP Inc., and GP Inc. which are owned 100% by PUC Inc. There were no related party transactions from these entities with the Company during the year (2020 - $NIL).

These transactions are in the normal course of operations and are measured at the exchange amount which is the amount of consideration agreed to by the related parties.

18. Financial instruments and risk management:

(a) Fair value disclosure:

Cash and cash equivalents are measured at fair value. The carrying values of receivables, and accounts payable and accrued charges approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

(b) Financial risks:

The Company understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Company's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

i) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Company, such as accounts receivable, expose it to credit risk. The Company earns its revenue from a broad base of customers located in the City. No single customer accounts for a balance in excess of 2.63% of total accounts receivable.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in net income. Subsequent recoveries of receivables previously provisioned are credited to net income. The balance of the allowance for impairment at December 31, 2021 is $350,000 (2020 - $350,000).

The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. The Company has over 33 thousand customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2021, the Company holds security deposits in the amount of $313,596 (2020 - $712,937).

The Corporation has estimated the expected credit losses using its historical loss rates and recent trends for customer collections along with current and forecasted economic conditions and data. To support residential and small business customers struggling to pay their energy bills, the Government of Ontario provided funding for the COVID-19 Energy Assistance Program ("CEAP"). The Corporation was allocated a portion of this funding and actively participated in the program.

18. Financial instruments and risk management (continued):

(b) Financial risks (continued):

ii) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Company currently does not have any material commodity or foreign exchange risk. The Company is exposed to fluctuations in interest rates as the regulated rate of return for the Company's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

iii) Liquidity risk:

The Company monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Company has access to a $4,500,000 credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they come due. As at December 31, 2021, no amounts had been drawn under the Company's credit facilities.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

iv) Capital disclosures:

The main objectives of the Company, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2021, shareholder's equity amounts to $38,680,522 (2020 - $36,873,347) and long-term debt amounts to $68,079,765 (2020 - $65,807,185).

APPENDIX H

PUC Distribution Inc Audited Financial Statements 2020

Financial Statements of

PUC DISTRIBUTION INC.

And Independent Auditors' Report thereon

Year ended December 31, 2020

KPMG LLP
111 Elgin Street, Suite 200
Sault Ste. Marie ON P6A 6L6
Canada
Telephone (705) 949-5811
Fax (705) 949-0911

INDEPENDENT AUDITORS' REPORT

To the Shareholder of PUC Distribution Inc.

Opinion

We have audited the financial statements of PUC Distribution Inc. (the "Company"), which comprise:

- the statement of financial position as at December 31, 2020
- the statement of income and comprehensive income for the year then ended
- the statement of changes in shareholder's equity for the year then ended
- the statement of cash flows for the year then ended
- and notes to the financial statements, including a summary of significant accounting policies

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2020, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "Auditors' Responsibilities for the Audit of the Financial Statements" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditors' Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represents the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants, Licensed Public Accountants

Sault Ste. Marie, Canada

April 6, 2021

PUC DISTRIBUTION INC.

Statement of Financial Position

December 31, 2020, with comparative information for 2019

		2020		2019
Assets				
Current assets:				
Cash and cash equivalents	$	124,037	$	585,387
Accounts receivable (note 4)		5,738,294		5,433,776
Unbilled revenue		12,240,212		12,098,244
Payment in lieu of taxes recoverable		8,991		-
Inventory (note 5)		2,020,118		1,729,484
Prepaid expenses		67,672		65,217
Total current assets		20,199,324		19,912,108
Non-current assets:				
Property, plant and equipment (note 6)		105,376,966		100,099,858
Total assets		125,576,290		120,011,966
Regulatory balances (note 8)		4,570,573		3,713,593
Total assets and regulatory balances	$	130,146,863	$	123,725,559

See accompanying notes to financial statements.

PUC DISTRIBUTION INC.

Statement of Financial Position (continued)

December 31, 2020, with comparative information for 2019

Liabilities and Shareholder's Equity

	2020	2019
Current liabilities:		
Accounts payable and accrued liabilities	$ 8,419,954	$ 10,127,802
Customer deposits (note 11)	712,937	1,067,552
Payment in lieu of taxes	-	45,036
Dividends payable	610,080	900,000
Due to related parties	10,688,540	9,041,731
Current portion of long-term debt (note 10)	1,727,219	1,366,680
Total current liabilities	22,158,730	22,548,801
Non-current liabilities:		
Deferred revenue (note 9)	4,829,126	4,294,948
Deferred tax liability	1,387,000	710,000
Long-term debt (note 10)	64,079,966	60,006,988
Total non-current liabilities	70,296,092	65,011,936
Total liabilities	92,454,822	87,560,737
Shareholder's equity:		
Share capital (note 12)	20,062,107	20,062,107
Retained earnings	16,811,240	14,663,658
Total shareholder's equity	36,873,347	34,725,765
Total liabilities and shareholder's equity	129,328,169	122,286,502
Regulatory balances (note 8)	818,694	1,439,057
Commitments and contingencies (note 16)		
Total liabilities, regulatory balances and shareholder's equity	$ 130,146,863	$ 123,725,559

See accompanying notes to financial statements.

Approved on behalf of the Board:

____________________ Director

____________________ Director

PUC DISTRIBUTION INC.

Statement of Income and Comprehensive Income

Year ended December 31, 2020, with comparative information for 2019

	2020	2019
Revenue:		
Electricity sales (note 13)	$ 85,083,387	$ 74,373,612
Distribution revenue (note 13)	19,032,237	19,071,168
Cost of electricity sold	(85,555,982)	(76,035,021)
	18,559,642	17,409,759
Other operating revenue (note 14)	7,630,820	6,747,157
Net operating revenue	26,190,462	24,156,916
Expenses:		
Operations and maintenance	6,434,364	6,302,246
General and administrative	3,129,473	3,172,654
Billing and collection	1,333,216	1,354,435
Depreciation and amortization	4,153,218	4,010,672
Community relations	5,307,274	4,680,636
	20,357,545	19,520,643
Income from operating activities	5,832,917	4,636,273
Net finance costs (note 15)	3,187,222	3,130,511
Income before tax and regulatory items	2,645,695	1,505,762
Income tax expense (recovery):		
Current (note 7)	76,523	126,958
Deferred (note 7)	677,000	638,000
	753,523	764,958
Income for the year before movements in regulatory deferral account balances	1,892,172	740,804
Net movement in regulatory deferral account balances related to income or loss	(188,490)	(1,661,409)
Income tax	(677,000)	(638,000)
	(865,490)	(2,299,409)
Net income, being total comprehensive income for the year	$ 2,757,662	$ 3,040,213

See accompanying notes to financial statements.

PUC DISTRIBUTION INC.

Statement of Changes in Shareholder's Equity

Year ended December 31, 2020, with comparative information for 2019

	Share Capital	Retained Earnings	Total
Balance as at January 1, 2019	$ 20,062,107	$ 12,523,445	$ 32,585,552
Net income and comprehensive income	-	3,040,213	3,040,213
Dividends on common shares	-	(900,000)	(900,000)
Balance at December 31, 2019	20,062,107	14,663,658	34,725,765
Net income and comprehensive income	-	2,757,662	2,757,662
Dividends on common shares	-	(610,080)	(610,080)
Balance at December 31, 2020	$ 20,062,107	$ 16,811,240	$ 36,873,347

See accompanying notes to financial statements.

PUC DISTRIBUTION INC.

Statement of Cash Flows

Year ended December 31, 2020, with comparative information for 2019

		2020		2019
Cash provided by (used in)				
Cash flows from operating activities:				
Total comprehensive income for the year	$	2,757,662	$	3,040,213
Items not involving cash:				
Depreciation and amortization		4,153,218		4,010,672
Amortization of deferred revenue		(123,988)		(101,862)
Net finance costs		3,187,222		3,130,511
Income tax expense		753,523		764,958
		10,727,637		10,844,492
Changes in non-cash working capital:				
Accounts receivable		(304,518)		(12,646)
Unbilled revenue		(141,968)		(3,540,640)
Inventory		(290,634)		(119,056)
Prepaid expenses		(2,455)		380,463
Due to related parties		1,647,268		5,763,202
Accounts payable and accrued liabilities		(1,707,849)		1,976,290
Customer deposits		(354,615)		(31,781)
Income tax paid		(130,550)		(41,144)
Net movements in regulatory balances		(1,477,343)		(5,035,197)
Net cash from operating activities		7,964,973		10,183,983
Cash flows from financing activities:				
Repayment of long-term debt		(1,366,483)		(1,312,679)
Proceeds of issuance of long-term debt		5,800,000		-
Interest paid		(3,187,681)		(3,133,430)
Dividends paid		(900,000)		-
Net cash from financing activities		345,836		(4,446,109)
Cash flows from investing activities:				
Purchase of property, plant and equipment		(8,772,159)		(5,767,100)
Change in cash and cash equivalents		(461,350)		(29,226)
Cash and cash equivalents, beginning of year		585,387		614,613
Cash and cash equivalents, end of year	$	124,037	$	585,387

See accompanying notes to financial statements.

1. Reporting entity:

PUC Distribution Inc. (the "Company") is a rate regulated, municipally owned hydro distribution company incorporated under the laws of Ontario, Canada. The Company is located in the City of Sault Ste. Marie. The address of the Company's registered office is 500 Second Line East, Sault Ste. Marie, Ontario Canada.

The Company delivers electricity and related energy services to residential and commercial customers in Sault Ste. Marie. The Company is wholly owned by PUC Inc., which is itself wholly owned by The Corporation of the City of Sault Ste. Marie.

2. Basis of presentation:

(a) Statement of compliance:

The Company's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

(b) Approval of the financial statements:

The financial statements were approved by the Board of Directors on April 6, 2021.

(c) Basis of measurement:

The financial statements have been prepared on the historical cost basis, unless otherwise stated.

(d) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest dollar.

(e) Use of estimates and judgments:

The preparation of financial statements in conformity with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and the reported amounts of assets, liabilities, income and expenses and disclosure of contingent assets and liabilities. Actual results may differ from those estimates.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future periods affected.

Information about critical judgments in applying accounting policies that have the most significant effect on the amounts recognized in these financial statements is included in the following notes:

(i) Notes 3 (d), 6 - Property, plant and equipment: estimation of useful lives
(ii) Note 15 - Commitments and contingencies
(iii) Note 8 - recognition of regulatory balances
(iv) Note 3 (k) - leased assets

2. Basis of presentation (continued):

(f) Rate regulation:

The Company is regulated by the Ontario Energy Board ("OEB"), under the authority granted by the *Ontario Energy Board Act, 1998*. Among other things, the OEB has the power and responsibility to approve or set rates for the transmission and distribution of electricity, providing continued rate protection for electricity consumers in Ontario, and ensuring that transmission and distribution companies fulfill obligations to connect and service customers. The OEB may also prescribe license requirements and conditions of service to local distribution companies ("LDCs"), such as the Company, which may include, among other things, record keeping, regulatory accounting principles, separation of accounts for distinct businesses, and filing and process requirements for rate setting purposes.

The OEB has a decision and order in place banning utilities in Ontario from disconnecting homes for non-payment during the winter. This ban is normally in place from November 15 to April 30 each year but was extended this year to July 31, 2020.

(g) Rate setting:

i) Distribution revenue:

For the distribution revenue included in electricity sales, the Company files a "Cost of Service" ("COS") rate application with the OEB every five years where rates are determined through a review of the forecasted annual amount of operating and capital expenses, debt and shareholder's equity required to support the Company's business. The Company estimates electricity usage and the costs to service each customer class to determine the appropriate rates to be charged to each customer class. The COS application is reviewed by the OEB and interveners and rates are approved based upon this review, including any revisions resulting from that review.

In the intervening years an Incentive Rate Mechanism application ("IRM") is filed. An IRM application results in a formulaic adjustment to distribution rates that were set under the last COS application. The previous year's rates are adjusted for the annual change in the Gross Domestic Product Implicit Price Inflator for Final Domestic Demand ("GDP IPI-FDD") net of a productivity factor and a "stretch factor" determined by the relative efficiency of an electricity distributor.

As a licensed distributor, the Company is responsible for billing customers for electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties. The Company is required, pursuant to regulation, to remit such amounts to these third parties, irrespective of whether the Company ultimately collects these amounts from customers.

The Company filed a COS rate application in 2018 for rates effective October 1, 2018 to April 30, 2019 for which a Decision and Rate order was issued September 27, 2018.

The Company filed an IRM in 2018 requesting a 1.45% inflationary increase to distribution rates effective May 1, 2019 to be implemented July 1, 2019 for the period of May 1, 2019 to April 30, 2020. The IRM was approved on July 9, 2019.

2. Basis of presentation (continued):

(g) Rate setting (continued):

ii) Distribution revenue (continued):

The Company filed an IRM and ICM in 2019 requesting a 1.55% inflationary increase to distribution rates and a substation upgrade rate rider effective May 1, 2020. The PUC elected to defer the implementation of rates to November 1, 2020 which the OEB approved October 8, 2020.

iii) Electricity rates:

The OEB sets Ontario electricity prices for low-volume consumers twice each year (May and November) based on an estimate of how much it will cost to supply the province with electricity for the next year. In 2017, the OEB set new lower Regulated Price Plan (RPP) prices established under the Ontario Fair Hydro Act, 2017.

On May 9, 2019, the Government of Ontario enacted Bill 87, the Fixing the Hydro Mess Act, 2019. The legislation amended the Ontario Rebate for Electricity Consumers Act, 2016, and the Ontario Fair Hydro Plan Act, 2017.

Effective November 1, 2019, the OEB set electricity prices under the RPP based on the estimated cost to supply the province with electricity. The Ministry of Energy, Northern Development and Mines set the amount of the rebate under the Ontario Rebate for Electricity Consumers Act, 2016 such that the monthly bill for a typical customer increased by the rate of inflation.

All remaining consumers pay the market price for electricity.

The Corporation is billed for the cost of the electricity that its customers use by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

3. Significant accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

(a) Financial instruments:

All financial assets and financial liabilities are measured at amortized cost. These financial instruments are recognized initially at fair value plus any directly attributable transaction costs. Subsequently, they are measured at amortized cost using the effective interest method less any impairment for the financial assets as described in note 3(e). The Company does not enter into derivative instruments.

Hedge accounting has not been used in the preparation of these financial statements.

Cash equivalents include short-term investments with maturities of three months or less when purchased.

3. Significant accounting policies (continued):

(b) Revenue recognition:

i) Electricity sales:

Electricity sales are recognized as the electricity is delivered to customers and includes the amounts billed to customers for electricity, including the cost of electricity supplied, distribution, and any other regulatory charges. Electricity revenue is recorded on the basis of regular meter readings and estimated customer usage since the last meter reading date to the end of the year. The related cost of power is recorded on the basis of power used.

For customer billings related to electricity generated by third parties and the related costs of providing electricity service, such as transmission services and other services provided by third parties, the Company has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

The difference between the amounts charged by the Company to customers, based on regulated rates, and the corresponding cost of electricity and related electricity service costs billed monthly by the Independent Electricity System Operator (“IESO”) is recorded as a settlement variance. In accordance with IFRS 14, this settlement variance is presented within regulatory balances on the balance sheets and within net movements in regulatory balances, net of tax on the statement of income and comprehensive income.

ii) Capital contributions:

Developers are required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. The developer is not a customer and therefore the contributions are scoped out of IFRS 15 “Revenue from Contracts with Customers”. Cash contributions are initially recorded as deferred revenue. When an asset other than cash is received as a capital contribution, the asset is initially recognized at its fair value, with a corresponding amount recognized as deferred revenue. The deferred revenue, which represents the Company's obligation to continue to provide the customers access to the supply of electricity, is amortized to income on a straight-line basis over the economic useful life of the constructed or contributed asset, which represents the period of ongoing service to the customer.

Certain customers are also required to contribute towards the capital cost of construction of distribution assets in order to provide ongoing service. These contributions fall within the scope of IFRS 15 Revenue from Contracts with Customers. The contributions are received to obtain a connection to the distribution system in order receive ongoing access to electricity. The Corporation has concluded that the performance obligation is the supply of electricity over the life of the relationship with the customer which is satisfied over time as the customer receives and consumes the electricity. Revenue is recognized on a straight-line basis over the useful life of the related asset.

iii) Rendering of services:

Revenue earned from the provision of services is recognized as the service is rendered.

3. Significant accounting policies (continued):

(b) Revenue recognition (continued):

iv) Conservation programs:

Incentive payments to which the Company is entitled from the IESO are recognized as revenue in the period when they are determined by the IESO and the amount is communicated to the Company.

c) Inventory:

Inventories consist of parts, supplies and materials held for the future capital expansion or replacement are valued at the lower of cost and net realizable value, with cost being determined on an average cost basis, and includes expenditures incurred in acquiring the material and supplies and other costs incurred in bringing them to their existing location and condition.

Net realizable value is the estimated selling price in the ordinary course of business, less estimated selling expenses.

(d) Property, plant and equipment:

Items of property, plant and equipment ("PP&E") used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the transition date less accumulated depreciation. All other items of PP&E are measured at cost, or, where the item is contributed by customers, its fair value, less accumulated depreciation.

Cost includes expenditures that are directly attributable to the acquisition of the asset. The cost of self-constructed assets includes the cost of materials, direct labour, and any other costs directly attributable to bringing the asset to a working condition for its intended use.

Borrowing costs on qualifying assets are capitalized as part of the cost of the asset based upon the weighted average cost of debt incurred on the Company's borrowings. Qualifying assets are considered to be those that take a substantial period of time to construct.

When parts of an item of property, plant and equipment ("PP&E") have different useful lives, they are accounted for as separate items (major components) of PP&E.

Gains and losses on the disposal of an item of PP&E are determined by comparing the proceeds from disposal, if any, with the carrying amount of the item of PP&E and are recognized net within other income in profit or loss.

Major spare parts and standby equipment are recognized as items of PP&E.

The cost of replacing a part of an item of PP&E is recognized in the net book value of the item if it is probable that the future economic benefits embodied within the part will flow to the Company and its cost can be measured reliably. In this event, the replaced part of PP&E is written off, and the related gain or loss is included in profit or loss. The costs of the day-to-day servicing of PP&E are recognized in profit or loss as incurred.

Depreciation is calculated over the depreciable amount and is recognized in income on a straight-line basis over the estimated useful life of each part or component of an item of PP&E. The depreciable amount is cost. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and in service.

3. Significant accounting policies (continued):

(d) Property, plant and equipment (continued):

The estimated useful lives are as follows:

Buildings	25 – 50 years
Transmission and distribution	15 – 60 years
Machinery and equipment	5 – 40 years

Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate.

(e) Impairment:

(i) Financial assets:

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset.

An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its current carrying amount (using prevailing interest rates), and the present value of the estimated future cash flows discounted at the original effective interest rate. Interest on the impaired assets continues to be recognized through the unwinding of the discount.

All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost the reversal is recognized in profit or loss.

(ii) Non-financial assets:

The carrying amounts of the Company's non-financial assets, other than inventories and deferred tax assets are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (the "cash-generating unit"). The recoverable amount of an asset or cash-generating unit is the greater of its value in use and its fair value less costs to sell. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset.

3. Significant accounting policies (continued):

(e) Impairment (continued):

(ii) Non-financial assets (continued):

An impairment loss is recognized if the carrying amount of an asset or its cash-generating unit exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss.

Impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depreciation, if no impairment loss had been recognized.

(f) Provisions:

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flows at a pre-tax rate that reflects current market assessments of the time value of money and the risks specific to the liability.

(g) Regulation:

The following regulatory treatments have resulted in accounting treatments which differ from those prescribed by IFRS for enterprises operating in an unrelated environment and regulated entities that have not adopted IFRS 14, Regulatory Deferral Accounts (IFRS 14).

(h) Regulatory deferral accounts:

The Company has determined that certain asset and liability balances arising from rate-regulated activities qualify for the application of regulatory accounting treatment in accordance with IFRS 14 and the accounting principles prescribed by the OEB in the Accounting Procedures Handbook for Electricity Distributors. Under rate-regulated accounting, the timing and recognition of certain expenses and revenues may differ from those otherwise expected under other IFRS in order to appropriately reflect the economic impact of regulatory decisions regarding the Company’s regulated revenues and expenditures. These amounts arising from timing differences are recorded as regulatory asset and liability balances on the Company’s statement of financial position, and represent existing rights and obligations regarding cash flows expected to be recovered from or refunded to customers, based on decisions and approvals by the OEB.

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. These amounts have been accumulated and deferred in anticipation of their future recovery in electricity distribution rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Company.

3. Significant accounting policies (continued):

(h) Regulatory deferral accounts (continued):

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in profit and loss. The debit balance is reduced by the amount of customer billings as electricity is delivered to the customer and the customer is billed at rates approved by the OEB for the recovery of the capitalized costs.

Regulatory deferral account credit balances are recognized if it is probable that future billings in an amount at least equal to the credit balance will be reduced as a result of rate-making activities. The offsetting amount is recognized in profit and loss. The credit balance is reduced by the amounts returned to customers as electricity is delivered to the customer at rates approved by the OEB for the return of the regulatory account credit balance.

The probability of recovery or repayment of the regulatory account balances are assessed annually based upon the likelihood that the OEB will approve the change in rates to recover or repay the balance. Any resulting impairment loss is recognized in profit and loss in the year incurred.

Regulatory deferral accounts attract interest at OEB prescribed rates. In 2020 the rate was 2.18% for the first two quarters of the year and 0.57% for the remainder of the year. Regulatory balances can be recognized for rate-setting and financial reporting purposes only if the OEB directs the relevant regulatory treatment or if future OEB direction is determined by management to be probable.

In the event that the disposition of these balances is assessed to no longer be probable based on management's judgment, the balances are recorded in the Company's statement of income and comprehensive income in the period when the assessment is made. Regulatory balances that do not meet the definition of an asset or liability under any other IFRS are segregated on the statement of financial position and on the statement of income and comprehensive income as net movements in regulatory balances, net of tax. The netting of regulatory debit and credit balances is not permitted.

The measurement of regulatory balances is subject to certain estimates and assumptions, including assumptions made in the interpretation of the OEB's regulations and decisions.

(i) Credit support for service delivery:

Credit support for service delivery represents cash deposits from electricity distribution customers as well as construction deposits.

Deposits from electricity distribution customers are applied against any unpaid portion of individual customer accounts. Customer deposits in excess of unpaid account balances are refundable to individual customers upon termination of their electricity distribution service. Customer deposits are also refundable to residential electricity distribution customers demonstrating an acceptable level of credit risk, as determined by the Company.

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. Cash contributions are initially recorded as credit support for service delivery, a current liability. Once the distribution system asset is completed or modified as outlined in the terms of the contract, the contribution amount is transferred to deferred revenue.

3. Significant accounting policies (continued):

(j) Deferred revenue and assets transferred from customers:

Certain customers and developers are required to contribute towards the capital cost of construction in order to provide ongoing service. When an asset is received as a capital contribution, the asset is initially recognized at its fair value, with the corresponding amount recognized as deferred revenue within non-current liabilities. Deferred revenue represents the Company's obligation to continue to provide customers access to the supply of electricity, and is amortized to income on a straight-line basis over the economic useful life of the acquired or contributed asset, which represents the period of ongoing service to the customer.

(k) Leased assets:

At inception of a contract, the Company assesses whether a contract is, or contains, a lease. A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. To assess whether a contract conveys the right to control the use of an identified asset, the Company assesses whether:

(i) The contract involves the use of an identified asset;
(ii) The Company has the right to obtain substantially all of the economic benefits from use of the asset throughout the period of use; and
(iii) The Company has the right to direct the use of the asset. The Company has this right when it has the decision-making rights that are most relevant to changing how and for what purpose the asset is used is predetermined, the Company has the right to direct the use of the asset if either:

a) The Company has the right to operate the asset; or
b) The Company designed the asset in a way that predetermines how and for what purposes it will be used.

Short-term leases and low value assets

The Company has elected not to recognize right-of-use assets and lease liabilities for short-term leases that have a lease term of 12 months or less and leases of low-value assets. The Company recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

3. Significant accounting policies (continued):

(l) Payment in lieu of taxes:

The Company is currently exempt from taxes under the Income Tax Act (Canada) and the Ontario Corporations' Tax Act (collectively the "Tax Acts"). Under the *Electricity Act*, 1998, the Company makes payments in lieu of corporate taxes to the Ontario Electricity Financial Company ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Income Tax Act (Canada) and the Company's Tax Act (Ontario) as modified by the Electricity Act, 1998, and related regulations. Prior to October 1, 2001, the Company was not subject to income or capital taxes.

PILs comprises current and deferred payments in lieu of income tax. PILs recognized in income and loss except to the extent that it relates to items recognized directly in either comprehensive income or equity, in which case, it is recognized in comprehensive income or in equity.

Current PILS is the expected amount of tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred PILs comprise the net tax effects of temporary differences between the tax basis of assets and liabilities and their respective carrying amounts for accounting purposes, as well as for tax losses available to be carried forward to future years that are likely to be realized.

Deferred PILs assets and liabilities are measured using enacted or substantively enacted tax rates, at the reporting date, expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred PILs assets and liabilities of a change in tax rates is recognized in income in the year that includes the date of enactment or substantive enactment.

A deferred PILs asset is recognized to the extent that it is probable that future taxable income will be available against which the temporary difference can be utilized. Deferred PILs assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

3. Significant accounting policies (continued):

(m) Critical accounting estimates and judgments:

The Company makes estimates and assumptions about the future that affect the reported amounts of assets and liabilities. Estimates and judgments are continually evaluated based on historical experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. In the future, actual experience may differ from these estimates and assumptions.

The effect of a change in an accounting estimate is recognized prospectively by including it in comprehensive income in the period of the change, if the change affects that period only; or in the period of the change and future periods, if the change affects both.

The estimates and assumptions that have a significant risk of causing material adjustment to the carrying amounts of assets and liabilities within the next financial year are discussed below.

Fair value of financial instruments:

The Company determines the fair value of financial instruments that are not quoted in an active market, using valuation techniques. Those techniques are significantly affected by the assumptions used, including discount rates and estimates of future cash flows. In that regard, the derived fair value estimates cannot always be substantiated by comparison with independent markets and, in many cases, may not be capable of being realized immediately.

The methods, and assumptions applied, and the valuation techniques used, for financial instruments that are not quoted in an active market are disclosed in note 16.

Payment in lieu of taxes:

The Company periodically assesses its liabilities and contingencies related to PILs for all years open to audit based on the latest information available. For matters where it is probable that an adjustment will be made, the Company records its best estimate of the tax liability including the related interest and penalties in the current PILs provision. Management believes they have adequately provided for the probable outcome of these matters; however, the final outcome may result in a materially different outcome that the amount included in the PILs liabilities.

Useful lives of depreciable assets:

Management reviews the useful lives of depreciable assets at each reporting date. At December 31, 2020, management assesses that the useful lives represent the expected utility of the assets to the Company. The carrying amounts are analyzed in note 6. Actual results, however, may vary due to technical obsolescence, particularly for software and electronic equipment.

3. **Significant accounting policies (continued):**

(m) Critical accounting estimates and judgments (continued):

Impairment:

An impairment loss is recognized for the amount by which an asset's carrying amount exceeds its recoverable amount, which is the higher of fair value less cost to sell and value-in-use. To determine the value-in-use, management estimates expected future cash flows from each asset or cash generating unit and determines a suitable interest rate in order to calculate the present value of those cash flows. In most cases, determining the applicable discount rate involves estimating the appropriate adjustment to market risk and the appropriate adjustment to asset-specific risk factors. In the process of measuring expected future cash flows management makes assumptions about future operating results. These assumptions relate to future events and circumstances.

4. **Accounts receivable:**

	2020	2019
Trade receivables	$ 5,392,292	$ 5,104,625
Other receivables	346,002	329,151
	$ 5,738,294	$ 5,433,776

Included in the receivables balance is an allowance for doubtful accounts in the amount of $348,864 (2019 - $353,384)

5. **Inventory:**

The amount of inventories consumed by the Company and recognized as an expense during 2020 was $272,313 (2019 - $326,444).

	2020	2019
Stores	$ 1,003,436	$ 951,738
Wire and cable	695,548	499,695
Poles	321,134	278,051
	$ 2,020,118	$ 1,729,484

6. Property, plant and equipment:

(a) Cost or deemed cost:

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2020	$ 26,075,741	$ 73,567,004	$21,087,433	$1,275,692	$122,005,870
Additions	139,988	5,019,661	726,078	3,544,598	9,430,325
Balance at December 31, 2020	$ 26,215,729	$ 78,586,665	$21,813,511	$4,820,290	$131,436,195

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2019	$ 25,883,626	$ 68,540,300	$20,470,714	$ 232,287	$115,126,927
Additions	192,115	5,026,704	616,719	1,043,405	6,878,943
Balance at December 31, 2019	$ 26,075,741	$ 73,567,004	$21,087,433	$ 1,275,692	$122,005,870

(b) Accumulated depreciation:

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 31, 2020	$ 4,087,214	$12,335,673	$ 5,483,125	$ –	$ 21,906,012
Depreciation charge	692,833	2,465,897	994,487	–	4,153,217
Balance at December 31, 2020	$ 4,780,047	$14,801,570	$ 6,477,612	$ –	$ 26,059,229

	Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
Balance at January 1, 2019	$ 3,400,451	$ 9,987,386	$ 4,507,503	$ –	$ 17,895,340
Depreciation charge	686,763	2,348,287	975,622	–	4,010,672
Balance at December 31, 2019	$ 4,087,214	$12,335,673	$ 5,483,125	$ –	$ 21,906,012

Contributed tangible assets:

Contributed tangible assets have been recognized at a fair market value at the date of contribution. The value of contributed assets at the end of the year is $4,829,126 (2019 - $4,294,948), comprised of distribution infrastructure.

6. Property, plant and equipment (continued):

(c) Carrying amounts:

		Land and buildings	Transmission & distribution	Plant & equipment	Construction -in- Progress	Total
At December 31, 2020	$	21,435,682	63,785,095	15,335,899	4,820,290	105,376,966
At December 31, 2019	$	21,987,527	61,231,331	15,604,308	1,275,692	100,099,858

(d) Security:

At December 31, 2020, properties with a carrying amount of $105,376,966 (2019 - $100,099,858) are subject to a general security agreement.

7. Payments in lieu of income taxes:

Payment in lieu of taxes expense (recovery):

Current PILs Expense:

		2020		2019
Current payments in lieu of income tax	$	76,523	$	85,514
Adjustment to prior years		–		41,444
Payment in lieu of income tax expense	$	76,523	$	126,958

Deferred PILs Expense:

		2020		2019
Origination and reversal of timing differences	$	677,000	$	638,000
Payment in lieu of income tax expense	$	753,523	$	764,958

7. Payments in lieu of income taxes (continued):

Reconciliation of effective tax rate:

	2020	2019
Net income being total comprehensive income for the year	$ 2,834,185	$ 3,167,171
Statutory rate	26.5%	26.5%
Income tax	751,059	839,300
Increase (decrease) resulting from:		
Permanent difference	1,563	1,584
Adjustment to prior year's recovery	–	(76,000)
Other	901	74
	$ 753,523	$ 764,958

Significant components of the Company's deferred tax balances are as follows:

	2020	2019
Deferred tax assets (liabilities):		
Plant and equipment	$ (2,424,000)	$ (1,882,000)
Reserves	92,000	94,000
CMT credit	366,000	290,000
Non-capital loss carry forward	579,000	788,000
	$ (1,387,000)	$ (710,000)

8. Regulatory deferral account balance:

The following is a reconciliation of the carrying amount for each class of regulatory deferral account balances:

	January 1, 2020	Balances arising in the period	Recovery/ reversal	December 31, 2020	Remaining recovery/ reversal period (years)
Regulatory deferral account debit balances					
Settlement Variance	$ 2,439,984	$ (56,265)	$ 245,703	$2,629,422	<1
Deferred taxes	966,000	–	920,000	1,886,000	
LRAMVA	307,609	1,439	(253,897)	55,151	<1
Total amount related to regulatory deferral account debit balances	$ 3,713,593	$ (54,826)	$ 911,805	$4,570,573	
Regulatory deferral account credit balances					
Deferred Taxes	$ (256,000)	$ –	$(243,000)	$ (499,000)	
Stranded Meters	(34)	34	–	–	
Smart Meter Entity Charges	(23,822)	(276)	(59)	(24,157)	<1
Regulatory Asset Recovery Account Phase 5-9	(567,447)	(32,584)	600,031	–	<1
Regulatory Asset Recovery Account Phase 10	(591,756)	175,023	405,301	(11,432)	<1
CGAAP Accounting Changes	2	(2)	–	–	
Accelerated CCA	–	(284,105)	–	(284,105)	
Total amount related to regulatory deferral account credit balances	$ (1,439,057)	$ (141,910)	$ 762,273	$ (818,694)	

	January 1, 2019	Balances arising in the period	Recovery/ reversal	December 31, 2019	Remaining recovery/ reversal period (years)
Regulatory deferral account debit balances					
Settlement Variance	$ (672,655)	$ 84,433	$3,028,206	$2,439,984	<1
Deferred taxes	150,000	–	816,000	966,000	
LRAMVA	426,609	11,159	(130,159)	307,609	<1
Total amount related to regulatory deferral account debit balances	$ (96,046)	$ 95,592	$3,714,047	$3,713,593	
Regulatory deferral account credit balances					
Deferred Taxes	$ (78,000)	$ –	$(178,000)	$ (256,000)	
Stranded Meters	(34)	–	–	(34)	<1
Smart Meter Entity Charges	(29,071)	412	4,837	(23,822)	<1
Regulatory Asset Recovery Account Phase 5-9	(2,557,512)	–	1,990,065	(567,447)	<1
Regulatory Asset Recovery Account Phase 10	–	70,846	(662,602)	(591,756)	<1
CGAAP Accounting Changes	2	–	–	2	1
Total amount related to regulatory deferral account credit balances	$ $ (2,664,615)	$ 71,258	$1,154,300	$ (1,439,057)	

8. Regulatory deferral account balance (continued):

The regulatory deferral account balances are recovered or settled through rates set by the OEB which are determined using estimates of future consumption of electricity by its customers. Future consumption is impacted by various factors including the economy and weather. The Company has received approval from the OEB to establish its regulatory deferral account balances.

Group 1 deferral and variance accounts (Group 1 accounts) track the differences between the costs that a distributor is billed for certain IESO and host distributor services (including the cost of power) and the associated revenues that the distributor receives from its customers for these services. The total net difference between these costs and revenues is disposed to customers through a temporary charge or credit known as a rate rider.

The OEB requires the Company to estimate its income taxes when it files a COS application to set its rates. As a result, the Company has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from/paid back to its customers. This balance will fluctuate as the Company's deferred tax balance fluctuates.

9. Deferred revenue:

	Distribution assets	Construction in-Progress	Total
Cost or deemed cost			
Balance at January 1, 2020	$ 4,630,407	$ –	$ 4,630,407
Additions	658,166	–	658,166
Balance at December 31, 2020	$ 5,288,573	$ –	$ 5,288,573
Balance at January 1, 2019	$ 3,518,564	$ –	$ 3,518,564
Additions	1,111,843	–	1,111,843
Balance at December 31, 2019	$ 4,630,407	$ –	$ 4,630,407

	Distribution assets	Construction in-Progress	Total
Accumulated depreciation			
Balance at January 1, 2020	$ 335,459	$ –	$ 335,459
Depreciation	123,988	–	123,988
Balance at December 31, 2020	$ 459,447	$ –	$ 459,447
Balance at January 1, 2019	$ 233,597	$ –	$ 233,597
Depreciation	101,862	–	101,862
Balance at December 31, 2019	$ 335,459	$ –	$ 335,459
Carrying amounts			
At December 31, 2020	$ 4,829,126	$ –	$ 4,829,126
At December 31, 2019	4,294,948	–	4,294,948

9. Deferred revenue (continued):

Deferred revenue relates to capital contributions received from customers and others. The amount of deferred revenue received from customers during the year is $658,166 (2019 - $1,111,843). Deferred revenue is recognized as revenue on a straight-line basis over the life of the related asset for which the contribution was received.

10. Long-term debt:

	2020	2019
Notes payable:		
(i) Ontario Infrastructure smart meter loan	$ 3,015,290	$ 3,331,997
(ii) Ontario Infrastructure building loan	17,331,453	17,946,697
(iii) Ontario Infrastructure distribution loan	13,126,402	13,560,934
(iv) Ontario Infrastructure construction loan	5,800,000	–
(v) Note payable to parent company, PUC Inc.	26,534,040	26,534,040
	65,807,185	61,373,668
Current portion of long-term debt	(1,727,219)	(1,366,680)
	$ 64,079,966	$ 60,006,988

i) Smart Meter Loan with Ontario Infrastructure and Lands Corporation (OILC): Reducing Debenture Facility, amortization period of 15 years to July 17, 2028. The loan interest rate of 3.82%. Interest of $119,245 (2019 - $131,193) was paid and expensed during the year. The loan is payable in the amount of $220,496 semi-annual principal and interest. Security is in the form of a second ranking general security agreement.

ii) Land and Building Loan with OILC: Reducing Debenture Facility, amortization period of 25 years to October 1, 2038. The loan interest rate of 4.57%. Interest of $807,576 (2019 - $834,821) was paid and expensed during the year. The loan is payable in the amount of $118,568 monthly principal and interest. Security is in the form of a first charge over the Company's land and building and a third ranking general security agreement.

iii) Electric Distribution Infrastructure Loan with OILC: The construction loan was converted to long term debt in 2016, at an interest rate of 3.47%, repayable over 25 years by a blended principal and interest payment of $74,852 monthly maturing on May 16, 2041. Interest of $463,697 (2019 - $478,495) was paid and expensed during the year. Security is in the form of a fourth ranking general security agreement and a guarantee and assignment of shares from the company's shareholder, PUC Inc.

iv) Electric Distribution Infrastructure Loan with OILC: Temporary construction loan with a variable interest rate. Interest of $33,436 was paid and expensed during the year and $95,646 was capitalized. The construction loan was converted to long debt on January 15, 2021, at an interest rate of 2.11%, repayable over 15 years by a blended principal and interest payment of $37,618 monthly maturing on January 15, 2036. Security is in the form of a fifth ranking general security agreement and a guarantee and assignment of shares from the company's shareholder, PUC Inc.

10. Long-term debt (continued):

v) Note payable to parent company, PUC Inc., bears interest payable quarterly at rates periodically negotiated and principal payable one year after demand. The average interest rate for 2020 was 6.1% (2019 – 6.1%). The balance outstanding for 2019 is $26,534,040 (2019 - $26,534,040).

Subsequent to yearend, on February 16, 2021 the Company drew on their drawdown certificate with OILC in the amount of $4 million to cover infrastructure upgrades that were paid using cash from Services. The amounts from the drawdown went to repay part of the balance payable to related party. The amount remains as a construction loan with a variable interest rate until it is transferred into a term loan.

Principal payments on the long-term debt are as follows:

2021	$ 1,727,219
2022	1,820,265
2023	1,888,541
2024	1,959,526
2025	2,033,332
2026 - 2042	56,378,302
	$ 65,807,185

Reconciliation of movements of liabilities to cash flows arising from financing activities:

	2020	2019
Long term debt - beginning	$ 61,373,668	$ 62,686,347
Less: cash outflows for principal repayments	(1,366,483)	(1,312,679)
Add: cash inflow for new debt	5,800,000	–
	$ 65,807,185	$ 61,373,668

11. Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers, as well as construction deposits.

Deposits from electricity distribution customers are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Company in accordance with policies set out by the OEB or upon termination of their electricity distribution service. The balance at December 31, 2020 is $712,937 (2019 - $1,067,552).

12. Share capital:

	2020	2019
Authorized:		
Unlimited number of special shares, non-voting, non-cumulative		
Redeemable at $10,000 per share		
10,000 Common shares		
Issued and outstanding:		
8,612 common shares	$ 20,062,107	$ 20,062,107

13. Electricity sales:

The Corporation generates revenue primarily from the sale and distribution of electricity to its customers. In the following table, revenue from contracts with customers is disaggregated by type of customer.

	2020	2019
Electricity sales	$ 85,083,387	$ 74,373,612
Distribution revenue	19,032,237	19,071,168
Total revenue from contracts with customers	$ 104,115,624	$ 93,444,780

	2020	2019
Residential	$ 54,222,874	$ 44,731,622
Commercial	49,263,706	48,012,954
Street lights	629,044	700,204
	$ 104,115,624	$ 93,444,780

14. Other operating revenue:

Other income comprises:

	2020	2019
Conservation and demand management	$ 4,731,173	$ 4,031,628
Service work related to distribution operations	1,501,205	1,498,284
Pole attachment and duct rentals	828,248	791,218
Account-related charges	296,114	173,679
Other	150,092	149,986
Capital contributions from customers amortized to revenue	123,988	101,862
Gain on disposal of property, plant and equipment	–	500
Total other income	$ 7,630,820	$ 6,747,157

15. Finance income and expense:

	2020	2019
Interest income	$ 459	$ 2,919
Interest expense on long-term debt	2,946,885	3,063,085
Other interest and carrying charges	240,796	70,345
	3,187,681	3,133,430
Net finance costs recognized in profit or loss	$ 3,187,222	$ 3,130,511

16. Commitments and contingencies:

i) General:

From time to time, the Company is involved in various litigation matters arising in the ordinary course of its business. The Company has no reason to believe that the disposition of any such current matter could reasonably be expected to have a materially adverse impact on the Company's financial position, results of operations or its ability to carry on any of its business activities.

ii) General Liability Insurance:

The Company is a member of the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE). MEARIE is a pooling of public liability insurance risks of many of the LDCs in Ontario. All members of the pool are subjected to assessment for losses experienced by the pool for the years in which they were members, on a pro-rata basis based on the total of their respective service revenues. As at December 31, 2020, no assessments have been made.

iii) Letter of Guarantee:

The Company maintains a $5,000,000 letter of guarantee with its Bank in favor of the IESO.

17. Related party transactions:

(a) Parent, ultimate controlling party, and other related parties:

The sole shareholder of the Company is PUC Inc., which in turn is wholly-owned by the Corporation of the City of Sault Ste. Marie. The City produces financial statements that are available for public use. Other related parties include PUC Services Inc. (Services), Public Utilities Commission of the City of Sault Ste. Marie (Utility), and Northern Waterworks Inc (NWI).

17. Related party transactions (continued):

(b) Key management personnel:

The key management personnel of the Company have been defined as members of its board of directors and is summarized below:

	2020	2019
Directors' fees	$ 12,035	$ 9,870

(c) Transactions with ultimate parent (the City):

In the year, the Company had the following significant transactions with its ultimate parent, a government entity:

The Company delivers electricity to the City throughout the year for the electricity needs of the City and its related organizations. Electricity delivery charges are at prices and under terms approved by the OEB. The amount charged to the City for electricity consumed by streetlights is $631,183 (2019 - $635,219) and for other electricity consumption is $3,915,844 (2019 - $4,277,141).

(d) Transaction with PUC Inc.:

The Company declared dividends on its common shares held by PUC Inc. in the amount of $610,080 (2019 - $900,000). This amounts to $70.84 per share (2019 - $104.51 per share). Dividends payable to PUC Inc. at the end of the year amount to $610,080 (2019 - $900,000).

(e) Transactions with Services:

The Company has a management, operation and maintenance agreement with Services, which has been extended to November 30, 2022, under which Services manages, controls, administers and operates the business of the Company. During the year, management fees were charged by Services in the amount of $5,318,112 (2019 - $4,655,272).

The Company pays interest on its payable balance to Services at the OEB prescribed short-term borrowing rate on its average monthly balance. Interest of $155,336 (2019 – $68,363) was paid during the year.

The payable balance to Services at December 31, 2020 amounts to $10,688,540 (2019 - $9,041,731).

These transactions are in the normal course of operations and are measured at the exchange amount which is the amount of consideration agreed to by the related parties.

(f) Transactions with NWI:

The Company is related to NWI through common ownership group. There were no transactions with NWI during the year (2019 - $NIL).

18. Financial instruments and risk management:

(a) Fair value disclosure:

Cash and cash equivalents are measured at fair value. The carrying values of receivables, and accounts payable and accrued charges approximate fair value because of the short maturity of these instruments. The carrying value of the customer deposits approximates fair value because the amounts are payable on demand.

(b) Financial risks:

The Company understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Company's exposure to a variety of risks such as credit risk, interest rate risk, and liquidity risk, as well as related mitigation strategies are discussed below.

i) Credit risk:

Financial assets carry credit risk that a counterparty will fail to discharge an obligation which could result in a financial loss. Financial assets held by the Company, such as accounts receivable, expose it to credit risk. The Company earns its revenue from a broad base of customers located in the City. No single customer accounts for a balance in excess of 2.53% of total accounts receivable.

The carrying amount of accounts receivable is reduced through the use of an allowance for impairment and the amount of the related impairment loss is recognized in net income. Subsequent recoveries of receivables previously provisioned are credited to net income. The balance of the allowance for impairment at December 31, 2020 is $348,864 (2019 - $353,384).

The Company's credit risk associated with accounts receivable is primarily related to payments from distribution customers. The Company has over 33 thousand customers, the majority of whom are residential. Credit risk is managed through collection of security deposits from customers in accordance with directions provided by the OEB. As at December 31, 2020, the Company holds security deposits in the amount of $712,937 (2019 - $1,067,552).

As a result of the COVID-19 pandemic, certain of the Corporation's customers have experienced loss of employment, business shut-downs and other disruptions. The extension of the OEB's winter disconnection ban negatively impacted the Corporation's ability to exercise the full extent of its collection tools to manage the credit risk. In response to the increased collection risk, the Corporation has increased its loss allowance for expected credit losses to adjust for the higher level of expected customer defaults on accounts receivable. The Corporation has estimated the expected credit losses using its historical loss rates and recent trends for customer collections along with current and forecasted economic conditions and data. There is a greater degree of estimation uncertainty over this loss estimate than in 2019. To support residential and small business customers struggling to pay their energy bills, the Government of Ontario provided funding for the COVID-19 Energy Assistance Program ("CEAP"). The Corporation was allocated a portion of this funding and actively participated in the program.

18. Financial instruments and risk management (continued):

ii) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Company currently does not have any material commodity or foreign exchange risk. The Company is exposed to fluctuations in interest rates as the regulated rate of return for the Company's distribution business is derived using a complex formulaic approach which is in part based on the forecast for long-term Government of Canada bond yields. This rate of return is approved by the OEB as part of the approval of distribution rates.

iii) Liquidity risk:

The Company monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Company's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Company has access to a $4,500,000 credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they come due. The COVID-19 pandemic has placed increased liquidity pressure on the Corporation. The Corporation's currently available liquidity is expected to be sufficient to address any reasonably foreseeable impacts that the COVID-19 pandemic may have on the Corporation's cash requirements.

As at December 31, 2020, no amounts had been drawn under the Company's credit facilities.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days.

iv) Capital disclosures:

The main objectives of the Company, when managing capital, are to ensure ongoing access to funding to maintain and improve the electricity distribution system, compliance with covenants related to its credit facilities, prudent management of its capital structure with regard for recoveries of financing charges permitted by the OEB on its regulated electricity distribution business, and to deliver the appropriate financial returns.

The Company's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2020, shareholder's equity amounts to $36,873,347 (2019 - $34,725,765) and long-term debt amounts to $65,807,185 (2019 - $61,373,668).

APPENDIX I

2021 PUC

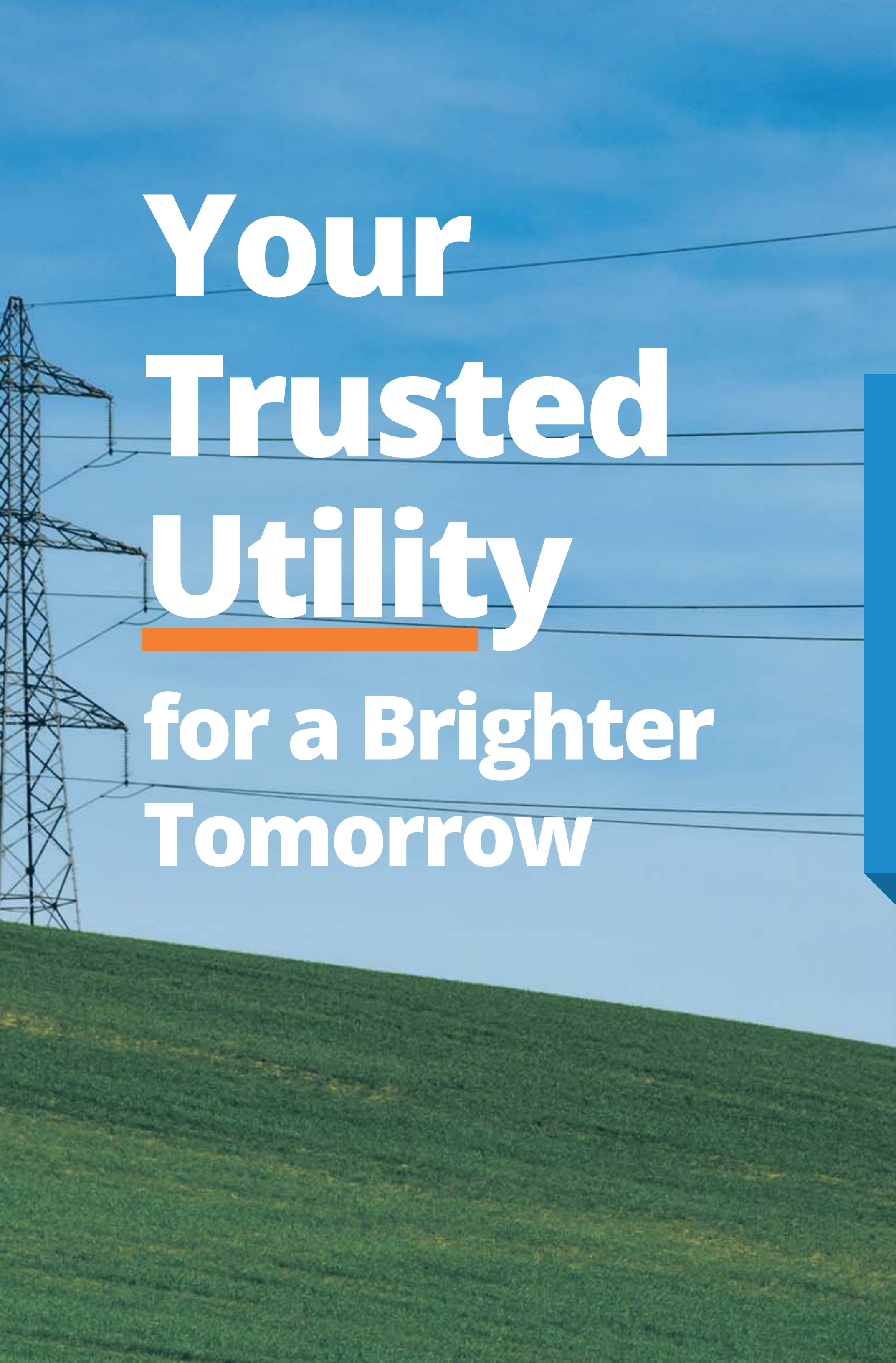
Sustainability

Report

PUC SERVICES INC. | SUSTAINABILITY REPORT 2021

Realizing our Vision

PUC SERVICES



Your Trusted Utility for a Brighter Tomorrow

> "Today more than ever, our focus is on a sustainable PUC that is developing strategies to lower our carbon footprint, support our communities, and maintain exceptional customer service well into the future."
>
> **— Jim Boniferro, Chair, PUC Services/PUC Inc.**

PUC is proud to present our 2021 Sustainability Report.

This report provides an overview of how we are growing with purpose, lowering our carbon footprint, supporting our customers in the communities we serve, and protecting the health and safety of our employees.

Table of Contents

Click on buttons like these in the report to watch a video.

VIDEO

Message from Jim P Boniferro

Chair, PUC Services Inc. / PUC Inc.

PUC Services Inc./PUC Inc.'s Chair Jim Boniferro, has been an integral player in laying the groundwork for the sustainable, growing PUC that we know today. As his term as Chair comes to an end, PUC would like to thank Jim for his strong leadership, strategic vision, and dedication to PUC over the past nine years.

Transformation through Curiosity and Innovation

The PUC and the utility industry were drastically different when I was elected Chair of the PUC Services Inc. Board of Directors in 2014. PUC was a company made up of exceptional employees, providing electrical and water distribution to customers in the Algoma region. We were not aware of the many challenges about to face our organization, such as smart technology, climate change impacts on utilities and a global pandemic that would impact every facet of our lives.

Today, the environment in which PUC operates is constantly changing. Different customer expectations paired with improved environmental pressures has required PUC to be responsive and adaptable, transforming at a rapid pace to meet the needs of today - and being prepared for tomorrow. Our commitment to being a strong leader in the communities we serve has added a new dimension to our day-to-day operations and our long-term vision.

Building a strong, diverse and experienced Board was job one. The process of adapting had to begin at the Board level. PUC has found our identity as a growing, strategic company whose vision is to improve communities through curiosity and innovation. The Board worked to develop a strategic plan that clearing defined what growth, vision and the future of the organization would look like. Staff embraced this strategic direction and brought it to life.

We know where we're going – and we have a clear plan to get there. The journey hasn't always been easy, but it is so rewarding to see the progress we have made – and even more importantly – the excitement and optimism about our future.

The Shift to Strategic

PUC has always been and will continue to be an extremely important part of the communities we serve. The difference I see, and one that the Board and PUC staff have strived for over the past decade, is a shift in thinking around everything we do.

We had to figure out what we wanted to be and where we fit into the communities and the industries as we grew.

Collectively, we started asking questions like "how can we do this differently?", "How will this decision make PUC more sustainable and add value?", "How will this support the communities we serve into the future?", and "How will this improve our customers quality of life?" In short, we started being more curious.

Establishing a clear vision, common goal and a strategic plan that was understood throughout the organization is what ultimately led to a more sustainable PUC. It allowed us to more effectively measure our activities and ensure they were aligned with our vision and strategic plan.

Focus on Sustainability

Today more than ever, our focus is on a sustainable PUC that is developing strategies to lower our carbon footprint, support our communities, and maintain exceptional customer service well into the future.

Whether it is a health and safety initiative, a financial investment, community involvement, or an operational decision, we are always asking ourselves "how does it make the organization more sustainable, improve customer experience and tie into our long-term vision?"

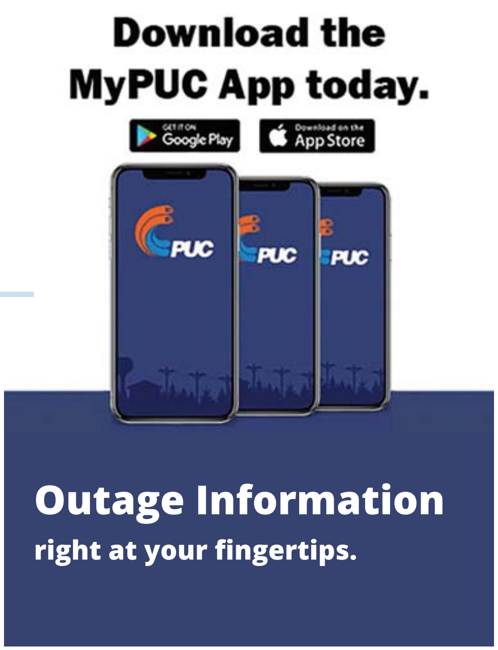
'Thinking big' is now part of PUC's culture and is woven into who we are as a company. We are now less reactive and more proactive in our decision making and planning. That to me, is one of the biggest positive changes I have seen over the years.

Curiosity and Innovation

PUC's vision to improve the community through curiosity and innovation is reflected in so many current examples. The Sault Smart Grid, Watertight Lining Solutions Inc, and the MyPUC App are just a few projects that demonstrate our vision coming to life.

The Sault Smart Grid is quite literally using innovation to change the way we deliver electricity, and it is the first community-wide project of its kind in Canada.

Customers can now report outages quickly and easily on the MyPUC App, and that results in quicker response times to restore power. Updates provided through the MyPUC App improves customer experience by eliminating the unknown.



We are using innovative technology to renew aging water infrastructure that saves time and money, and reduces the impact on both our customers and the environment. This allows us to continue to provide safe, reliable drinking water.

These examples show how our vision and our values drive our decision and how we change as a company.

Community Partner

Our annual dividends to the shareholder have been at record levels in recent years, and this is something we are very proud of. But it goes so far beyond that. We are no longer just a regulated utility service. We are driving positive change in the community, and are seen as a leader locally, provincially - and even nationally.

We now work with our customers and stakeholders in a different way. We have come a long way to be recognized as a community partner; there is a clearer understanding of that role. We are constantly thinking of how we can better our community, providing support to community members on both large and small scale projects.

This was most recently reflected in the award recognition we received by Algoma Public Health for our efforts to help community members during the COVID-19 pandemic.

Looking to the Future

There is always more work to do.

I am looking forward to seeing continued growth and what new innovative and curious projects PUC will take on in the future. No doubt, PUC will pursue opportunities that will be beneficial to the current operation, and I look forward to seeing what those may be.

When new opportunities come up, whether it be in the community or outside of the community, I want people to think "that's a good opportunity for PUC". I know it is already happening, and that makes me very proud of my role over the years to have been a small part in laying the groundwork for a bright future for an organization that means so much to our community.

A conversation with Rob Brewer

President and CEO, PUC Services Inc.

Q. Although the pandemic continued to be a big factor in 2021, PUC was extremely active on many fronts. What was your overarching goal for the year?

I really believe our goal over the past year was to continue to realize our vision to be a sustainable organization and to be a leader in supporting and giving back to our community.

As a growing, strategic organization, with a clear definition of our initiatives and how we execute on those, we have been better able to be sustainable and to support our community.

Q. Why is it so important as a business to give back to the community?

There are many reasons. This is the community we live in, these are our customers and future customers. I personally believe there is a moral obligation to assist if you can and PUC was one of the least impacted businesses during the pandemic. We tried to help those more impacted whether it was purchasing local restaurants gift cards as support to employees or helping the community during the vaccination process.

Last year we tried to be more direct in our support. We used to work through umbrella charity groups, but during the pandemic we reached directly to access those local groups so we could have a more immediate impact.

Q. How successful were you?

I think the vaccination support and the children's programs were very successful. We also were very honored when Algoma Public Health named us a 2021 Public Health Champion. We weren't looking for the recognition, as our focus was helping behind the scenes, but it was very much appreciated.

Q. On the business side, what were the key projects for 2021?

It's been a massive year!

Sault Smart Grid:

This was approved by the OEB, a first of its kind, possibly in North America but in Canada for sure. That was a huge accomplishment. It was a regulatory first to get that done. It was the start of our journey and then we had to make it happen. We've brought in the contractors to get early work done including the initial first phase of engineering, finalizing contracts and now we are getting to construction as weather allows. It is quite the endeavor.

PUC Transmission LP:

This project will have a profound impact on the Sault, dramatically impacting our environment and the quality of air in the region. The community is very fortunate to have a major investment from the Algoma Steel Mill to the tune of $700-$800 million dollars and Federal government support, which we also appreciate.

PUC will construct transmission facilities that will provide power to Algoma Steel Inc.'s new state-of-the-art electric arc furnaces, which they say will lead to a 70 per cent reduction in carbon emissions. Not only was it a good business opportunity for PUC to get involved, but it's the right thing to do. We were motivated to help make it happen because it really is an important transformation for the community. We had an old school steel mill that's been through a number of bankruptcies, riding the boom bust cycle. This investment now turns it into one of the most efficient steel mills out there.

Green steel (meaning the process is green) will set Algoma Steel and the community on a stable financial footing, probably for the next two generations. It also brings significant benefits to PUC and returns to Sault Ste. Marie. This will double our electrical asset – rate base.

Sault Area Hospital:
This project, now under construction, allows us to provide $3 million in energy savings to Sault Area Hospital through an innovative program we introduced. Through the use of battery energy storage, it will also improve power reliability and quality. What better place for the dollars to be than the hospital and what a great opportunity to help too.

Watertight Lining Solutions Inc.:
Our new company uses robotic technology to spray in place polymer lining to give water pipes added strength, higher quality water, regenerate tired assets and extend its life without digging and replacing. There is immense growth opportunity here. We have gone through the testing process and hope to launch more broadly beginning in December of this year.

Q. What's ahead for PUC?

There's a lot of work ahead this year for all the projects I mentioned, to keep us growing and continuing to be sustainable, bringing returns to the city and supporting our community.

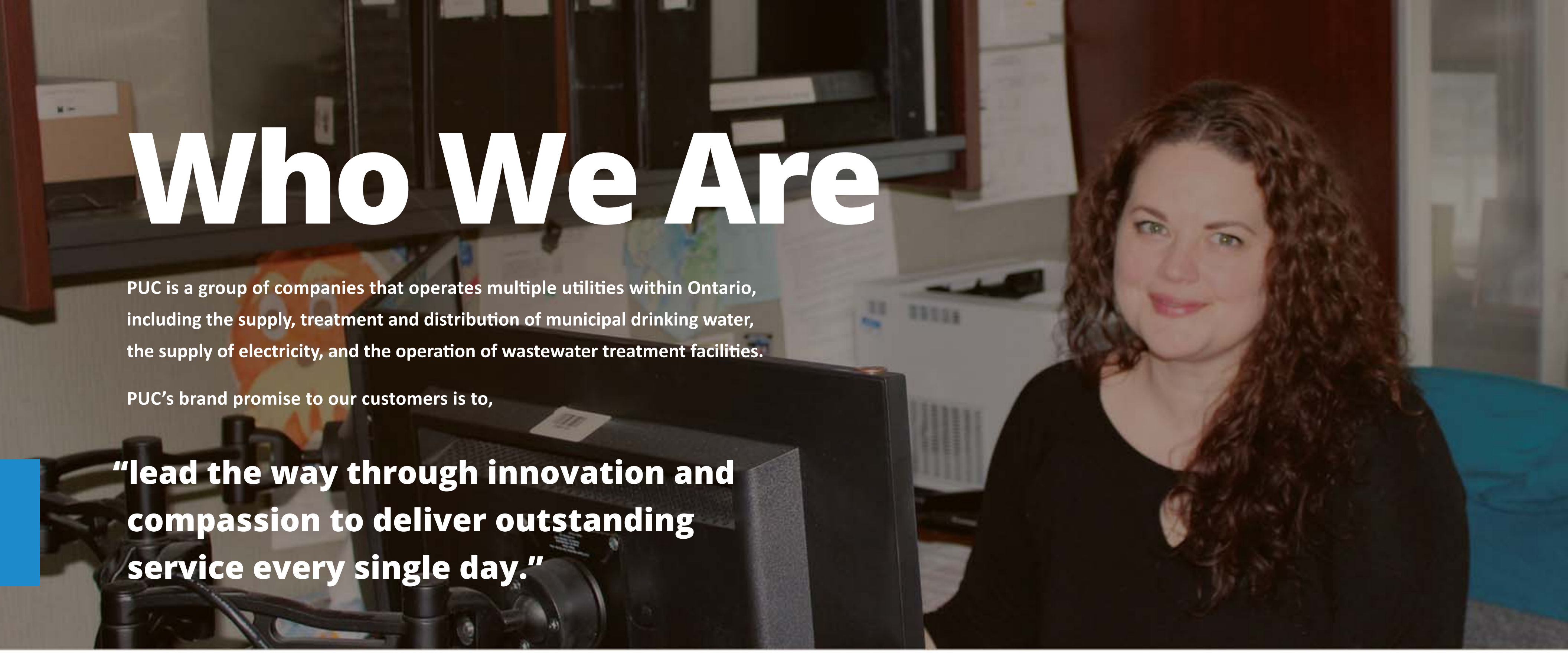
We are also looking forward to getting people back into the office, put the screens down for a bit and actually talk to people face to face. We will also help our employees manage the anxiety that comes with those changes.

Q. What do you see as the future challenges for utilities?

I think utilities across the province all have significant asset replacement challenges, requiring them to perform well so they can make the necessary reinvestments into infrastructure and continue to be a sustainable utility. We are fortunate that we have been performing well so that we can make those needed capital program investments.

On the water side, there are enormous infrastructure challenges. Our replacement value of assets on the water side is almost a billion dollars. A big part of that is planned for the next 20 years so we have ramped up our programs and they will continue to grow to upwards of $10 million a year and more. Many of the assets have a 70-year life span but here in Sault they were put in at the same time, so we are starting to see that need and get ahead of it. Our watermain lining program will help extend the life of some of that infrastructure and put replacement out possibly 30 years helping to offset other necessary infrastructure costs.

Talent is a challenge for everyone – maybe not as much for utilities but still finding tradespeople has become more and more of a challenge. Finding talented executives is another issue. At PUC, we are fortunate now but as you look to retirements in the horizon, it's something everyone needs to be looking at. By continuing with a strategic focus on sustainability, I am confident PUC will continue to serve the community well for decades to come.



Who We Are

PUC is a group of companies that operates multiple utilities within Ontario, including the supply, treatment and distribution of municipal drinking water, the supply of electricity, and the operation of wastewater treatment facilities.

PUC's brand promise to our customers is to,

"lead the way through innovation and compassion to deliver outstanding service every single day."

OUR MISSION

We are a community leader providing safe and reliable utility services

OUR VISION

Improving communities through curiosity and innovation

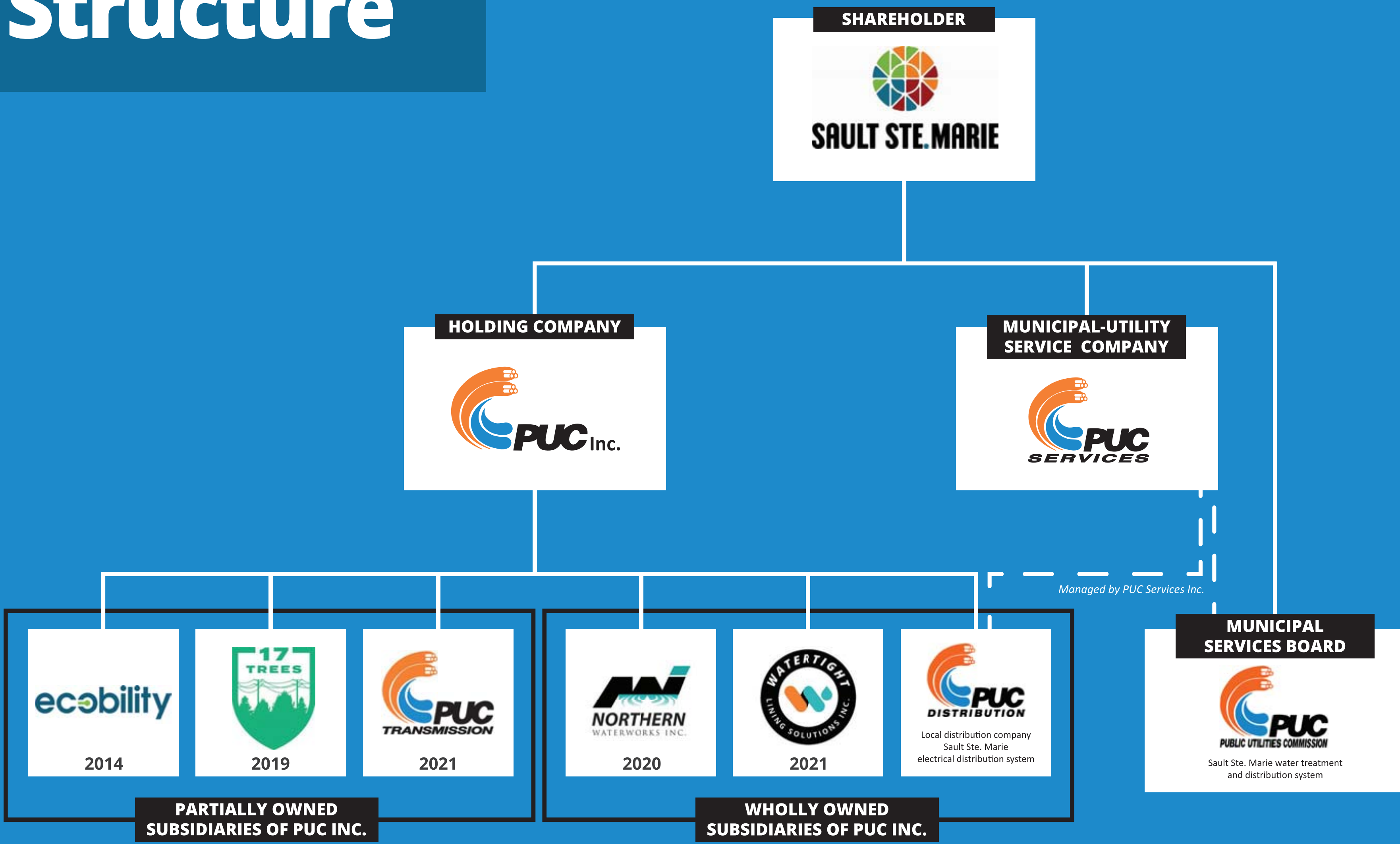
OUR VALUES

Safety, Integrity, Customer Centric, Innovative, Accountable

AREAS OF STRATEGIC FOCUS

Customers — Employees — Shareholder

Corporate Structure



Where We Operate

Sachigo Lake
Big Trout Lake
Wawakapewin
Muskrat Dam
Sandy Lake
North Caribou Lake
Missinabie (N)
Poplar Hill
Pikangikum
Mishkeegogamang
Balmertown
Cochenour
Red Lake
Madsen
Ear Falls
Hudson
Sioux Lookout
Ignace
Big Grassy
Atikokan

Marathon
Pic Mobert
Missinabie (E)

Sault Ste. Marie
Espanola
Goulais River
Richards Landing
Desbarats
Iron Bridge
Thessalon
Algoma Mills
Pronto
Serpent River
Blind River

Attawapiskat
Kashechewan
Fort Albany

LEGEND

Water
Wastewater
Electricity

Advancement

Growing with Purpose

PUC's focus on sustainability has been an effective way to increase innovation capability and enable significant growth. By weighing all decisions through this lens, PUC has identified, pursued, and launched several new opportunities that are rooted in community partnerships and innovative ideas.

PUC Transmission LP

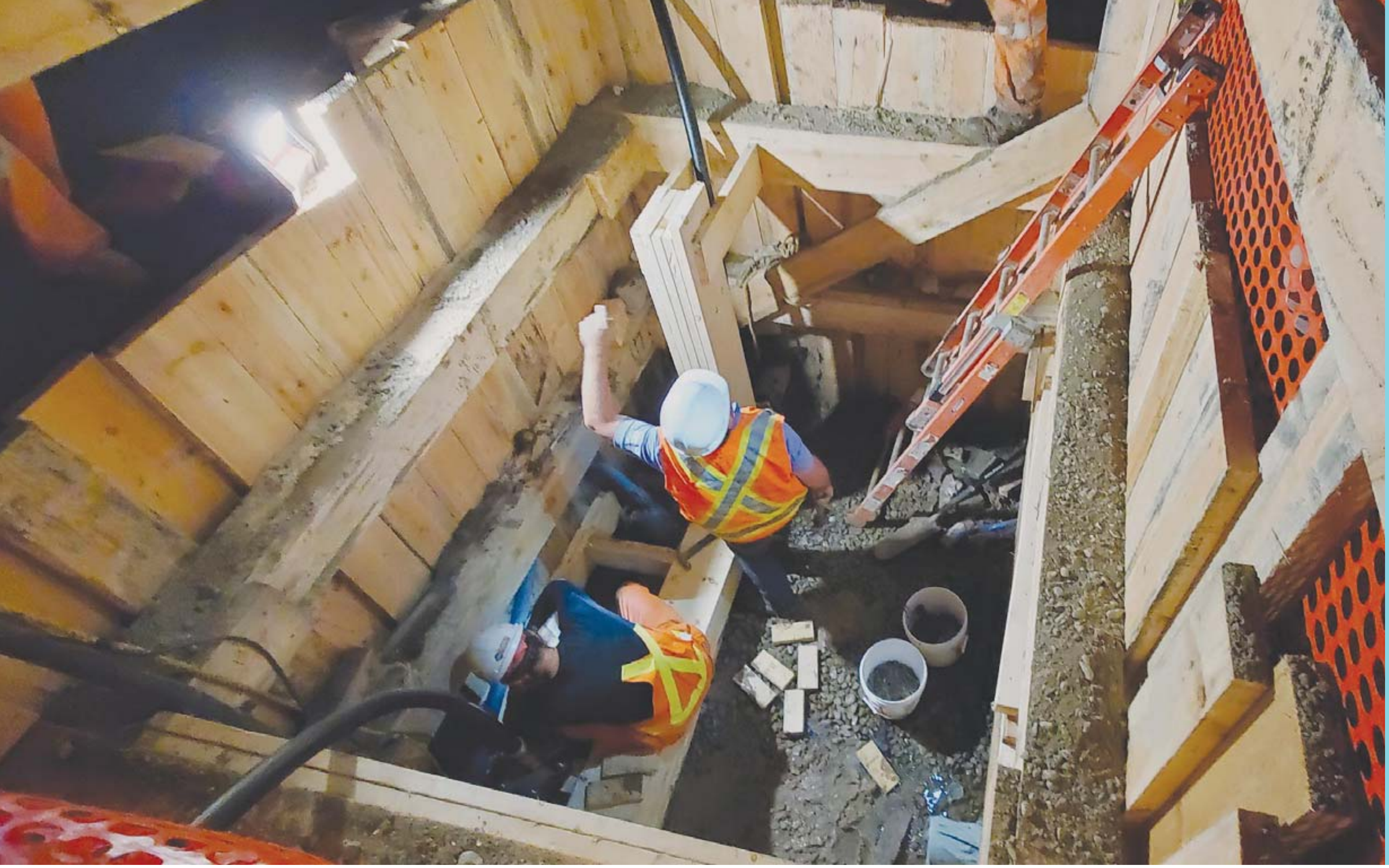
PUC Transmission LP is a newly formed Ontario transmission company owned by PUC Inc. The company, which was approved for a transmission licence by the OEB in October 2021, represents an investment of $100 million by PUC to construct new transmission facilities in Sault Ste. Marie.

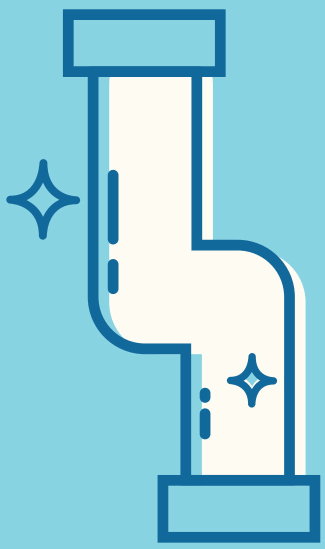
The new transmission facilities will provide power to Algoma Steel Inc's new electric-arc furnaces. The new dual furnaces are expected to reduce carbon emissions by approximately 70%, positioning Algoma for long-term growth in the expanding market for green steel.

In the spring and summer of 2022, the project will undergo a stringent Environmental Assessment (EA) and public consultation process. Construction of the facilities is anticipated to start by September 2023, with completion anticipated by December 2024.

PUC Transmission LP will have a profound impact on Sault Ste. Marie, dramatically impacting the environment and quality of air in the region. It also brings significant benefits to PUC that will contribute to the financial sustainability of the company for years to come. For more information, visit puctransmissionlp.com

PUC TRANSMISSION LP





490

METERS OF PIPE RESTORED IN 2021

Watertight Lining Solutions Inc.

In the fall of 2021, PUC incorporated its newest business venture, Watertight Lining Solutions Inc. (WLS). The new company focuses on helping municipalities fix an expensive and common problem: deteriorating water pipe.

WLS uses a Spray-in-Place-Pipe (SIPP) process which uses a polymer lining (Resiline 320). This process can save taxpayers millions of dollars, limit construction delays to as little as one day, and reduce the carbon footprint by up to 75% compared to typical replacement pipe.

In Sault Ste. Marie, WLS restored close to 450 meters of pipe in 2021. As the only authorized applicator of Resiline 320 in Ontario, WLS stands to grow significantly over the next few years, leaving a wake of positive impacts on both the environment and customers.

WATERTIGHT LINING SOLUTIONS INC.

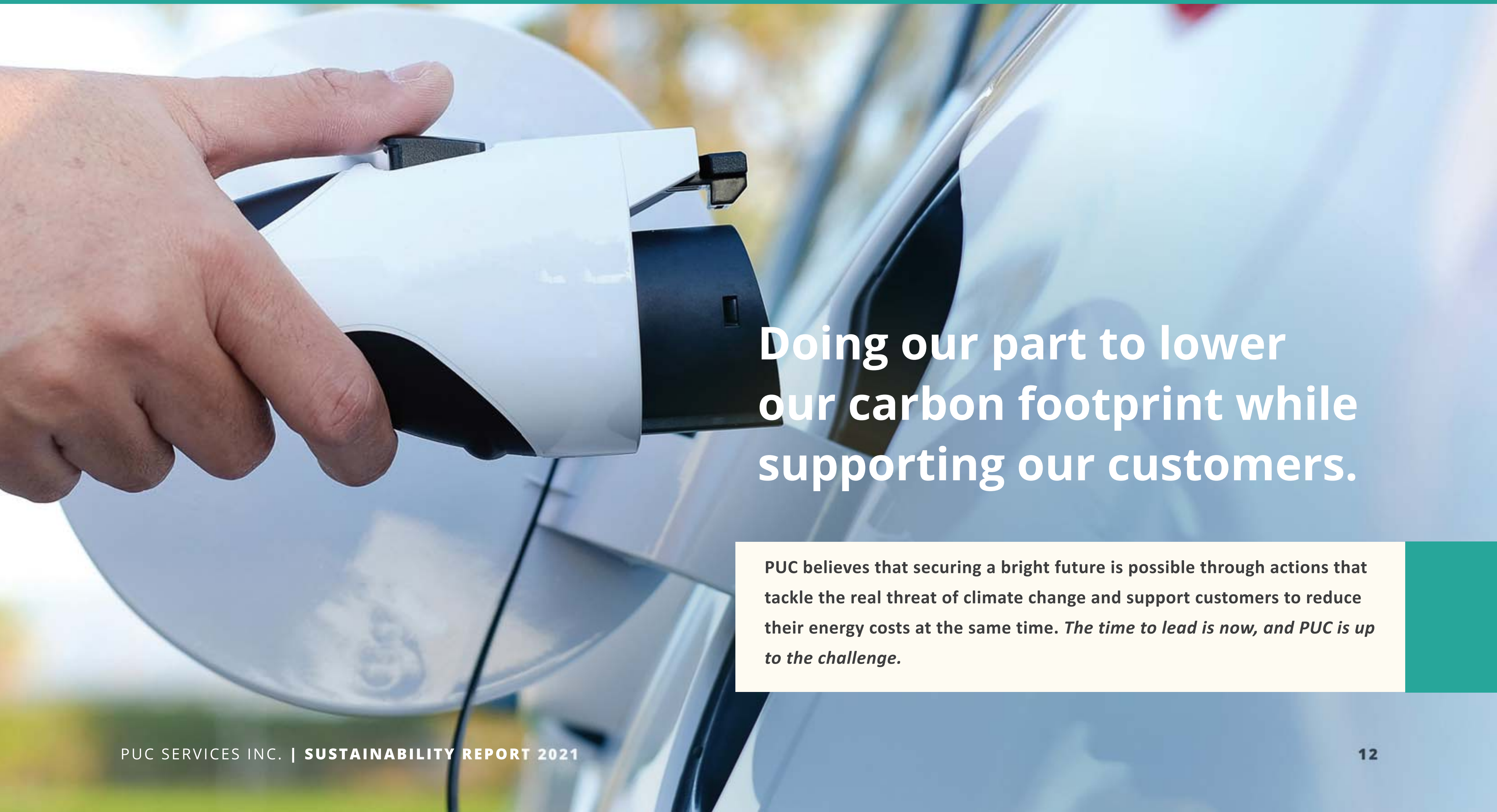
Northern Waterworks Inc.

Northern Waterworks Inc. (NWI) is a wholly owned subsidiary of PUC Inc. that has been providing water and wastewater operations, maintenance and management services to Municipal, First Nation and Industrial clients for over two decades. NWI currently operates, maintains and manages 35 municipal water and wastewater sub-systems

2021 was a transitional year for NWI from a leadership point of view. Jason LeBlanc, one of the founding family members of NWI, retired after a long and successful career. NWI would like to recognize and thank Jason for his years of commitment and dedication. This transition saw the onboarding of two new executives, Jim McLean and Andrew Hallett.

Facing another difficult year due to the ongoing COVID-19 pandemic, the company still met its yearly revenue goal.

Responsibility



Doing our part to lower our carbon footprint while supporting our customers.

PUC believes that securing a bright future is possible through actions that tackle the real threat of climate change and support customers to reduce their energy costs at the same time. *The time to lead is now, and PUC is up to the challenge.*

Sault Smart Grid

The first of its kind in Canada, PUC's Sault Smart Grid will transform the way PUC delivers electricity. Estimates show it will result in average customer energy savings of 2.7 per cent, improve reliability and contribute to a direct reduction of greenhouse gas (GHG) emissions equivalent to 2,804 tonnes of carbon dioxide annually.

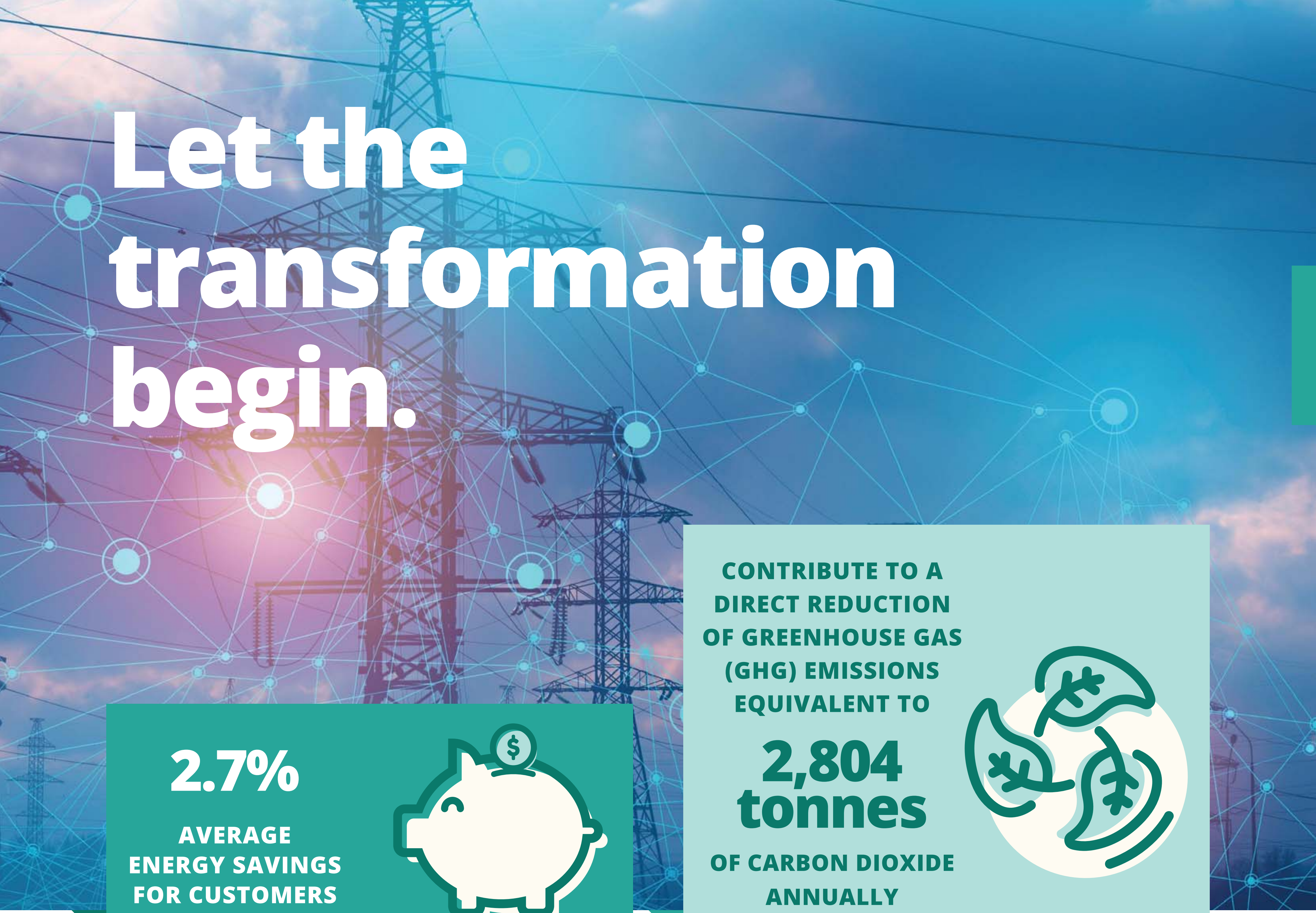
The project officially received the green light in early 2021, when the Ontario Energy Board (OEB) and the shareholder (City of Sault Ste. Marie) formally approved the project.

Through the balance of 2021, engineers and the design team worked to confirm the scope of work and develop specifications for long-lead equipment. Purchase orders were issued to secure delivery of critical equipment needed starting in the spring of 2022, when smart grid construction will begin.

With expectations that we'll see more demand for electric vehicle hookups, rooftop solar energy and other new technology in the next decade, the PUC smart grid system will help the city modernize and leap forward in meeting those challenges and opportunities. PUC is excited about this project bringing customers an energy system that is more efficient, reliable, resilient, and responsive.

The 33-million-dollar project is on schedule to be completed by the first quarter of 2023.

SAULT SMART GRID



Let the transformation begin.

2.7%

AVERAGE ENERGY SAVINGS FOR CUSTOMERS

CONTRIBUTE TO A DIRECT REDUCTION OF GREENHOUSE GAS (GHG) EMISSIONS EQUIVALENT TO

2,804 tonnes

OF CARBON DIOXIDE ANNUALLY

track and monitor energy consumption to save

MyPUC Mobile App

PUC is continually looking for ways to create positive experiences for customers, while at the same time encouraging behaviour that is more responsive to energy conservation.

Through public engagement, customers indicated they wanted a mobile communications solution that made it easier to manage their usage and accounts and receive up-to-date information on power and/or water disruptions.

PUC listened, and in 2021 partnered with Screaming Power to develop and market a mobile app that would do all of the above and more; facilitate better two-way communication with customers, provide better and faster updates on outages, and help customers better manage their usage, ultimately saving them money.

Since it's launch in July 2021, thousands of PUC customers are using the MyPUC App, conserving more energy and enjoying a better overall experience with their community utility.

MYPUC MOBILE APP

Customer Energy Management (CEMa)

The Customer Energy Management program (CEMa) will provide meaningful reductions in GHG emissions for organizations and businesses in Sault Ste. Marie.

For example, CEMa will help the Sault Area Hospital (SAH) to save an estimated 3 million dollars on its energy bill over the next ten years. The program will provide them with improved power reliability and quality while reducing energy bills through the use of a battery energy storage system. This will allow SAH to store electricity during off peak hours and use it during peak rate times, which are the busiest part of the day for the hospital.

Sault Area Hospital (SAH) will save an estimated 3 million dollars on its energy bill over the next ten years.

SAULT AREA HOSPITAL (SAH) WILL SAVE AN ESTIMATED

$3M

ON ITS ENERGY BILL OVER THE NEXT 10 YEARS

AffordAbility Fund Trust

The AffordAbility Fund Trust (AFT) program officially wrapped up in 2021. Throughout the duration of the program commencing in 2017, PUC Services delivered the program to 6,811 customers in the City of Sault Ste. Marie and Espanola. 2,830 customers received appliances (on average 2 per home), and 683 heat pumps were installed. Not only did the program support customers, but it also brought in over 10 million dollars to the local economy.

Customer feedback was very positive from participants, with many communicating that they were grateful for the appliances and heat pumps, but also the way in which the program was delivered.

Electrifying our fleet

PUC IS INSTALLING
22
ELECTRIC VEHICLE CHARGING STATIONS

Electric Vehicle (EV) Strategy

You cannot speak about sustainability without having a strategy for electric vehicles. According to the Government of Canada, at least 20 per cent of all passenger vehicles sold in Canada will be zero-emission vehicles (ZEVs) by 2026, and at least 60 per cent by 2030, and 100 per cent by 2035.

In 2021, PUC put in place a plan for the gradual incorporation of electric vehicles to replace the current fleet of internal combustion engine (ICE) vehicles. PUC will be taking a phased-in approach for the transition from traditional to electric vehicles, meaning that the electric vehicles will substitute the ICE vehicles when they need replacement.

To coincide with the transition into electric vehicles, PUC is also planning on installing 22 electric vehicle charging stations at PUC faciliites to accommodate the newly transitioned vehicles. This change of going electric will not only contribute further to the company's goal of reducing its own carbon footprint, but it will lead to an even bigger impact on the community overall.

In 2022, PUC plans to roll out a program that installs and maintains charging stations for residential customers at their homes.

Capital Infrastructure Investments

By investing in aging infrastructure, PUC is investing directly into the sustainability of the communities we serve. New infrastructure improves reliability, reduces maintenance costs, and adds additional capacity to a growing community.

In 2021, PUC invested more in electrical and water infrastructure than ever have before.

Let's take a look at some of the significant projects brought to life this year.

Substation 16 Rebuild

This multi-year project to renew one of PUC Distribution's fourteen electrical distribution stations reached substantial completion at the close of 2021. The new design, located in the north end of the city, encloses all equipment in a building to suit the surrounding neighbourhood with public safety in mind. It features state-of-the-art protection systems, gas insulated switchgear and oil containment for transformation. This important update brings needed additional capacity to this growing area, improves reliability to connected customers, reduces routine maintenance requirements and provides enhanced safety conditions for PUC employees.

IN 2021

one 4kV substation

AND ASSOCIATED KILOMETRES OF LINES WERE ELIMINATED.

Voltage Conversion Program

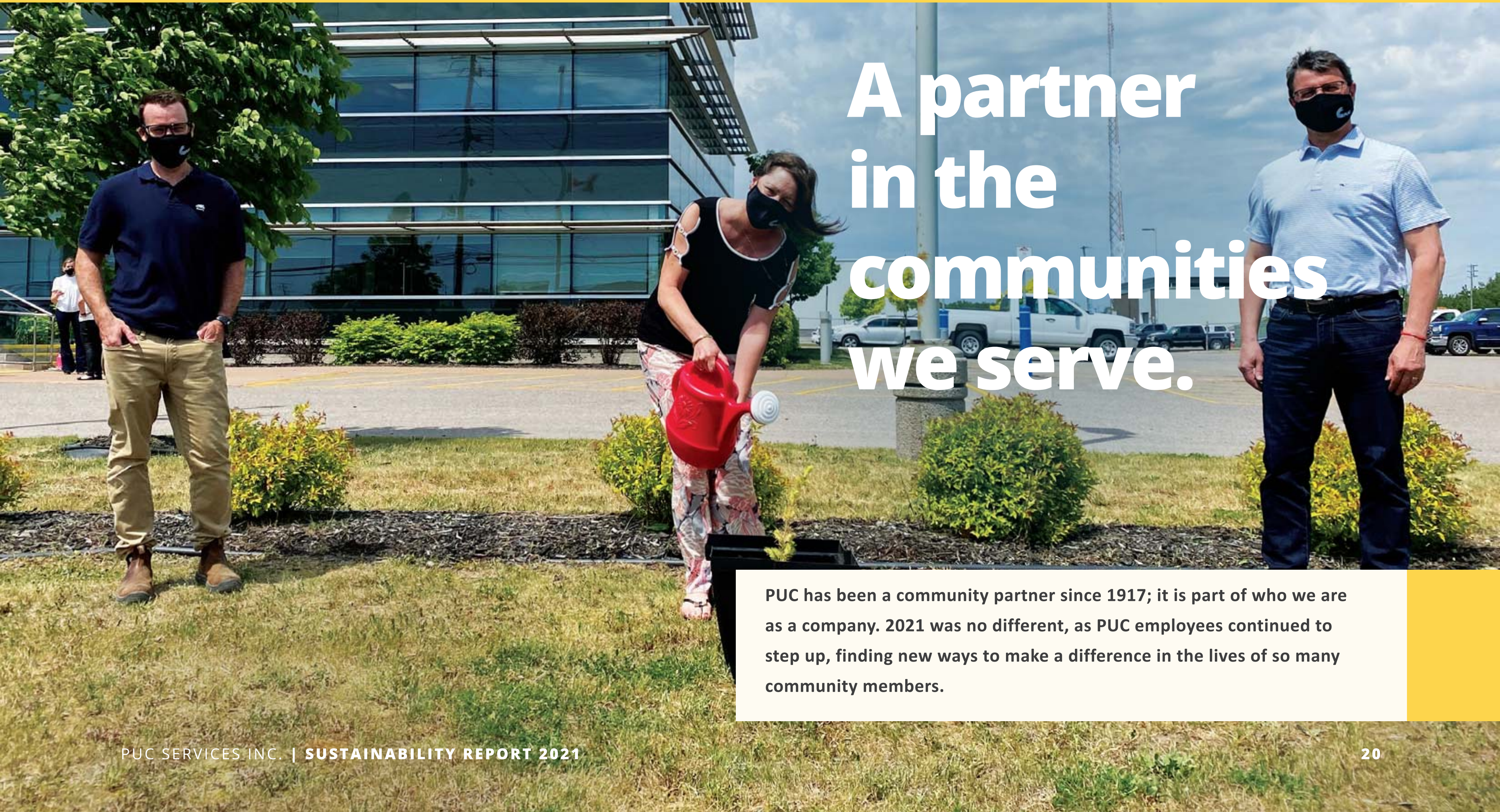
As the PUC electrical distribution system grew over the latter half of the last century to serve the Sault Ste. Marie area, distribution assets were acquired at two voltage levels, 4kV and 12kV. In an effort to reduce system losses, complexity and costs while improving reliability and safety, a commitment was made to eliminate the 4kV assets as they reached end of life and replace them with 12kV. Considerable focus has been placed on bringing this initiative to a conclusion over the past decade and the last few kilometers of conductor and remaining two stations are expected to be retired by 2024. In 2021, we saw the retirement and site remediation of one 4kV substation and associated lines were eliminated.

In 2021, we saw the retirement and site remediation of one 4kV substation and associated kilometres of lines were eliminated.

Zone Two Booster Pump Upgrades

The Zone 2 Booster Station, located just outside the PUC Office building at 500 Second Line, is a critical component in the Sault Ste. Marie water distribution system. A multi-year booster pump upgrade project was embarked upon in 2020 and substantially completed by the end of 2021. The goals of the upgrade are to renew the end-of-life infrastructure, improve performance and provide enhanced worker safety at the facility. The project involves the replacement of four main pumps, associated valves and all associated electrical and motor control systems. The emergency generator supplying this mission critical facility was also replaced.

Engagement



A partner in the communities we serve.

PUC has been a community partner since 1917; it is part of who we are as a company. 2021 was no different, as PUC employees continued to step up, finding new ways to make a difference in the lives of so many community members.

Tree Giveaway

In May 2021, PUC gave away 2500 spruce tree seedlings to the community. The trees were a symbol of renewal and growth. As the trees grow, they will represent just how far we have come since the COVID-19 pandemic first changed our day-to-day lives. PUC also used the tree giveaway to remind people about the importance of powerline safety. Thirty per cent of power outages in Ontario are caused by trees coming in contact with power lines.

PUC GAVE
2500
SPRUCE TREE SEEDLINGS TO THE COMMUNITY

Halloween Safety

Leading up to Halloween, PUC crews inspected the streetlight system throughout the entire city to ensure all trick or treaters could safely see where they were walking. This is an annual campaign that our employees are proud to take part in.

HALLOWEEN SAFETY

Powerline Safety Message

We have recently seen a rise in safety incidents where members of the public are coming in close proximity to our powerlines. As a result, PUC created a powerline safety video educating the public on how dangerous powerlines are.

POWERLINE SAFETY MESSAGE

Donations and Sponsorship

In 2021, PUC donated to nearly two dozen different charities and events in Sault Ste. Marie. PUC took a leadership role in supporting the Algoma Vaccination Support Council (AVSC) and its cause of promoting and supporting vaccine clinics. PUC created a new program that saw the company organize and pay for taxi rides for anyone who needed transportation to their vaccine appointment. More than 100 families utilized this program. The company also supported the fantastic volunteers who ran the numerous vaccine clinics in our region by paying for their lunches and dinners.

DONATIONS 2021

ALGOMA VACCINATION SUPPORT COUNCIL

18
CHARITIES SUPPORTED

Resiliency

Our focus on the health and safety of our employees

PUC's employees are knowledgeable, innovative, customer-centric, and above all else, laser focused on safety. This focus in reflected in PUC's impressive safety results year over year. It goes beyond just statistics, however. PUC has cultivated a culture of safety that is second to none in the utility industry.

Protecting our employees during COVID-19 pandemic

As the COVID-19 pandemic rolled on in 2021, PUC made it a priority to ensure all employees were confident that their workplace was a safe environment to be in. As a team, PUC continued to navigate these rapidly changing times through cooperation and teamwork. As measures external to the organization changed, PUC was able to pivot, remain flexible and adapt to maintain a safe workplace.

PUC ACHIEVED

2500

PERSON-HOURS WITHOUT A LOST-TIME INJURY

Health and Safety Record

When you look at our wall of values, safety is the first value written. Safety is not just another word in our PUC vocabulary, it is the most important word for us each day.

In 2021, we hit two significant milestones. In May, PUC achieved 1,000,000 person-hours without a lost-time injury. PUC employees recorded 1000 straight days without a lost-time injury in the fall. These achievements highlight our employees' dedication to making sure everyone continues to look out for each other and work safely in everything they do.

HEALTH AND SAFETY RECORD

Securing the Future

Financial Statements

PUC INC.

Non-Consolidated Statement of Financial Position

As at December 31, 2021, with comparative information for 2020

		2021		2020
Assets				
Current assets:				
Accounts receivable	$	711,951	$	942,415
Receivable from PUC Services Inc. (note 9)		2,834,151		2,520,244
Payment in lieu of taxes recoverable		10,098		16,764
Total current assets		3,556,200		3,479,423
Non-current assets:				
Deferred tax asset (note 8)		9,000		-
Notes receivable from related company (note 4)		8,310,000		8,310,000
Investments in subsidiaries and associates (note 5)		50,801,579		50,801,477
Total non-current assets		59,120,579		59,111,477
Total Assets	$	62,676,779	$	62,590,900
Liabilities and Shareholder's Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$	611,268	$	610,084
Long-term debt (note 6)		31,720,000		31,720,000
Total liabilities		32,331,268		32,330,084
Shareholder's equity:				
Share capital:				
Authorized:				
Unlimited Special shares, non-voting, non-cumulative, redeemable at $10,000 per share				
100,000 Common shares				
Issued and outstanding:				
1,462 Special shares		14,620,000		14,620,000
21,632 Common shares		14,618,248		14,618,248
Retained earnings		1,107,263		1,022,568
		30,345,511		30,260,816
Commitments (note 7)				
Total Liabilities and Shareholder's Equity	$	62,676,779	$	62,590,900

PUC INC.

Non-Consolidated Statement Comprehensive Income

Year ended December 31, 2021, with comparative information for 2020

		2021		2020
Revenue:				
Interest	$	2,257,019	$	2,255,698
Dividend income		710,080		940,164
		2,967,099		3,195,862
Expenses:				
Interest on long-term debt		1,934,920		1,934,920
Administrative		80,887		100,329
Business development		270,854		227,773
		2,286,661		2,263,022
Income before payment in lieu of taxes		680,438		932,840
Payment in lieu of taxes (recovery) (note 8)				
Current		(5,337)		(1,576)
Deferred		(9,000)		-
		(14,337)		(1,576)
Net income, being total comprehensive income for the year	$	694,775	$	934,416

Management has extracted this financial information from the audited financial statements.

PUC SERVICES INC.

Statement of Financial Position

As at December 31, 2021, with comparative information for 2020

		2021		2020
Assets				
Current assets:				
Cash	$	4,936,680	$	2,557,793
Accounts receivable (note 5)		3,153,508		5,299,586
Due from related parties (note 19)		13,753,188		11,183,645
Inventories (note 6)		461,524		384,678
Prepaid expenses		840,624		93,264
Payment in lieu of taxes recoverable		418,118		176,778
Total current assets		23,563,642		19,695,744
Non-current assets:				
Deferred tax assets (note 9)		-		278,000
Property, plant and equipment (note 7)		17,141,883		17,571,082
Intangible assets (note 8)		1,096,834		803,326
Total non-current assets		18,238,717		18,652,408
Total assets	$	41,802,359	$	38,348,152
Liabilities and Shareholder's Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$	4,649,365	$	4,371,871
Deferred tax liabilities (note 9)		22,000		-
Dividends payable		225,000		-
Due to related parties (note 19)		10,806,857		7,942,155
Current portion of long-term debt (note 10)		85,656		85,656
Lease liabilities - current		31,936		-
Total current liabilities		15,820,814		12,399,682
Non-current liabilities:				
Long-term debt (note 10)		8,972,218		9,057,874
Lease liabilities (note 11)		68,968		-
Deferred revenue (note 7)		10,578,508		10,820,871
Employee future benefit obligations (note 12)		1,786,769		2,349,497
Total non-current liabilities		21,406,463		22,228,242
Total liabilities		37,227,277		34,627,924
Shareholder's equity:				
Share capital (note 15)		1,943,300		1,943,300
Accumulated other comprehensive income		654,773		162,758
Retained earnings		1,977,009		1,614,170
Total shareholder's equity		4,575,082		3,720,228
Commitments and contingencies (note 18)				
Total liabilities and shareholder's equity	$	41,802,359	$	38,348,152

PUC SERVICES INC.

Statement of Income and Comprehensive Income

Year ended December 31, 2021, with comparative information for 2020

		2021		2020
Revenue:				
Management fees	$	10,709,906	$	11,292,230
Contracts		5,840,561		5,890,479
Services		4,199,340		4,827,155
Other operating revenue (note 16)		1,553,440		1,459,062
		22,303,247		23,468,926
Expenses:				
Contract service		8,371,701		8,737,137
Administrative		5,331,641		6,251,737
Facilities		2,065,206		2,060,376
Depreciation and amortization		2,448,494		2,183,329
Billing and collection		1,211,302		1,053,990
Customer service		1,044,460		931,276
Street lights		403,001		391,759
New business development		270,902		227,773
Other business and maintenance		68,915		69,523
		21,215,622		21,906,900
Income from operating activities		1,087,625		1,562,026
Net finance costs (note 17)		489,130		502,784
Income before provision for payment in lieu of taxes		598,495		1,059,242
Payment in lieu of taxes (note 9):				
Current (recovery) expense		(111,951)		129,389
Deferred expense		122,607		183,824
		10,656		313,213
Income for the year		587,839		746,029
Other comprehensive income (loss): items that will not be classified to profit or loss, net of income tax:				
Remeasurement of employee future benefits (note 12)		669,408		(120,091)
Income tax recovery (expense) on other comprehensive income (note 9)		(177,393)		31,824
Other comprehensive income (loss) for the year		492,015		(88,267)
Net income and comprehensive income for the year	$	1,079,854	$	657,762

Management has extracted this financial information from the audited financial statements.

PUC DISTRIBUTION INC.

Statement of Financial Position

December 31, 2021, with comparative information for 2020

		2021		2020
Assets				
Current assets:				
Cash	$	815,229	$	124,037
Accounts receivable (note 4)		6,121,404		5,738,294
Unbilled revenue		10,976,609		12,240,212
Payment in lieu of taxes recoverable		9,709		8,991
Inventory (note 5)		2,161,802		2,020,118
Prepaid expenses		200,875		67,672
Total current assets		20,285,628		20,199,324
Non-current assets:				
Property, plant and equipment (note 6)		112,462,126		105,376,966
Total assets		132,747,754		125,576,290
Regulatory balances (note 8)		9,437,146		4,570,573
Total assets and regulatory balances	$	142,184,900	$	130,146,863

PUC DISTRIBUTION INC.

Statement of Financial Position (continued)

December 31, 2021, with comparative information for 2020

		2021		2020
Liabilities and Shareholder's Equity				
Current liabilities:				
Accounts payable and accrued liabilities	$	12,141,711	$	8,419,954
Customer deposits (note 11)		313,596		712,937
Dividends payable		610,080		610,080
Due to related parties (note 17)		12,638,877		10,688,540
Current portion of long-term debt (note 10)		1,923,586		1,727,219
Total current liabilities		27,627,850		22,158,730
Non-current liabilities:				
Deferred revenue (note 9)		7,034,528		4,829,126
Deferred tax liability		1,989,000		1,387,000
Long-term debt (note 10)		66,156,179		64,079,966
Total non-current liabilities		75,179,707		70,296,092
Total liabilities		102,807,557		92,454,822
Shareholder's equity:				
Share capital (note 12)		20,062,107		20,062,107
Retained earnings		18,618,415		16,811,240
Total shareholder's equity		38,680,522		36,873,347
Total liabilities and shareholder's equity		141,488,079		129,328,169
Regulatory balances (note 8)		696,821		818,694
Commitments and contingencies (note 16)				
Total liabilities, regulatory balances and shareholder's equity	$	142,184,900	$	130,146,863

Management has extracted this financial information from the audited financial statements.

PUC DISTRIBUTION INC.

Statement of Income and Comprehensive Income

Year ended December 31, 2021, with comparative information for 2020

	2021	2020
Revenue:		
Electricity sales (note 13)	$ 71,763,066	$ 85,083,387
Distribution revenue (note 13)	19,207,805	19,032,237
	90,970,871	104,115,624
Other operating revenue (note 14)	7,281,109	7,630,820
	98,251,980	111,746,444
Expenses:		
Energy purchases	71,603,747	85,555,982
Operations and maintenance	6,406,837	6,434,364
General and administrative	4,025,734	3,129,473
Billing and collection	1,370,374	1,333,216
Depreciation and amortization	3,842,226	4,153,218
Community relations	5,206,928	5,307,274
	92,455,846	105,913,527
Income from operating activities	5,796,134	5,832,917
Net finance costs (note 15)	3,023,221	3,187,222
Income before tax and regulatory items	2,772,913	2,645,695
Income tax expense:		
Current (note 7)	71,089	76,523
Deferred (note 7)	602,000	677,000
	673,089	753,523
Income for the year before movements in regulatory deferral account balances	2,099,824	1,892,172
Net movement in regulatory deferral account balances related to income or loss	284,569	(188,490)
Income tax	(602,000)	(677,000)
	(317,431)	(865,490)
Net income, being total comprehensive income for the year	$ 2,417,255	$ 2,757,662

PUBLIC UTILITIES COMMISSION OF THE CITY OF SAULT STE. MARIE

Statement of Financial Position

December 31, 2021, with comparative information for 2020

	2021	2020
Financial assets:		
Cash	$ 115,178	$ 425,098
Accounts receivable	4,167,971	3,875,625
Unbilled service revenue	1,194,468	978,476
Receivable from related company, PUC Services Inc. (note 3)	7,972,706	5,421,911
	13,450,323	10,701,110
Financial liabilities:		
Accounts payable and accrued liabilities	5,427,054	4,130,854
Loan payable (note 5)	3,569,084	4,376,289
	8,996,138	8,507,143
Total net financial assets	4,454,185	2,193,967
Non-financial assets:		
Tangible capital assets (note 7)	102,761,366	97,236,873
Inventory	379,218	335,182
	103,140,584	97,572,055
Effects of COVID-19 (note 10)		
Accumulated surplus (note 8)	$ 107,594,769	$ 99,766,022

Management has extracted this financial information from the audited financial statements.

PUBLIC UTILITIES COMMISSION OF THE CITY OF SAULT STE. MARIE

Statement of Operations and Accumulated Surplus

Year ended December 31, 2021, with comparative information for 2020

		2021 Budget (note 2)		2021 Total		2020 Total
Revenues:						
Service revenue:						
Residential	$	12,634,909	$	13,044,603	$	12,659,411
General		8,625,510		8,074,650		7,876,008
Hydrants		1,524,778		1,565,902		1,533,823
		22,785,197		22,685,155		22,069,242
Other:						
Investment income		75,000		114,547		103,412
Non-service revenue		280,830		676,961		395,597
Developers contributions		-		1,091,918		93,421
		355,830		1,883,426		592,430
Total revenues		23,141,027		24,568,581		22,661,672
Expenditures: (note 6)						
Purification and pumping		4,135,119		3,749,726		3,603,667
Transmission and distribution		4,532,982		4,157,152		3,645,013
Amortization of tangible capital assets		2,754,935		2,788,336		2,640,705
Hydrants		660,129		409,965		514,253
Billing and collection		1,233,381		1,348,595		1,134,564
Interest on long-term debt		124,661		124,715		149,402
General and administration		4,137,494		4,161,345		4,475,593
Total expenditures		17,578,701		16,739,834		16,163,197
Operating surplus		5,562,326		7,828,747		6,498,475
Accumulated operating surplus, beginning of year		99,766,022		99,766,022		93,267,547
Accumulated operating surplus, end of year	$	105,328,348	$	107,594,769	$	99,766,022

Management has extracted this financial information from the audited financial statements.

Thank You

Thank you to the communities we serve for putting your trust in us every single day. We will continue to be your partner in finding new ways to make a brighter tomorrow possible.

Executive Team

Robert Brewer,
Hon. BSC, MBA

PRESIDENT & CEO

Kevin Bell,
P.Eng.

VICE PRESIDENT, SPECIAL PROJECTS

Claudio Stefano,
P.Eng, MBA

**EXECUTIVE LEAD,
OPERATIONS & ENGINEERING**

Guillaume Vachon,
P.Eng., PMP

**VICE PRESIDENT,
ELECTRIC OPERATIONS & ENGINEERING**

Kelly McLellan,
CPA, CMA, M.Acc

CHIEF FINANCIAL OFFICER

Robert Battisti,
CPA, CMA, MBA

VICE PRESIDENT, CORPORATE SERVICES

BOARD OF DIRECTORS PUCSERVICES INC./PUC INC.

Jim P. Boniferro
CHAIR, PRESIDENT & CEO, BONIFERRO MILL WORKS ULC

Andy McPhee
VICE-CHAIR, RETIRED VICE-PRESIDENT, GREAT LAKES POWER TRANSMISSION

Christian Provenzano
MAYOR, CITY OF SAULT STE. MARIE

Elaine Pitcher
LAWYER, PITCHER LAW

Carla Fabbro
DIRECTOR, PORTFOLIO MANAGEMENT, OLG

Neil Strom
MILL CONTROLLER, ALGOMA STEEL INC.

Ila Watson
PRESIDENT & CEO, SAULT AREA HOSPITAL

Cecilia Bruno
RETIRED, CHIEF FINANCIAL OFFICER, SAULT COLLEGE

PUC DISTRIBUTION INC.

Jim Rennie
CHAIR VICE-PRESIDENT, HUMAN RESOURCES, IRVING SHIP BUILDING

Pat McAuley
RETIRED, COMMISSIONER OF PUBLIC WORKS AND TRANSPORTATION FOR THE CITY OF SAULT STE. MARIE

Jim P. Boniferro
PRESIDENT & CEO, BONIFERRO MILL WORKS ULC

Christian Provenzano
MAYOR, CITY OF SAULT STE. MARIE

Mark Howson
RETIRED, SENIOR MAINTENANCE ENGINEER, ESSAR STEEL ALGOMA INC.

PUBLIC UTILITIES COMMISSION

Mark Howson
CHAIR, RETIRED, SENIOR MAINTENANCE ENGINEER, ESSAR STEEL ALGOMA INC.

Christian Provenzano
MAYOR, CITY OF SAULT STE. MARIE

Sandra Hollingsworth
CITY COUNCILLOR, CITY OF SAULT STE. MARIE

David Zuccato
RETIRED, SENIOR PROVINCIAL CIVIL SERVANT

Dr. Musa Onyuna
METALLURGICAL SPECIALIST, ALGOMA STEEL INC.

APPENDIX J

Map of

Distribution

Service Territory

and Service Areas

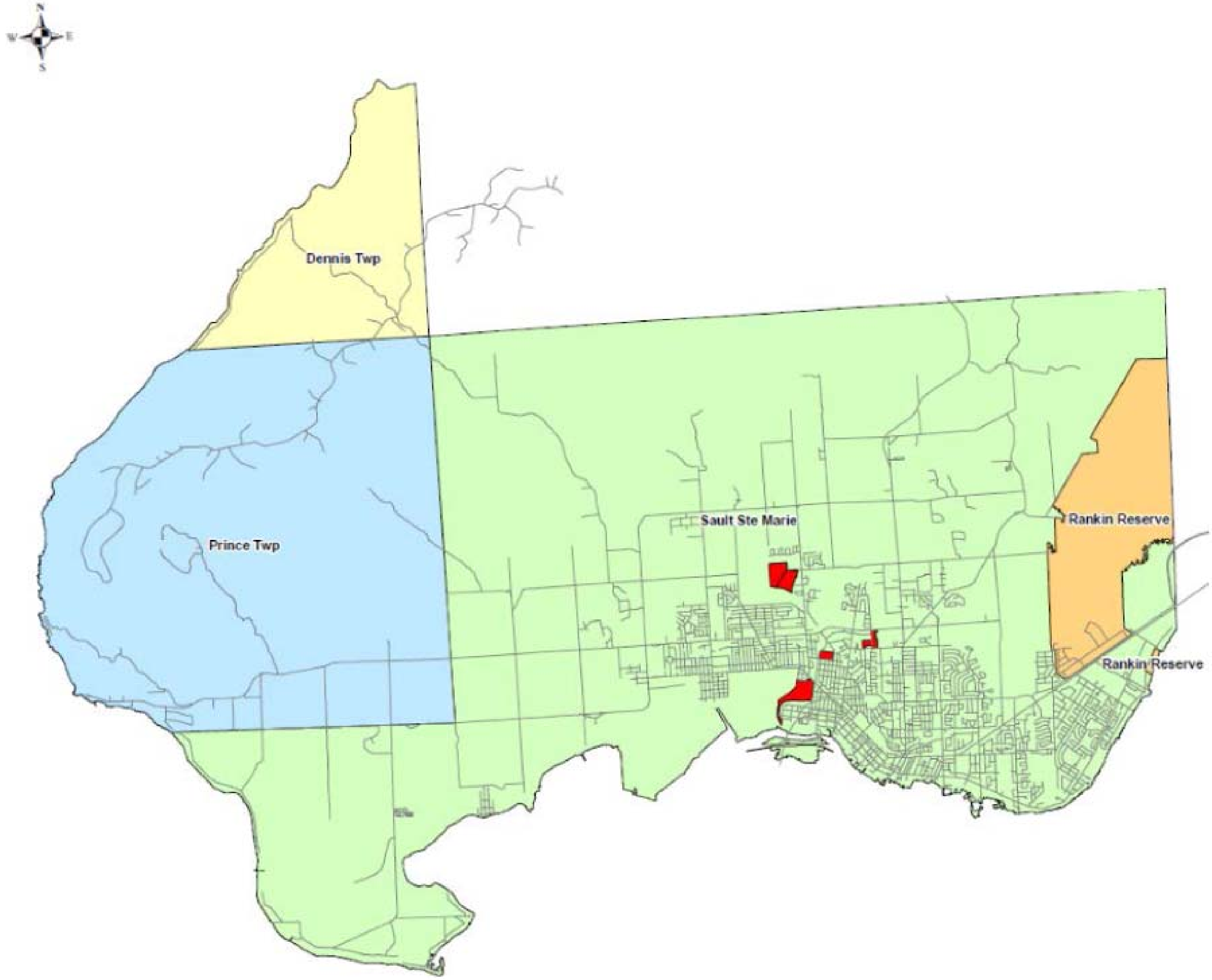


Figure 10: PUC Distribution Service Territory

APPENDIX K

App. 2-AC Customer Engagement Activities Summary

File Number: EB-2022-0059
Exhibit:
Tab:
Schedule:
Page:

Date: August 31, 2022

Appendix 2-AC
Customer Engagement Activities Summary

Provide a list of customer engagement activities	Provide a list of customer needs and preferences identified through each engagement activity	Actions taken to respond to identified needs and preferences. If no action was taken, explain why.
Customer Engagement Online Survey (in-house) 2021	Based on the results of this survey, it was noted that PUC should explore more options for customer communications and energy savings tools and invest in maintaining reliable electricity services.	Based on this feedback, PUC has madeis making significant investments through the Sault Smart Grid project that will result in upgrades to equipment, a reduction in the response times to outages, a reduction in the number of outages and a reduction PUC's environmental impact through more efficient energy consumption. In addition, PUC has purchased electric vehicles and developed a plan further electrify their fleet to lower maintenance and fuel costs and lower their carbon footprint. Improved communications through pro-active measures like the MyPUC App, website tools and more consistent use of social media platforms, PUC has been able to get in front of issues (including outaqges) for a better overall customer experience. Customers can now access information on planned outages, news updates, changes in electricity rates, etc. on multiple platforms, thereby improving a customer's overall experience with PUC.
Customer Engagement Online Survey (in-house) 2022	Based on the results of this survey, it was noted that PUC should focus its priorities on delivering reasonably priced electricity prices and ensuring safe and reliable electricity prices, provide a variety of options for customers when accessing services with a focus on online tools, and provide reliable information and services regarding the adoption of electric vehicles.	PUC has launched a 'mythbusters' campaign via web, digital advertising, social media, and outreach events, such as 'Rotarty Fest', regarding electric vehicles, in order to provide reliable information on the adoption of electric vehicles.
Bi-annual Customer Satisfaction Survey (UtilityPULSE) 2019	From this survey, customers expressed that the following should be priorities for PUC: •Pro-actively maintaining and upgrading equipment •Reducing response times to outages •Investing in projects to reduce the environmental impact of the utility's operations •Investing more in the electricity grid to reduce outages	Based on this feedback, PUC has made significant investments through the Sault Smart Grid project that will result in upgrades to equipment, a reduction in the response times to outages, a reduction in the number of outages and a reduction PUC's environmental impact through more efficient energy consumption. In addition, PUC has purchased electric vehicles and developed a plan further electrify their fleet to lower maintenance and fuel costs and lower their carbon footprint.
Bi-annual Customer Satisfaction Survey (UtilityPULSE) 2021	From this survey, customers expressed that the following should be priorities for PUC: •Movement to more digitization •Improvements to communication (more pro-active approaches) •Better prices and lower rates •Simplified billing •Enhance cyber security measures	Based on this feedback, PUC has put in place a digitization strategy, with a goal of going paperless by 2024. Since the initiative was launched in 2019, PUC has reduced day to day printing dramatically, increased on-line payments to vendors, enhanced the customer experience by providing flexibility, and restructured processes internally for employees to promote efficiencies. Some specific examples include the promotion of e-billing for customers, the development of the MyPUC App, the elimination of printed paystubs, an increase in Electronic Fund Transfers from 8% to over 40%, and the development of an online employee portal, Dayforce. PUC has improved pro-active communications through the development of the MyPUC App, and the increased use of social media platforms and PUC's website. For example, in addition to ATLAS phone notifications, the MyPUC app and website now display information on planned power outages in advance, so that customers can properly prepare for the interruption. PUC recognizes the threat that cyber security represents, and is taking measures to mitigate that risk. PUC has made significant investments in our cyber security infrastructure, including the addition of personnel. In order to simplify billing, PUC has continued to encourage customers to sign up for preauthorized payments, e-billing and the MyPUC App. Lastly, PUC has made significant investments through the Sault Smart Grid project that will result in average residential customer savings of 2.5%.
(4) Customer Pulse Surveys (in-house) March, July, November, December 2020	Based on the results of those surveys, it was noted that PUC should look at ways to create energy savings for customers, consider increasing bills, if it means improvements to reliability, efficiency and communications, make major investments in how PUC operates to reduce their carbon footprint, improve and enhance the customer experience, and look at ways to improve electrical reliability.	ased on this feedback, PUC has made is making significant investments through the Sault Smart Grid project that will result in upgrades to equipment, a reduction in the response times to outages, a reduction in the number of outages and a reduction PUC's environmental impact through more efficient energy consumption. In addition, PUC has purchased electric vehicles and developed a plan further electrify their fleet to lower maintenance and fuel costs and lower their carbon footprint. Through the increased use of social media platforms and website, and the development of the MyPUC App, PUC has made major efforts to be more pro-active with customer communications. PUC has improved pro-active communications through the development of the MyPUC App, and the increased use of social media platforms and PUC's website. For example, in addition to ATLAS phone notifications, the MyPUC app and website now display information on planned power outages in advance, so that customers can properly prepare for the interruption.
Public Awareness of Electrical Safety Survey (2018)	Ensuring the utility can provide safe electrical distribution, education and awareness about electrical safety, equipment and infrastructure, ensuring the utilities' operations are safe for workers and the public.	The Public Awareness of Electrical Safety Survey is conducted every two years. The purpose of the survey is to create awareness around electrical safety to customers.
Public Awareness of Electrical Safety Survey (2020)	Ensuring the utility can provide safe electrical distribution, education and awareness about electrical safety, equipment and infrastructure, ensuring the utilities' operations are safe for workers and the public.	The Public Awareness of Electrical Safety Survey is conducted every two years. The purpose of the survey is to create awareness around electrical safety to customers.
Public Awareness of Electrical Safety Survey (2022)	Ensuring the utility can provide safe electrical distribution, education and awareness about electrical safety, equipment and infrastructure, ensuring the utilities' operations are safe for workers and the public.	PUC promotes electrical safety via the PUC website, www.ssmpuc.com/safetytips, via digital advertising and social media. The ads provide tips for when customers are dealing with overhead wires (tree trimming), if you see a live wire, etc. The Public Awareness of Electrical Safety Survey is another opportunity to provide awareness of electrical safety.
Caution and Chance Electrical Safety Awareness Program	Providing a safe electrical service to the community, ensuring children are safe and aware of any electrical hazards.	The education and safety of the children in our community schools is very important to everyone at PUC. Since 1995, this interactive presentation has been offered annually to all local elementary schools. PUC coordinates and schedules the Caution and Chance Electrical Safety Program for Elementary Students in Grade 3 – 5. Students are provided with activity books and pencils following their presentation. Each year, the response from the teachers and students is very positive and they look forward to welcoming us back year after year.
Marketing Campaigns "Give Our Workers a Brake" and the "Call Before you Dig"	Providing a safe electrical service, ensuring that safety is our top priority with workers/community.	PUC creates opportunities to provide education to customers via marketing campaigns on tpics such as "Give Our Workers a Break" and "Call Before You Dig", that use digital and print advertising, social media and PUC's website, www.ssmpuc.com.
Digital Communication Tactics	PUC recognizes that as the utility industry evolves, so do their customers' needs and expectations. Today's customers have let us know that they are looking for fast, easy avenues through which they can gather information and manage their accounts, while conserving energy and saving money.	PUC is leveraging digital technology to facilitate and improve customer communications. The result has been improved integration through a variety of technologies (app, social media, etc.) into PUC's channel portfolio to improve customer communication and engagement, while at the same time reducing PUC's carbon footprint. PUC recognizes that companies who embrace digital communication also see higher levels of engagement from their customers; digital communication is a core element of a good customer experience strategy. Our Digital strategies, such as our Mobile App, Website, Video, Social Media and Digital Advertising, are easier to measure, adapt and optimize, and are often more cost efficient with a larger reach than
Traditional Communication Tactics	A segment of PUC's customer base want to receive information in traditional formats (ie. Call centre, mail)	PUC continues to provide customers with options that suit their lifestyle. While PUC aims to transition to digital and reduce their carbon footprint, the company understands that customers want choice and accommodates for individual needs and preferences.
Community Outreach	Community members want to see PUC out in the community.	It is important that PUC have a physical presence in the communities we serve. Connecting with community members is vital to PUC's communication and engagement strategy. Significant efforts have been made to get PUC employees out in the community on a more regular basis to interact with customers face-to-face and receive input. The COVID-19 pandemic had a negative impact on these efforts in 2020-2021, however, virtual events were held, as discussed under the section 'Town Halls & Open Houses'.
Emergency Preparedness Event - Feburary 2020	Customers have identified that they would like more information on how to be prepared in the case of an emergency. Customers have questions on generators, tips, etc. during long power outages.	PUC has either hosted or particpated in emergency preparedness events to provide information for customers on how to be prepared for at least 72 hours, in the case of a prolonged power outage.
Bushplane Days September 2019 [(AffordAbility Fund Trust (AFT)]	Customers have identified that they would like information on government programs that would would help them save money on their energy bills.	Throughout 2019 and 2020, PUC participated in many public events throughout Sault Ste. Marie to promote the AffordAbility Fund Trust program (AFT). The AffordAbility Fund Trust program officially wrapped up in 2021. Throughout the duration of the program commencing in 2017, PUC Services delivered the program to 6,811 customers in the City of Sault Ste. Marie and Espanola. 2,830 customers received appliances (on average 2 per home), and 683 heat pumps were installed. Not only did the program support customers, but it also brought in over 10 million dollars to the local economy. Customer feedback was very positive from participants, with many communicating that they were grateful for the appliances and heat pumps, but also the way in which the program was delivered.
Greyhound Game March 2018 [(AffordAbility Fund Trust (AFT)]	Customers have identified that they would like information on government programs that would would help them save money on their energy bills.	Throughout 2019 and 2020, PUC participated in many public events throughout Sault Ste. Marie to promote the AffordAbility Fund Trust program (AFT). The AffordAbility Fund Trust program officially wrapped up in 2021. Throughout the duration of the program commencing in 2017, PUC Services delivered the program to 6,811 customers in the City of Sault Ste. Marie and Espanola. 2,830 customers received appliances (on average 2 per home), and 683 heat pumps were installed. Not only did the program support customers, but it also brought in over 10 million dollars to the local economy. Customer feedback was very positive from participants, with many communicating that they were grateful for the appliances and heat pumps, but also the way in which the program was delivered."
Kidz Safety Festival 2018 [(AffordAbility Fund Trust (AFT)]	Customers have identified that they would like information on government programs that would would help them save money on their energy bills.	"Throughout 2019 and 2020, PUC participated in many public events throughout Sault Ste. Marie to promote the AffordAbility Fund Trust program (AFT). The AffordAbility Fund Trust program officially wrapped up in 2021. Throughout the duration of the program commencing in 2017, PUC Services delivered the program to 6,811 customers in the City of Sault Ste. Marie and Espanola. 2,830 customers received appliances (on average 2 per home), and 683 heat pumps were installed. Not only did the program support customers, but it also brought in over 10 million dollars to the local economy. Customer feedback was very positive from participants, with many communicating that they were grateful for the appliances and heat pumps, but also the way in which the program was delivered."""
Business Improvement Town Hall April 2018		
Emergency Preparedness Showcase hosted by the City of Sault Ste. Marie - May 2022	Customers have identified that they would like more information on how to be prepared in the case of an emergency. Customers have questions on generators, tips, etc. during long power outages.	PUC has either hosted or particpated in emergency preparedness events to provide information for customers on how to be prepared for at least 72 hours, in the case of a prolonged power outage.
Electrical Safety Awareness Training - 2019	Commercial PUC customers have identified that they would like access to electrical safety training for their employees.	In 2019, PUC offered electrical safety awareness training for educational purposes to workplace in the City of Sault Ste. Marie. PUC powerline technicians provided the training to increase knowledge about hazards when working around electricity. The goal was to provide workers with a
ATLAS phone notification system - planned electrical outages	Customers have identified that they would like to be informed when there are planned outages or construction taking place that will affect their electrical services.	PUC utilizes a phone notification system called ATLAS. When there are any planned electrical outages in order to improve reliability, PUC sends out automated calls to all customers affected with information on timing and details on why the outage is taking place.

APPENDIX L

Customer

Engagement Survey

Phase 1

2021- PUC Distribution's Customer Engagement Survey

Wednesday, October 13, 2021

906

Total Responses

Date Created: Friday, August 06, 2021

Complete Responses: 906

Introduction Page

Welcome,

Thank you for participating in PUC Distribution’s Customer Engagement Survey for its 2023 Cost of Service Application. We appreciate you taking the time to answer the questions and as a result you will be entered into a draw to win 1 of $50 gift cards to a local restaurant or café.

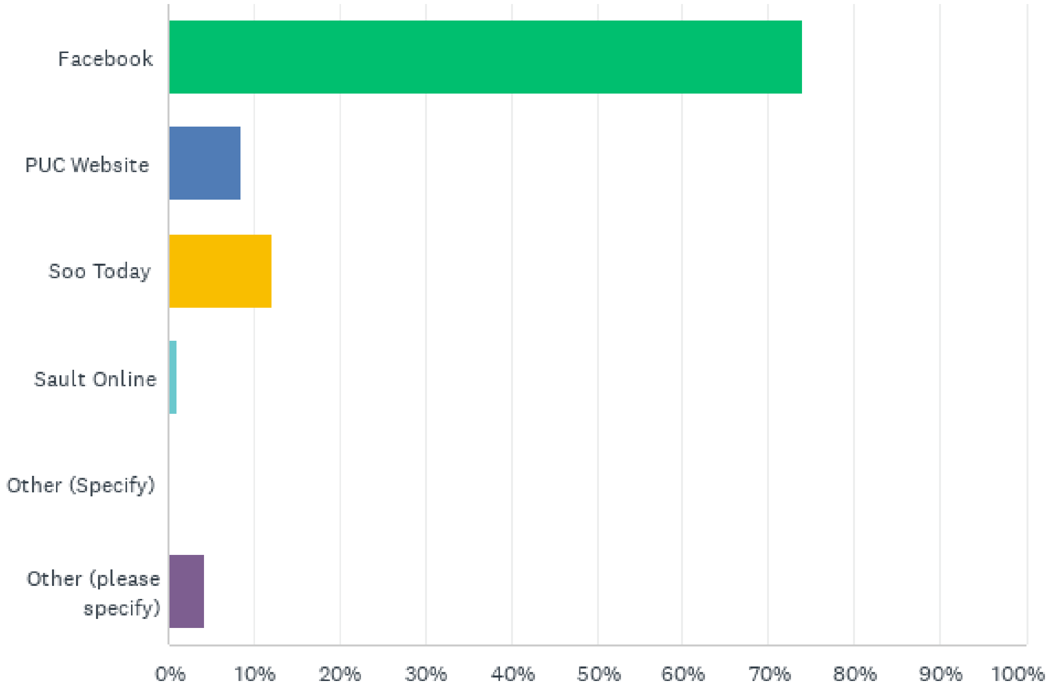
We are applying to the Ontario Energy Board (“OEB”) for approval to increase PUC’s portion of the electricity bill, also known as the delivery rate. If approved, this will come into effect May 1, 2023.

The OEB's Cost of Service application typically occurs every five years and determines what each LDC can charge for its distribution (delivery) rate. PUC is currently applying to the OEB for approval to increase the distribution rates for May 1, 2023. The last Cost of Service rate application to increase distribution rates was in 2018. Since then, inflationary increases have occurred each year as approved by the OEB.

This survey will be part 1 of a 2-part survey. We will ask you some general questions about what matters most to you in regards to PUC’s electricity distribution system. We look forward to your participation for phase 2 coming in Early 2022. Please keep an eye on our website, social media platforms, Soo today and Sault Online for a chance to win more prizes for providing your feedback.

Q1: How did you hear about this survey?

Answered: 906   Skipped: 0



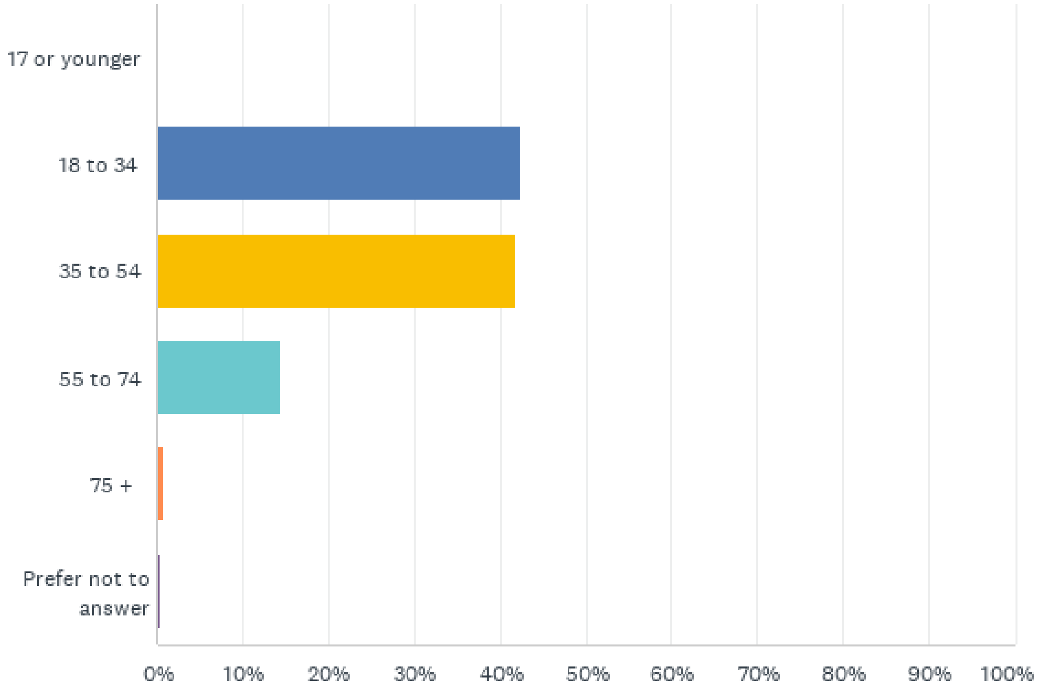
Q1: How did you hear about this survey?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Facebook	73.95%	670
PUC Website	8.61%	78
Soo Today	12.14%	110
Sault Online	1.10%	10
Other (Specify)	0.00%	0
Other (please specify)	4.19%	38
TOTAL		906

Q2: What is your age?

Answered: 906   Skipped: 0



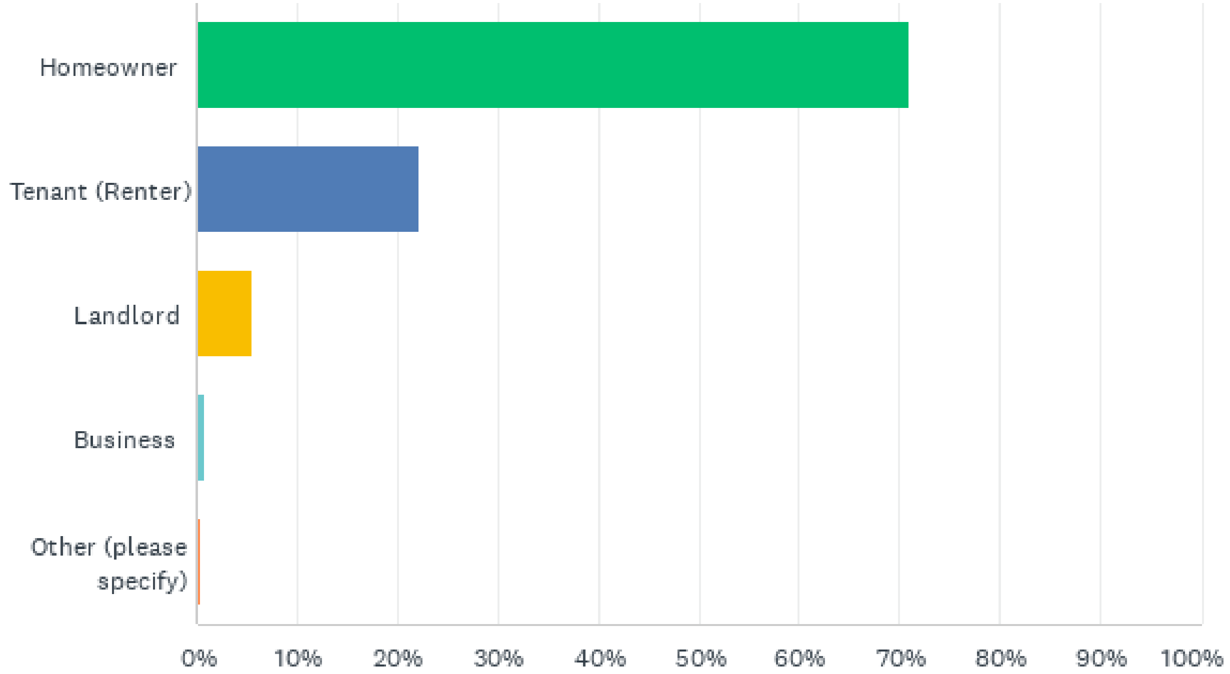
Q2: What is your age?

Answered: 906 Skipped: 0

ANSWER CHOICES	RESPONSES	
17 or younger	0.11%	1
18 to 34	42.49%	385
35 to 54	41.72%	378
55 to 74	14.46%	131
75 +	0.88%	8
Prefer not to answer	0.33%	3
TOTAL		906

Q3: Which of the following best describes you?

Answered: 906   Skipped: 0



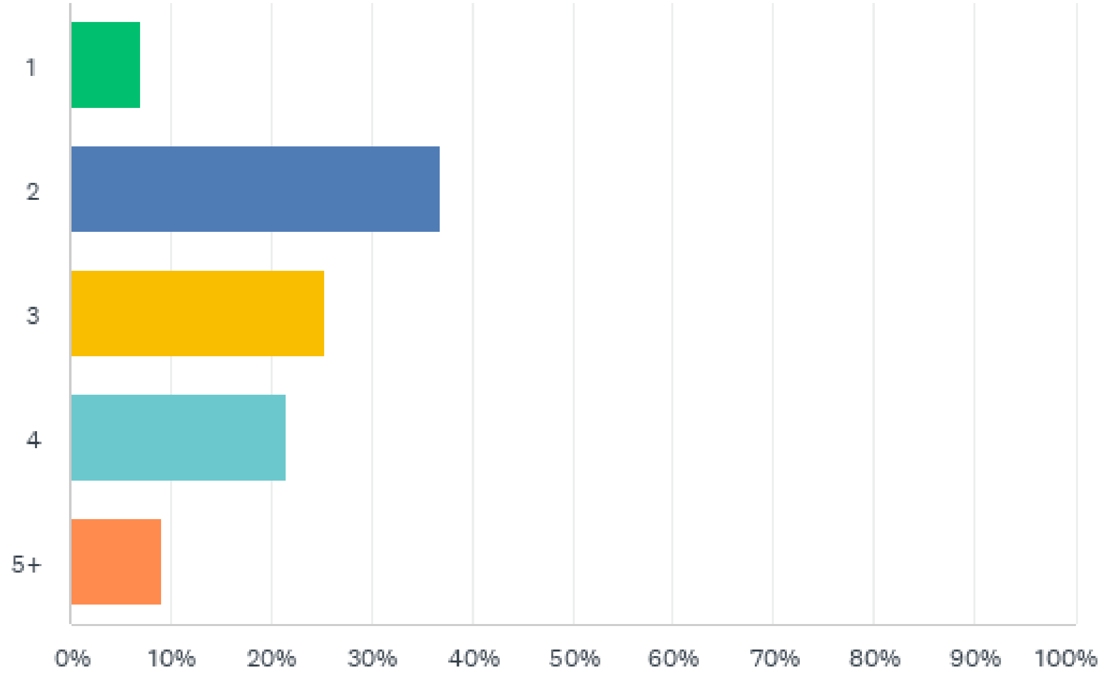
Q3: Which of the following best describes you?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Homeowner	70.97%	643
Tenant (Renter)	22.08%	200
Landlord	5.63%	51
Business	0.88%	8
Other (please specify)	0.44%	4
TOTAL		906

Q4: Including yourself, how many people live in your household?

Answered: 906   Skipped: 0



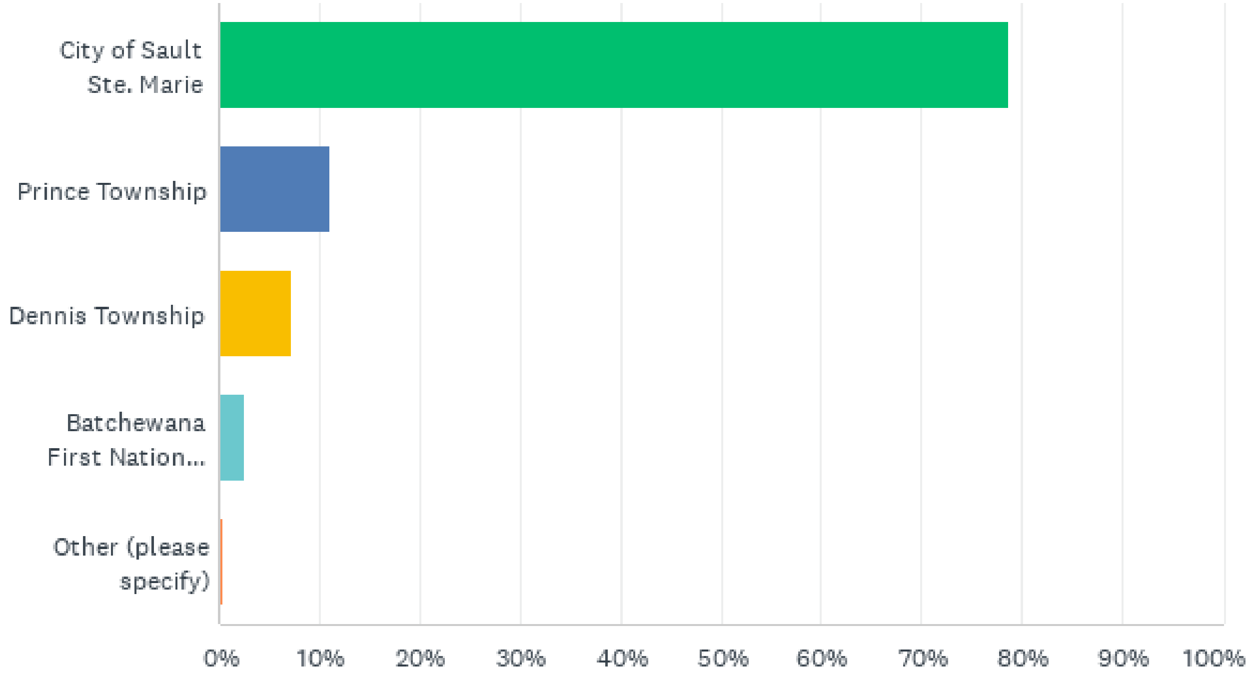
Q4: Including yourself, how many people live in your household?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
1	6.95%	63
2	36.87%	334
3	25.28%	229
4	21.63%	196
5+	9.27%	84
TOTAL		906

Q5: Where do you live within PUC Distribution’s service area?

Answered: 906   Skipped: 0



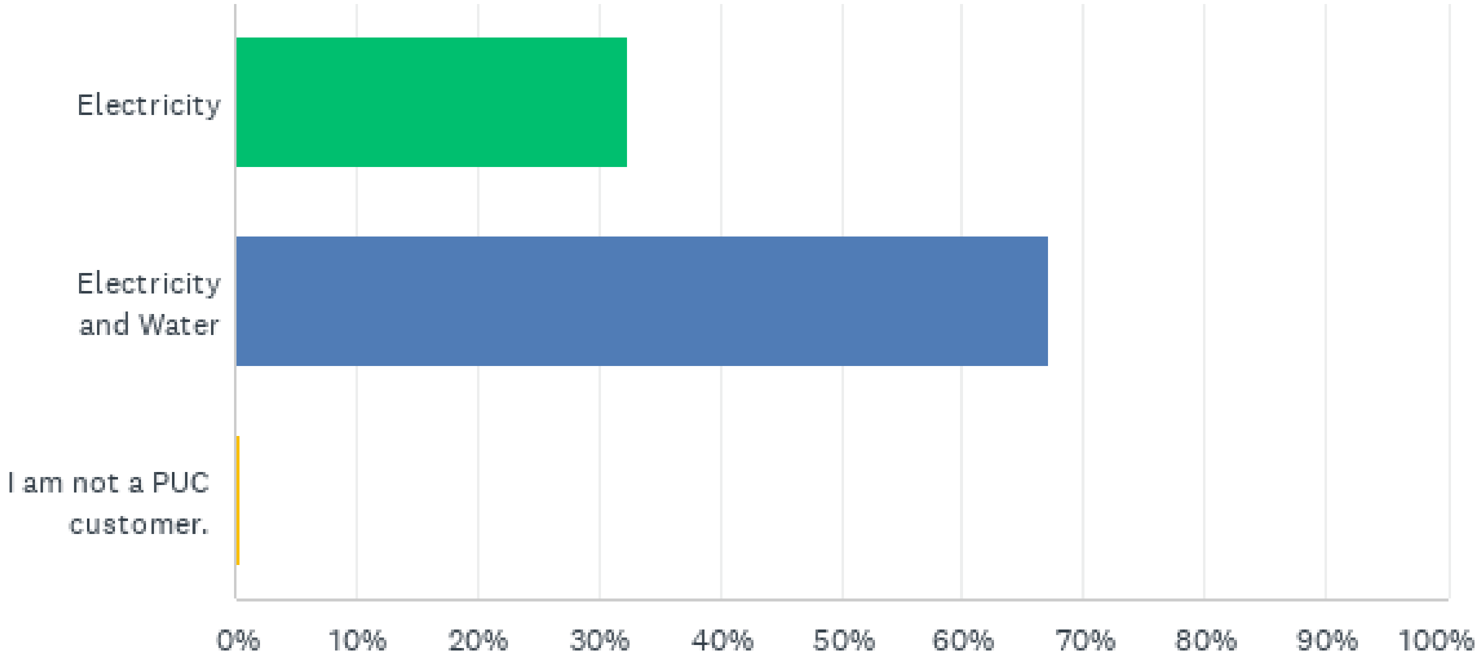
Q5: Where do you live within PUC Distribution’s service area?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
City of Sault Ste. Marie	78.70%	713
Prince Township	11.04%	100
Dennis Township	7.17%	65
Batchewana First Nation Rankin Reserve	2.65%	24
Other (please specify)	0.44%	4
TOTAL		906

Q6: What services do you currently receive from PUC?

Answered: 906   Skipped: 0



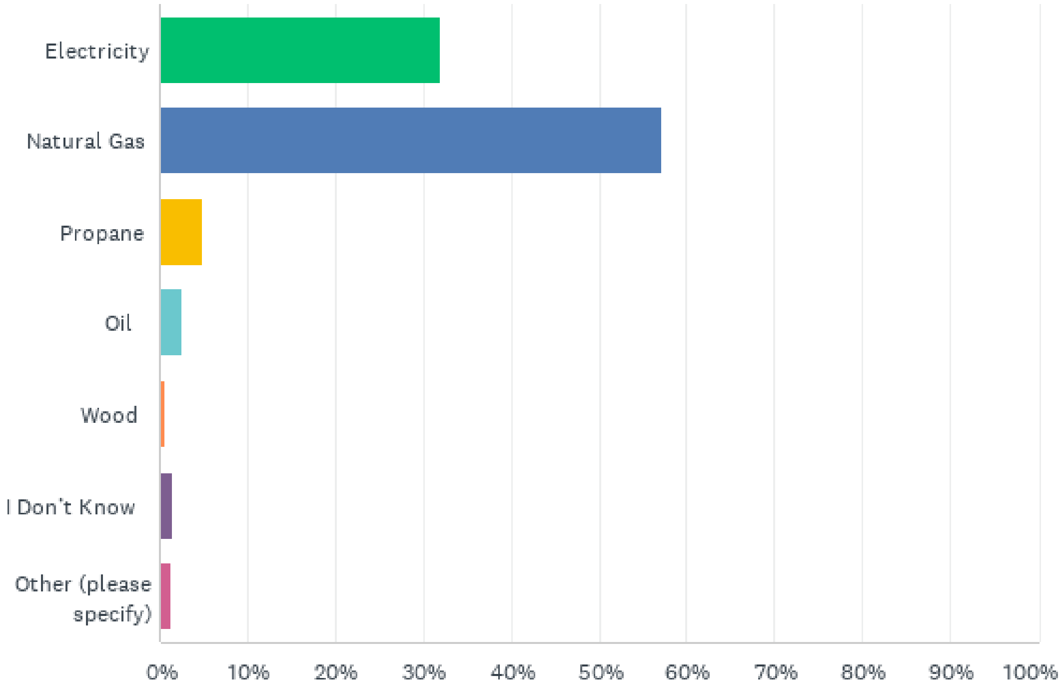
Q6: What services do you currently receive from PUC?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Electricity	32.45%	294
Electricity and Water	67.22%	609
I am not a PUC customer.	0.33%	3
TOTAL		906

Q7: Which of the following is your primary source of heating?

Answered: 906   Skipped: 0



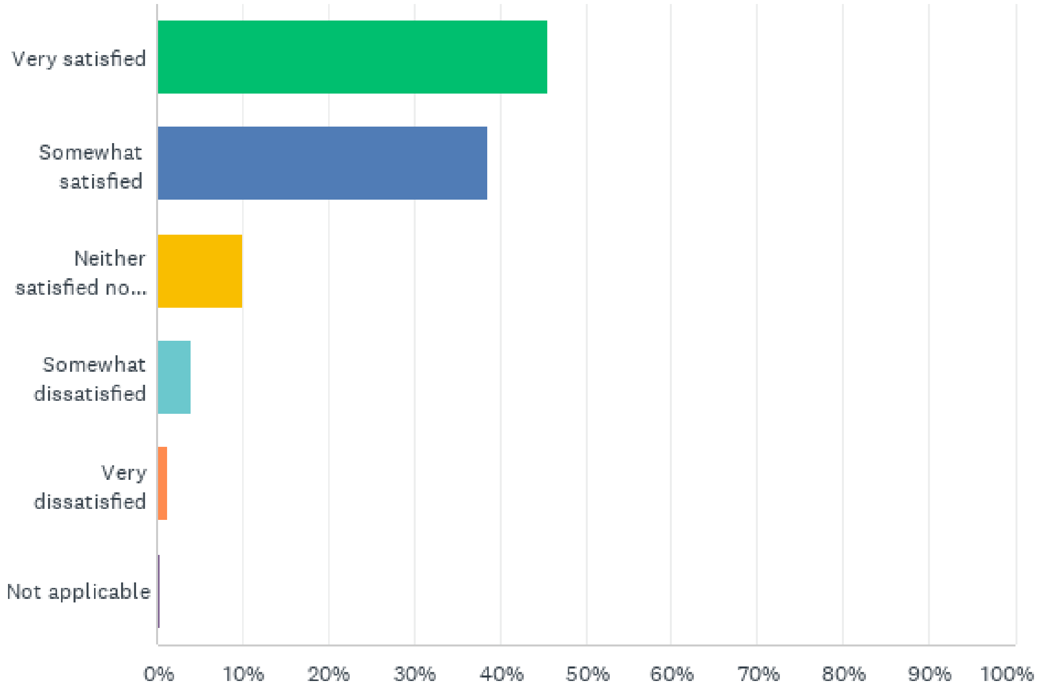
Q7: Which of the following is your primary source of heating?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Electricity	31.90%	289
Natural Gas	57.06%	517
Propane	4.86%	44
Oil	2.65%	24
Wood	0.66%	6
I Don't Know	1.55%	14
Other (please specify)	1.32%	12
TOTAL		906

Q8: How satisfied are you with the overall service(s) you receive?

Answered: 906   Skipped: 0



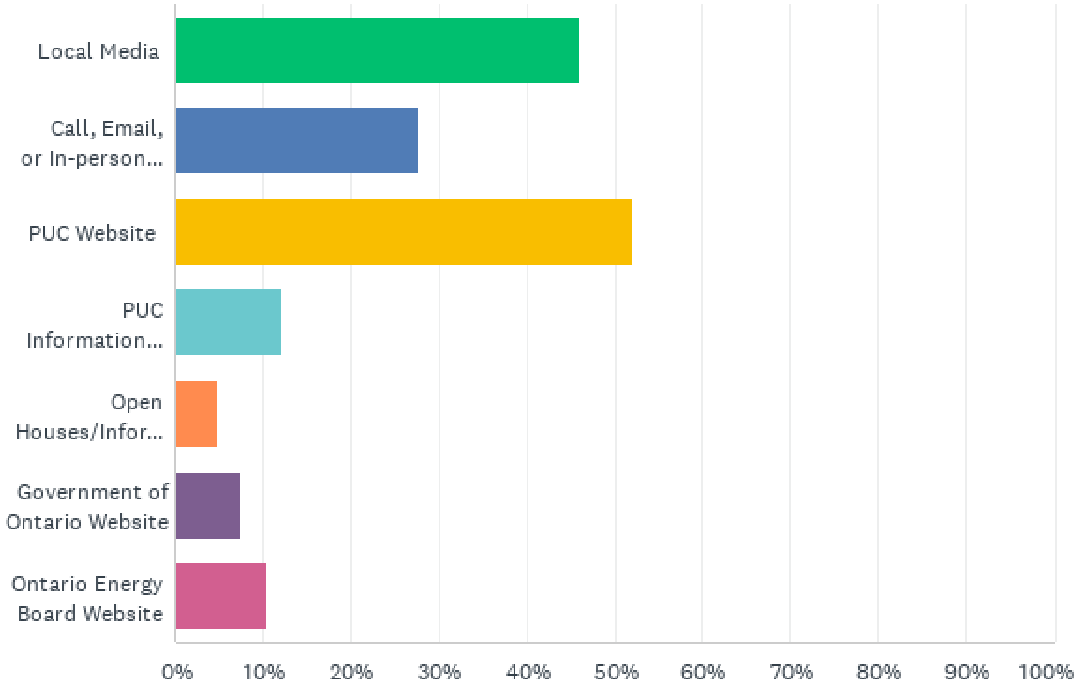
Q8: How satisfied are you with the overall service(s) you receive?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Very satisfied	45.70%	414
Somewhat satisfied	38.52%	349
Neither satisfied nor dissatisfied	10.04%	91
Somewhat dissatisfied	3.97%	36
Very dissatisfied	1.32%	12
Not applicable	0.44%	4
TOTAL		906

Q9: Where do you currently find information on things like electricity rates, conservation tips, and consumption/usage information? Please select ALL that apply.

Answered: 906 Skipped: 0



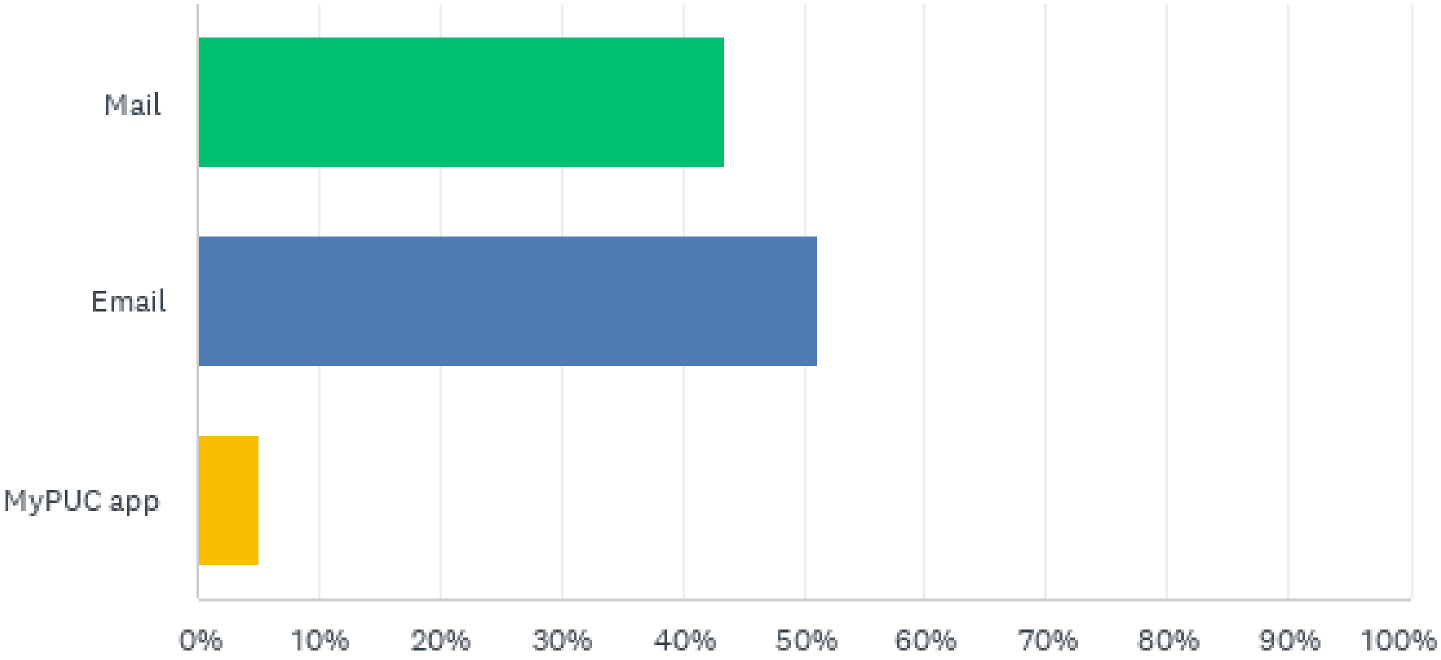
Q9: Where do you currently find information on things like electricity rates, conservation tips, and consumption/usage information? Please select ALL that apply.

Answered: 906 Skipped: 0

ANSWER CHOICES	RESPONSES	
Local Media	46.14%	418
Call, Email, or In-person at the PUC Office	27.81%	252
PUC Website	51.99%	471
PUC Information Booths (i.e., Home/Trade Shows.)	12.25%	111
Open Houses/Information Sessions	4.86%	44
Government of Ontario Website	7.51%	68
Ontario Energy Board Website	10.49%	95
Total Respondents: 906		

Q10: How do you receive your PUC Bill?

Answered: 906   Skipped: 0



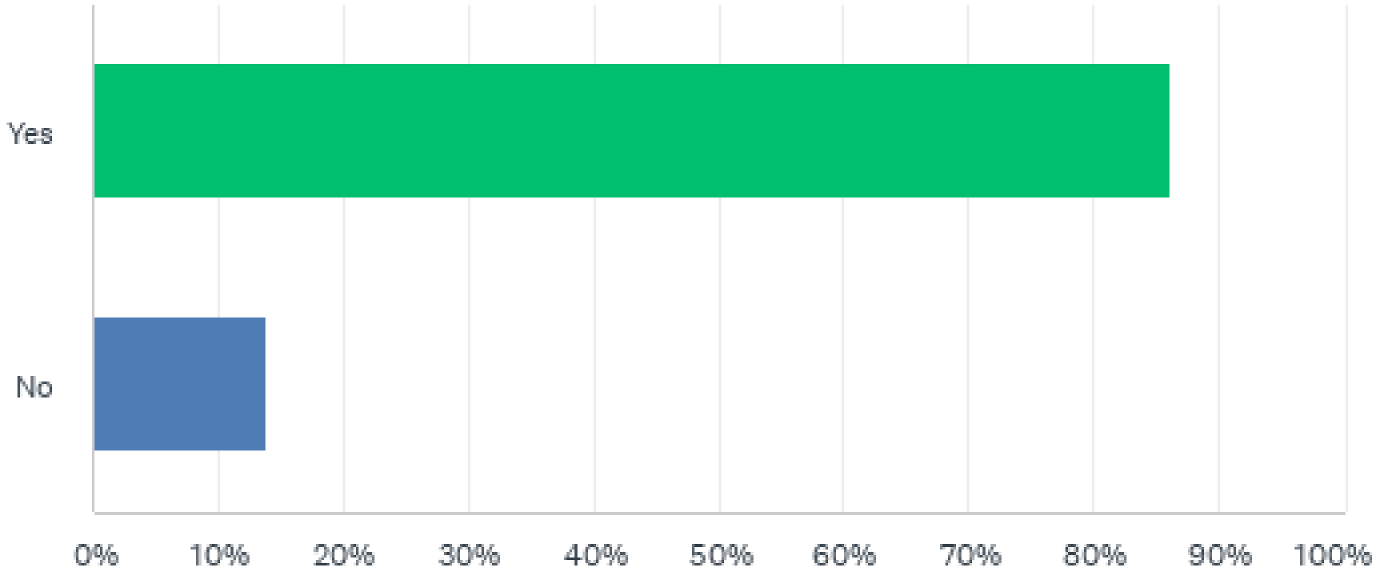
Q10: How do you receive your PUC Bill?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Mail	43.60%	395
Email	51.21%	464
MyPUC app	5.19%	47
TOTAL		906

Q11: Have you ever visited www.ssmpuc.com

Answered: 906   Skipped: 0



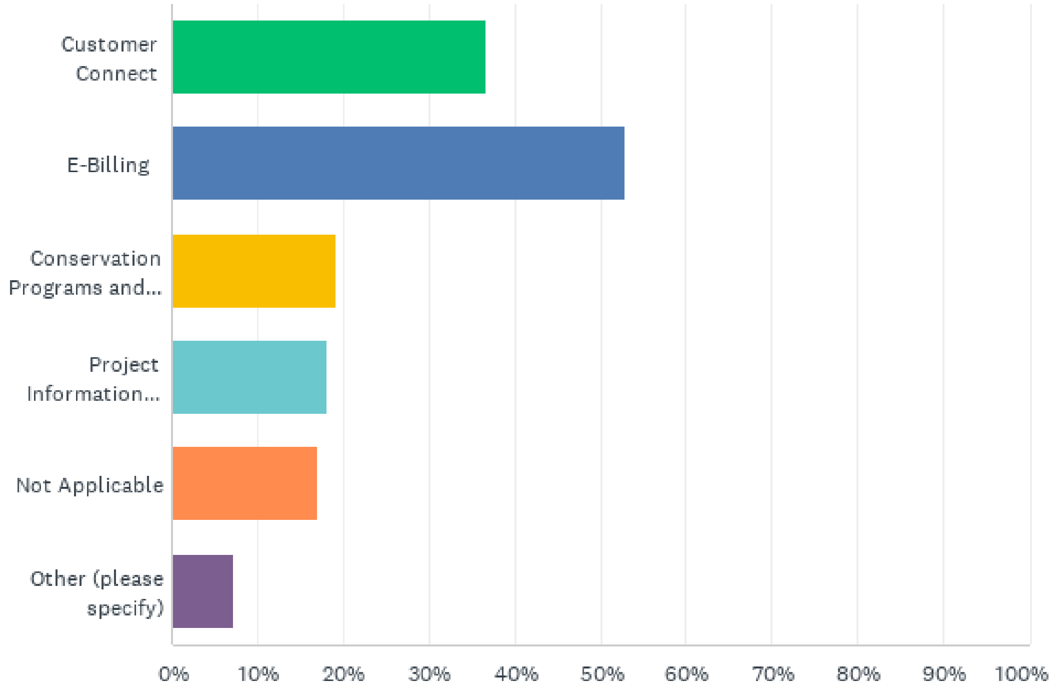
Q11: Have you ever visited www.ssmpuc.com

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Yes	86.20%	781
No	13.80%	125
TOTAL		906

Q12: Please select all the reasons you have visited PUC's website in the last 6 months from the list below. If not, please choose Not Applicable.

Answered: 904   Skipped: 2



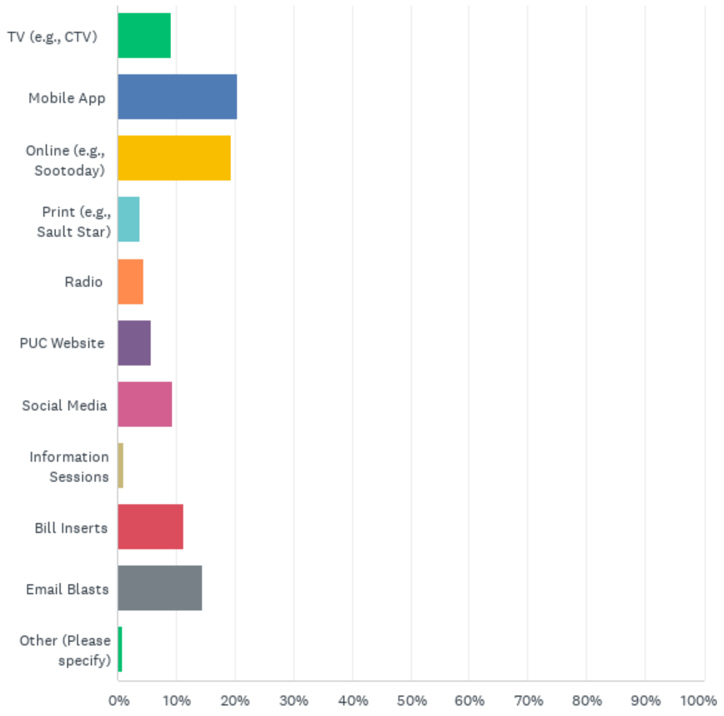
Q12: Please select all the reasons you have visited PUC's website in the last 6 months from the list below. If not, please choose Not Applicable.

Answered: 904   Skipped: 2

ANSWER CHOICES	RESPONSES	
Customer Connect	36.73%	332
E-Billing	52.88%	478
Conservation Programs and Advice	19.25%	174
Project Information Search (e.g., Overhead line work in your neighbourhood)	18.14%	164
Not Applicable	17.15%	155
Other (please specify)	7.19%	65
Total Respondents: 904		

Q14: To improve our customer communication, please choose your preferred method for PUC to communicate with you.

Answered: 906   Skipped: 0



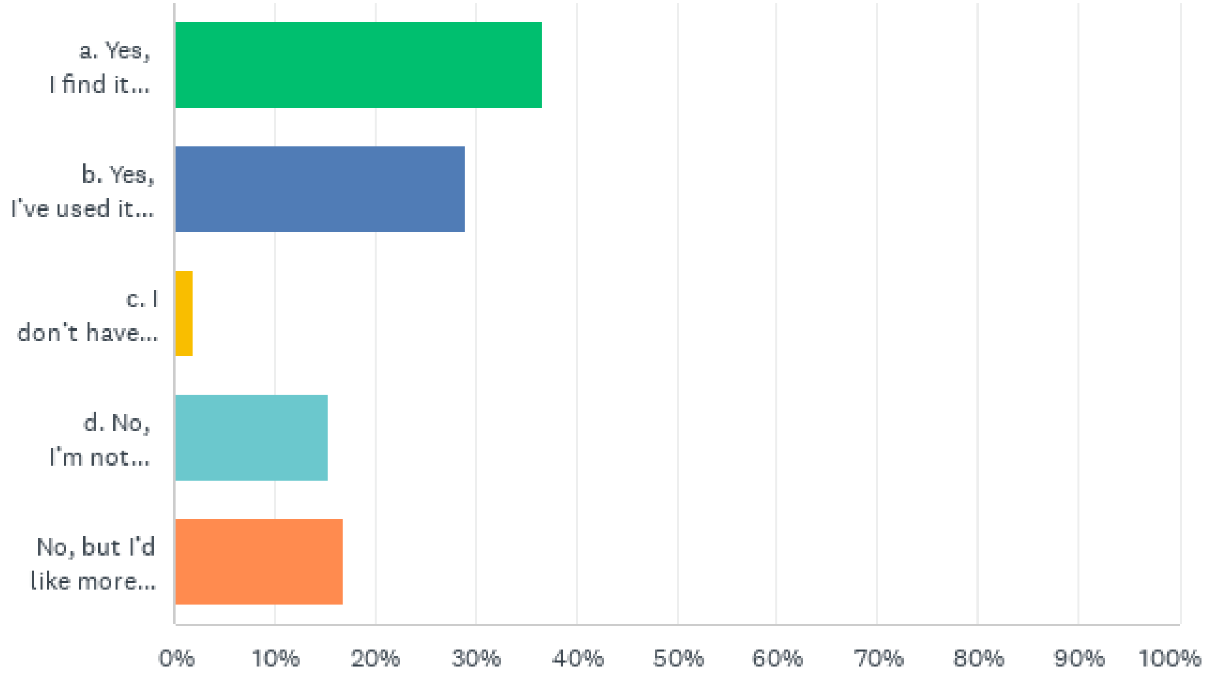
Q14: To improve our customer communication, please choose your preferred method for PUC to communicate with you.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
TV (e.g., CTV)	9.16%	83
Mobile App	20.42%	185
Online (e.g., Sootoday)	19.32%	175
Print (e.g., Sault Star)	3.75%	34
Radio	4.53%	41
PUC Website	5.85%	53
Social Media	9.38%	85
Information Sessions	0.99%	9
Bill Inserts	11.37%	103
Email Blasts	14.46%	131
Other (Please specify)	0.77%	7
TOTAL		906

Q15: To increase awareness of electricity usage, PUC offers an online energy usage tool called, Customer Connect. Have you ever used it to monitor your hourly, daily and weekly electrical usage?

Answered: 906   Skipped: 0



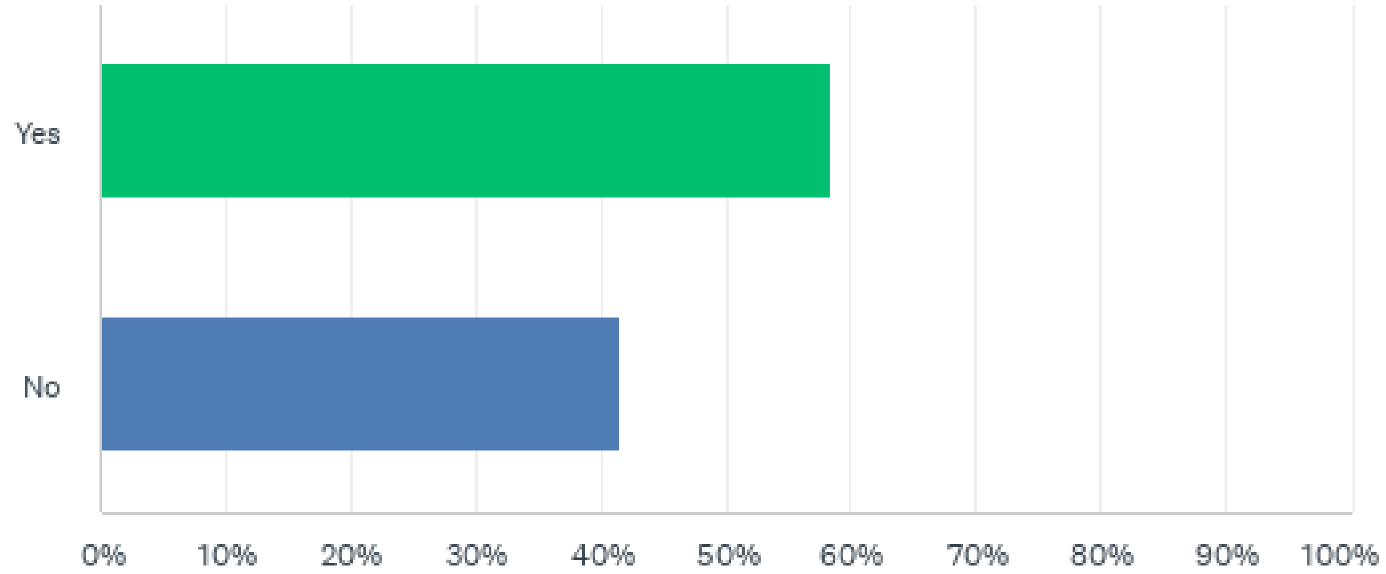
Q15: To increase awareness of electricity usage, PUC offers an online energy usage tool called, Customer Connect. Have you ever used it to monitor your hourly, daily and weekly electrical usage?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
a. Yes, I find it useful to visually track usage.	36.75%	333
b. Yes, I've used it a few times.	29.03%	263
c. I don't have access to a computer.	1.99%	18
d. No, I'm not interested in online services.	15.34%	139
No, but I'd like more information about Customer Connect and here is my email address	16.89%	153
TOTAL		906

Q16: Did you know we have our own app called MyPUC before participating in this survey?

Answered: 906 Skipped: 0



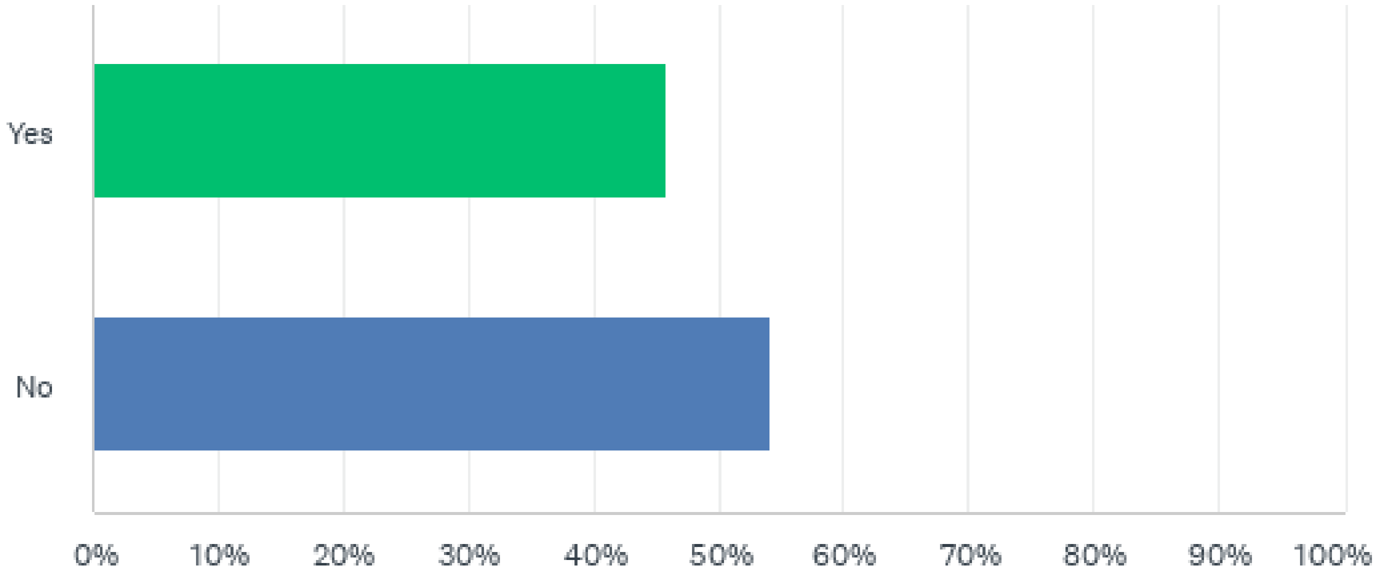
Q16: Did you know we have our own app called MyPUC before participating in this survey?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Yes	58.50%	530
No	41.50%	376
TOTAL		906

Q17: Have you downloaded the app?

Answered: 906   Skipped: 0



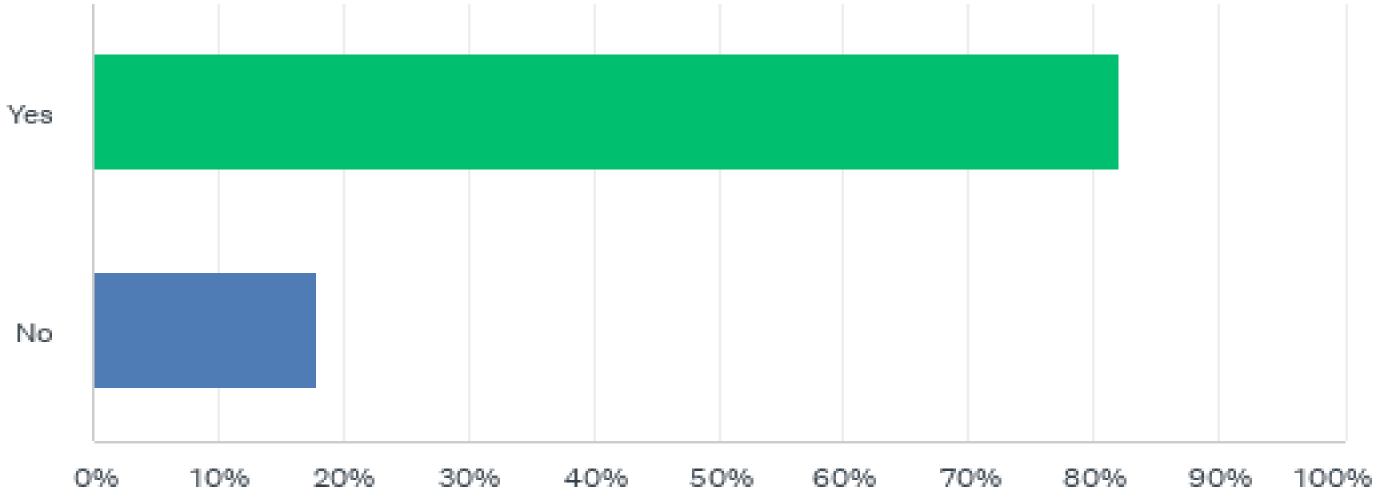
Q17: Have you downloaded the app?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Yes	45.92%	416
No	54.08%	490
TOTAL		906

Q18: The MyPUC App allows you to track your energy consumption, receive outage notifications, access billing information, and receive conservations tips. Based on these features, do you believe you will download the app? (click here for instruction on how to download)

Answered: 906   Skipped: 0



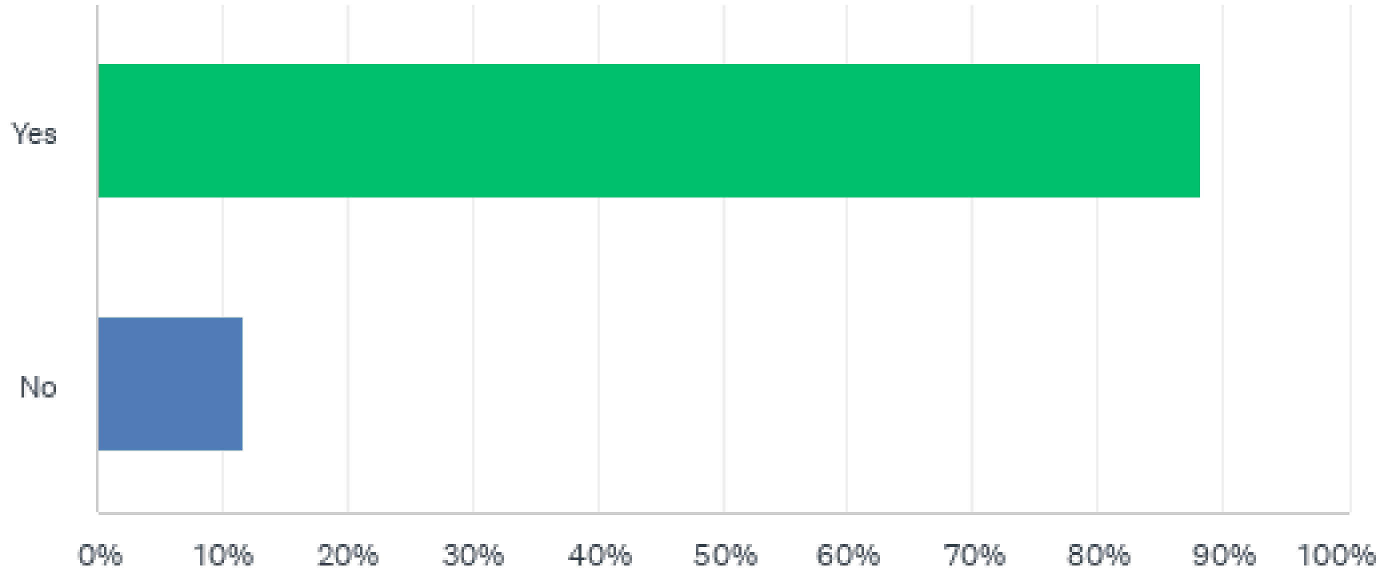
Q18: The MyPUC App allows you to track your energy consumption, receive outage notifications, access billing information, and receive conservations tips. Based on these features, do you believe you will download the app? (click here for instruction on how to download)

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Yes	82.12%	744
No	17.88%	162
TOTAL		906

Q19: Did you know PUC offers E-Billing Services? This is an effective way to receive your bill notification and make arrangements to pay. (Click here to sign up for E-billing)

Answered: 906   Skipped: 0



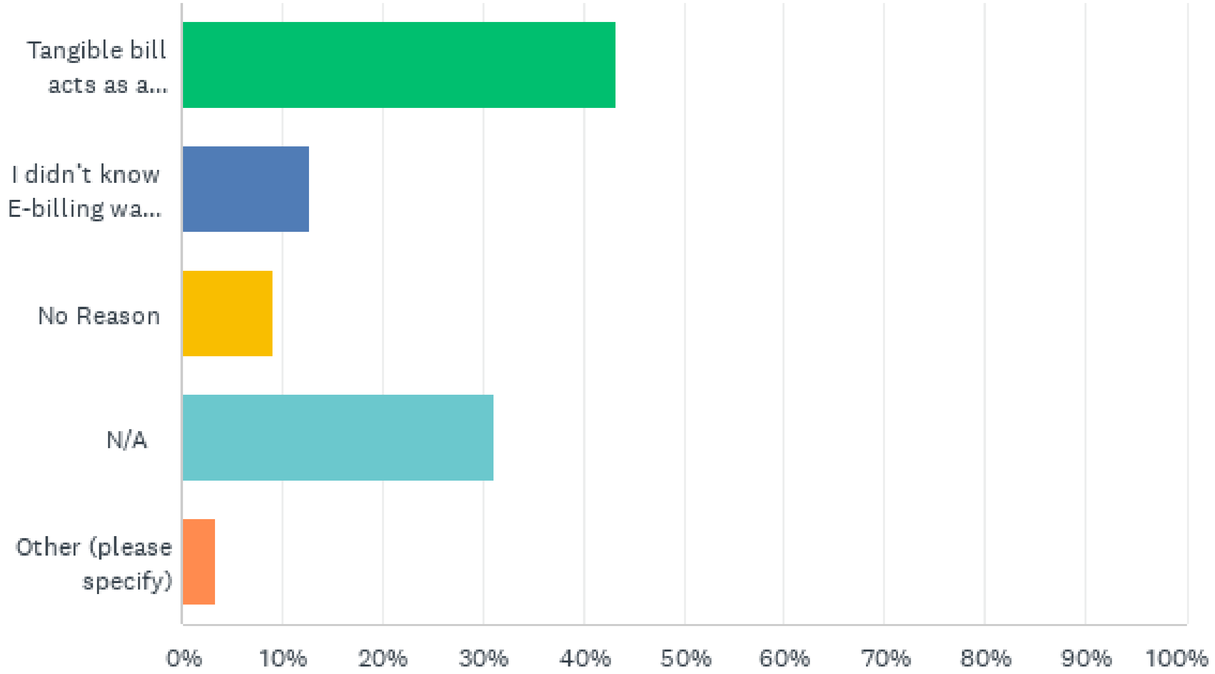
Q19: Did you know PUC offers E-Billing Services? This is an effective way to receive your bill notification and make arrangements to pay. (Click here to sign up for E-billing)

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Yes	88.30%	800
No	11.70%	106
TOTAL		906

Q20: If you receive a Paper Bill, we would like you to help us understand your billing preferences? If you receive an E-Bill already, please select N/A.

Answered: 906 Skipped: 0



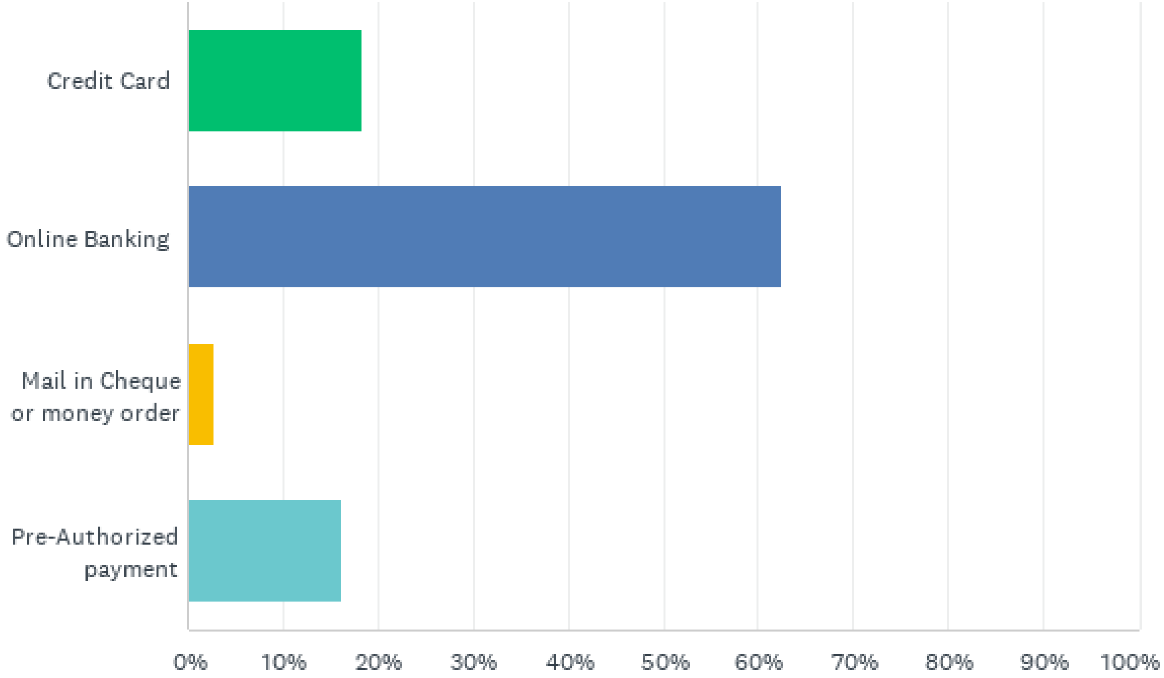
Q20: If you receive a Paper Bill, we would like you to help us understand your billing preferences? If you receive an E-Bill already, please select N/A.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Tangible bill acts as a reminder to pay	43.38%	393
I didn't know E-billing was an available option	12.69%	115
No Reason	9.27%	84
N/A	31.24%	283
Other (please specify)	3.42%	31
TOTAL		906

Q21: How do you currently pay your PUC Bill?

Answered: 906   Skipped: 0



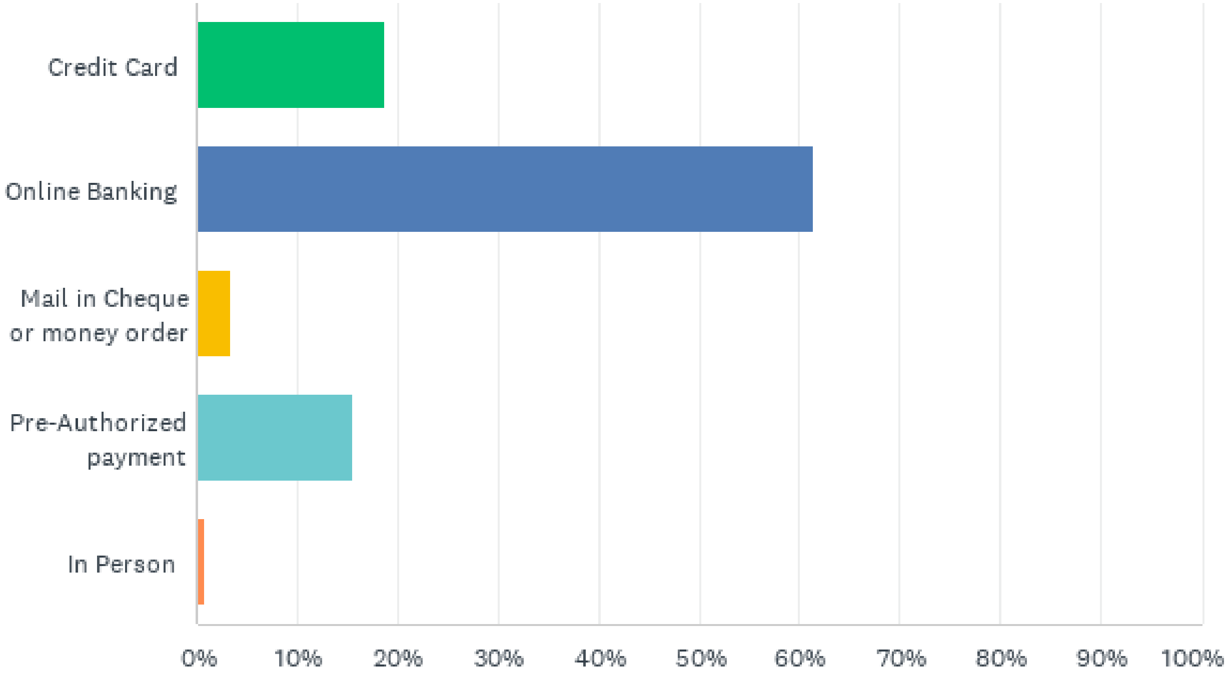
Q21: How do you currently pay your PUC Bill?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Credit Card	18.43%	167
Online Banking	62.47%	566
Mail in Cheque or money order	2.87%	26
Pre-Authorized payment	16.23%	147
TOTAL		906

Q22: What is your preferred method of payment?

Answered: 906 Skipped: 0



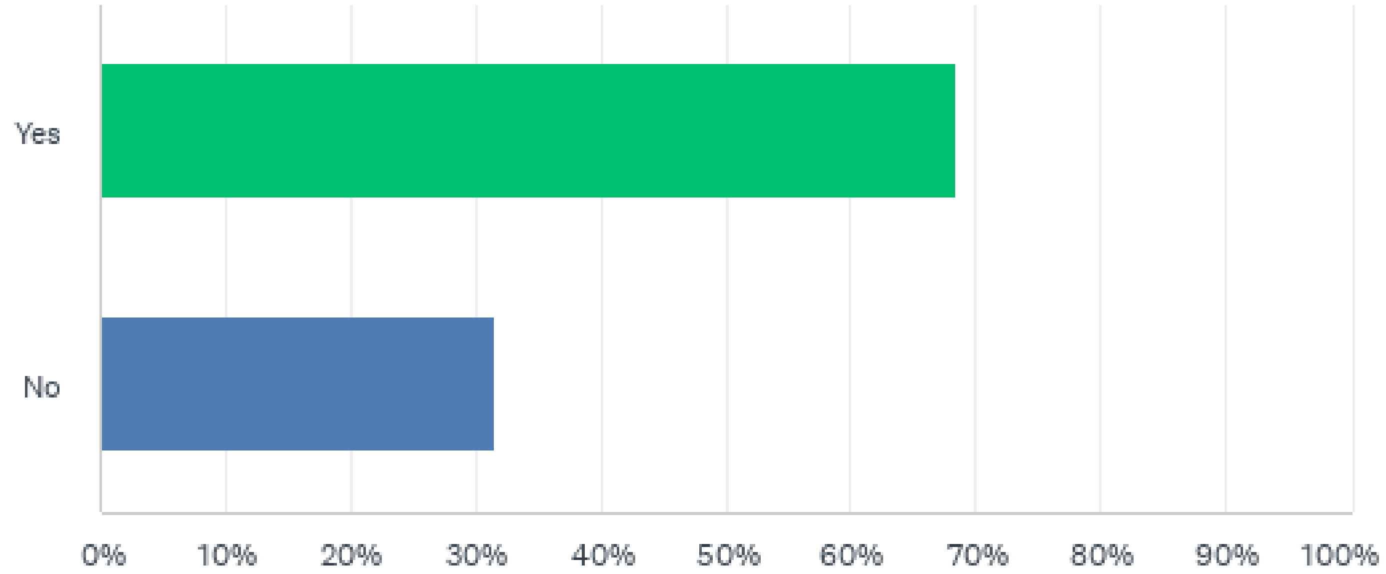
Q22: What is your preferred method of payment?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Credit Card	18.76%	170
Online Banking	61.48%	557
Mail in Cheque or money order	3.31%	30
Pre-Authorized payment	15.56%	141
In Person	0.88%	8
TOTAL		906

Q23: Did you know that prior to your bill due date you can make multiple smaller payments that combine to the total due on your due date?

Answered: 906   Skipped: 0



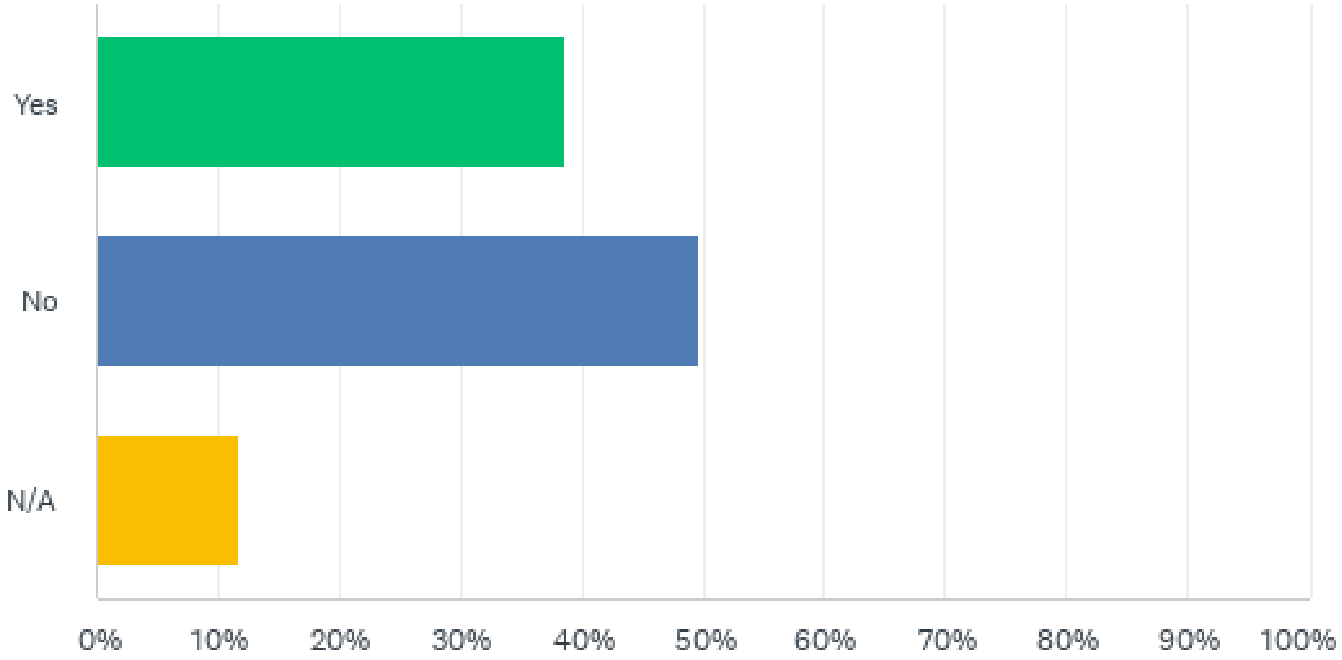
Q23: Did you know that prior to your bill due date you can make multiple smaller payments that combine to the total due on your due date?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Yes	68.43%	620
No	31.57%	286
TOTAL		906

Q24: Would you be interested in hearing more about pre-authorized payments?

Answered: 906   Skipped: 0



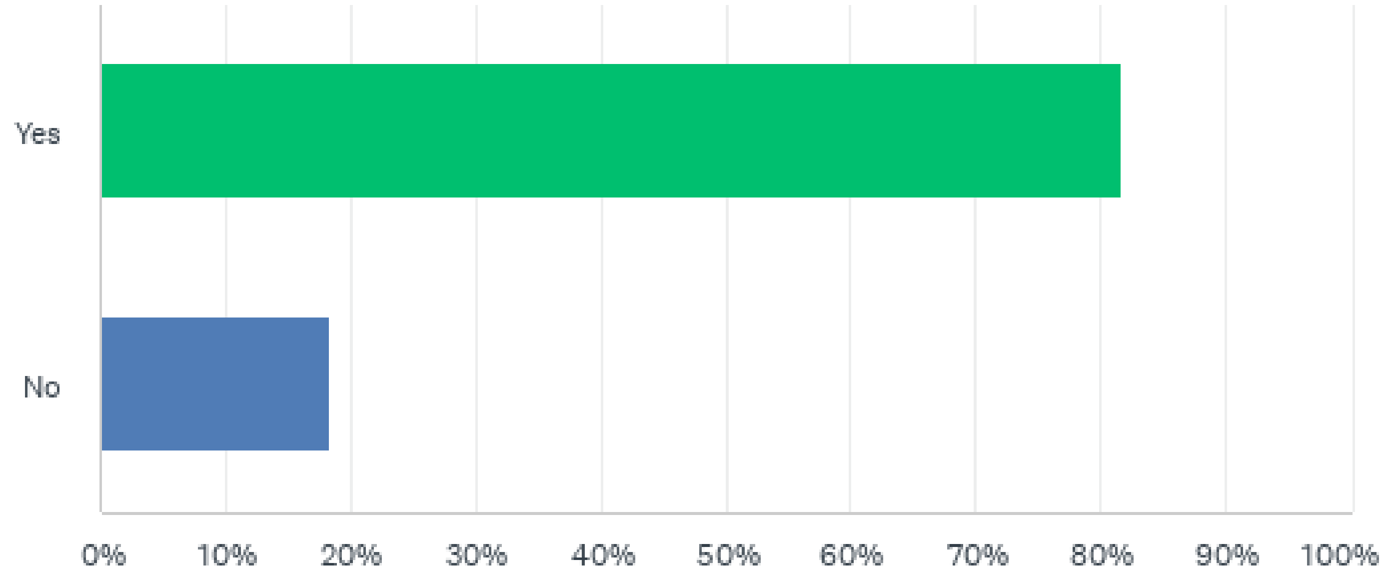
Q24: Would you be interested in hearing more about pre-authorized payments?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Yes	38.52%	349
No	49.67%	450
N/A	11.81%	107
TOTAL		906

Q25: Are you aware that you can choose between time of use pricing or tiered pricing for the cost of power?

Answered: 906   Skipped: 0



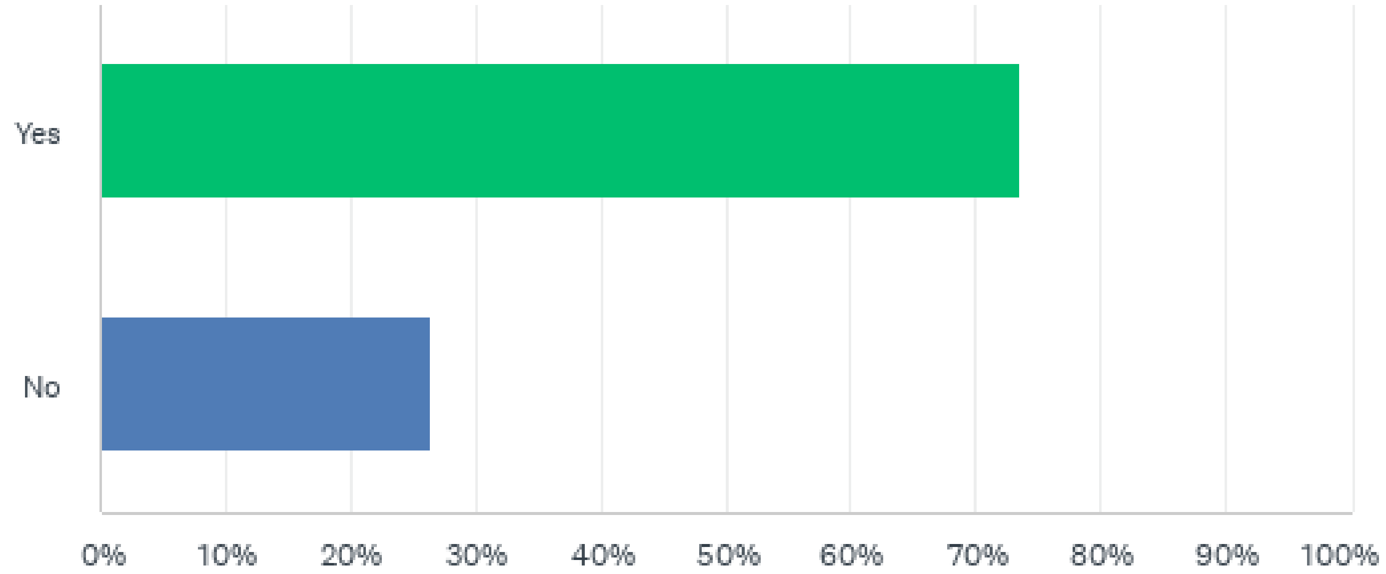
Q25: Are you aware that you can choose between time of use pricing or tiered pricing for the cost of power?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Yes	81.68%	740
No	18.32%	166
TOTAL		906

Q26: Would you be interested in the tools available to help you choose between Time of Use pricing or tiered pricing and how it can possibly save you money on your bill?

Answered: 906   Skipped: 0



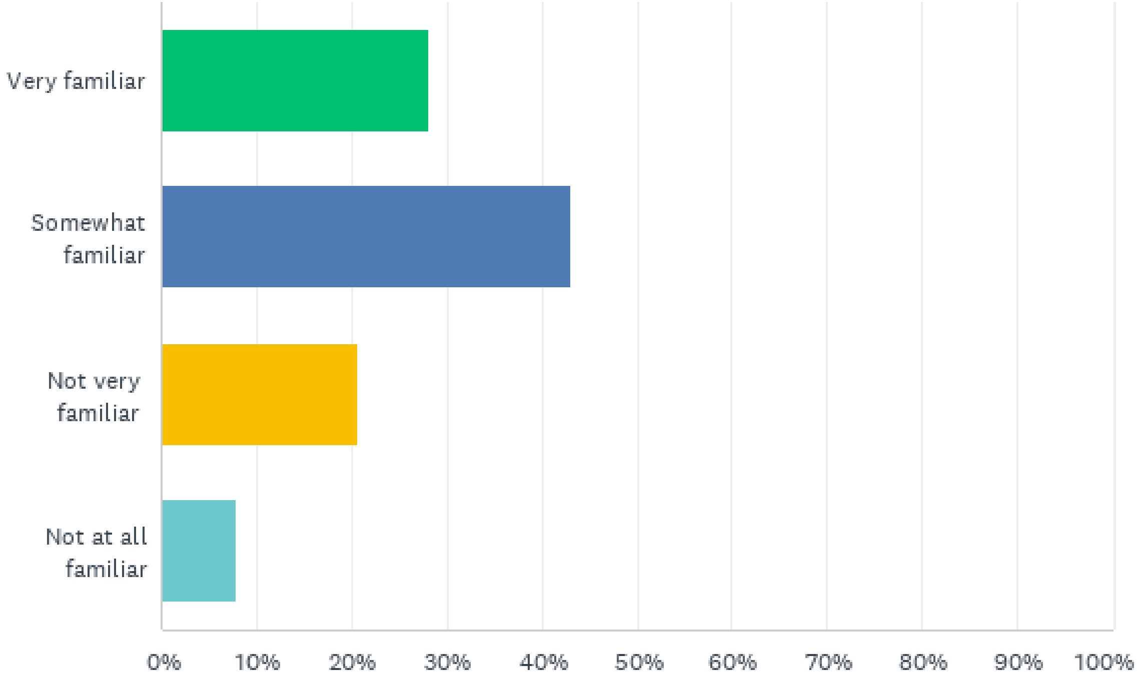
Q26: Would you be interested in the tools available to help you choose between Time of Use pricing or tiered pricing and how it can possibly save you money on your bill?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Yes	73.51%	666
No	26.49%	240
TOTAL		906

Q27: Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate. Before this video, how familiar were you with Ontario’s electricity system and PUC Distribution’s role?

Answered: 906   Skipped: 0



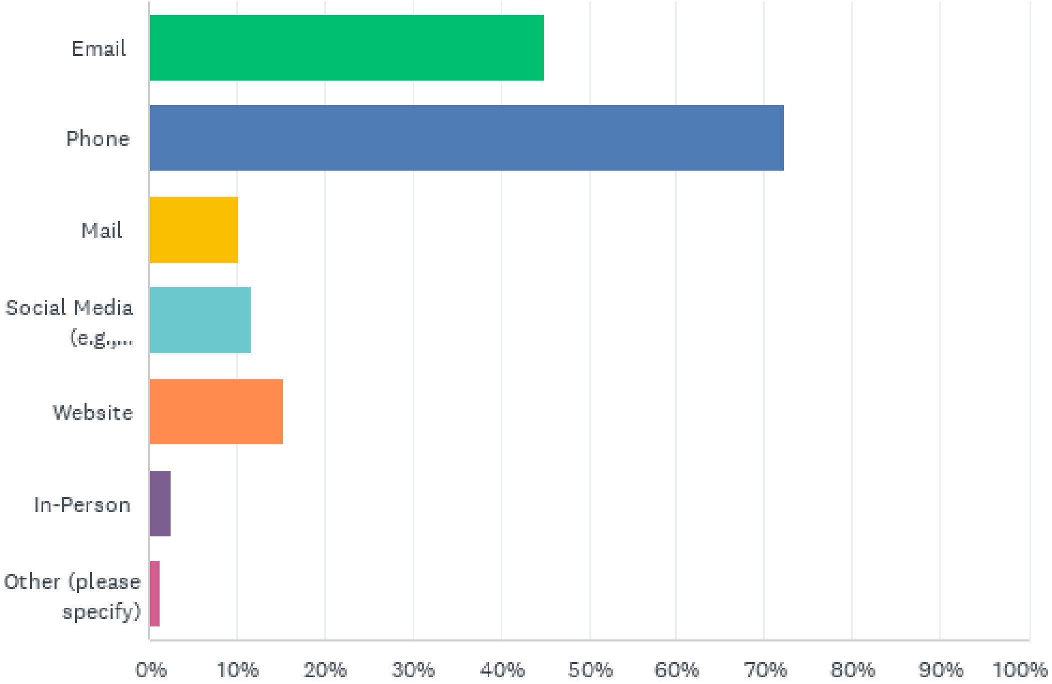
Q27: Please watch this video before completing the questions below. Please ensure your volume is on so you can hear the information. Closed captioning is available for those that need it to participate. Before this video, how familiar were you with Ontario’s electricity system and PUC Distribution’s role?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Very familiar	28.15%	255
Somewhat familiar	43.16%	391
Not very familiar	20.75%	188
Not at all familiar	7.95%	72
TOTAL		906

Q28: When you have an electrical service issue, what is your preferred method to contact PUC for assistance? Please select ALL that apply.

Answered: 906   Skipped: 0



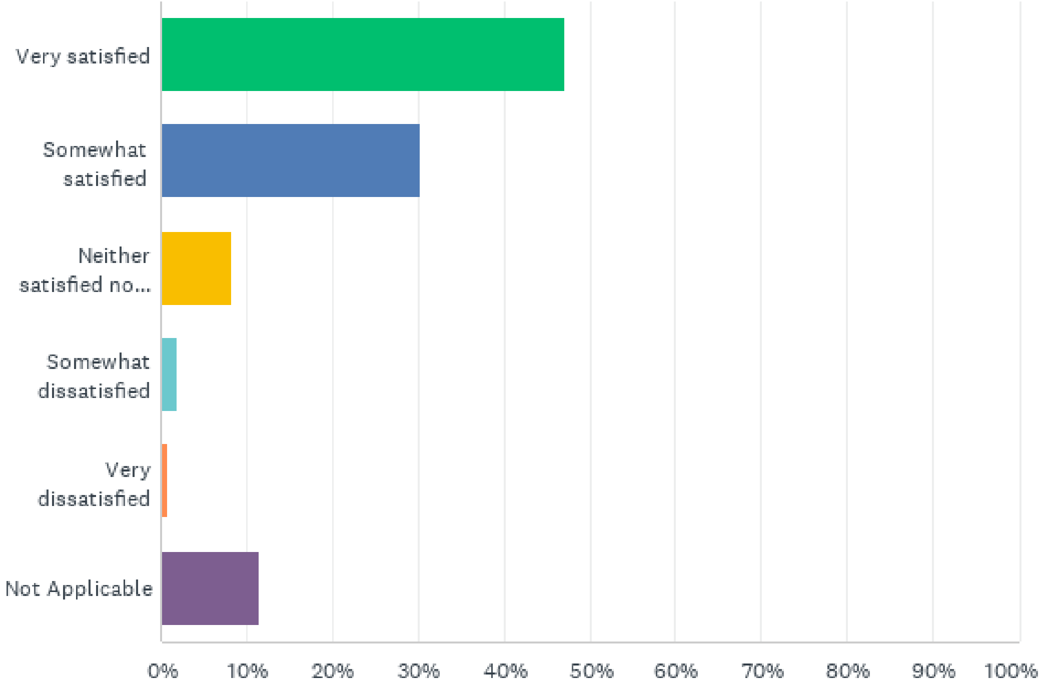
Q28: When you have an electrical service issue, what is your preferred method to contact PUC for assistance? Please select ALL that apply.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Email	45.03%	408
Phone	72.19%	654
Mail	10.15%	92
Social Media (e.g., Facebook, Twitter)	11.70%	106
Website	15.34%	139
In-Person	2.65%	24
Other (please specify)	1.32%	12
Total Respondents: 906		

Q29: How satisfied were you with the Customer service you received?

Answered: 906   Skipped: 0



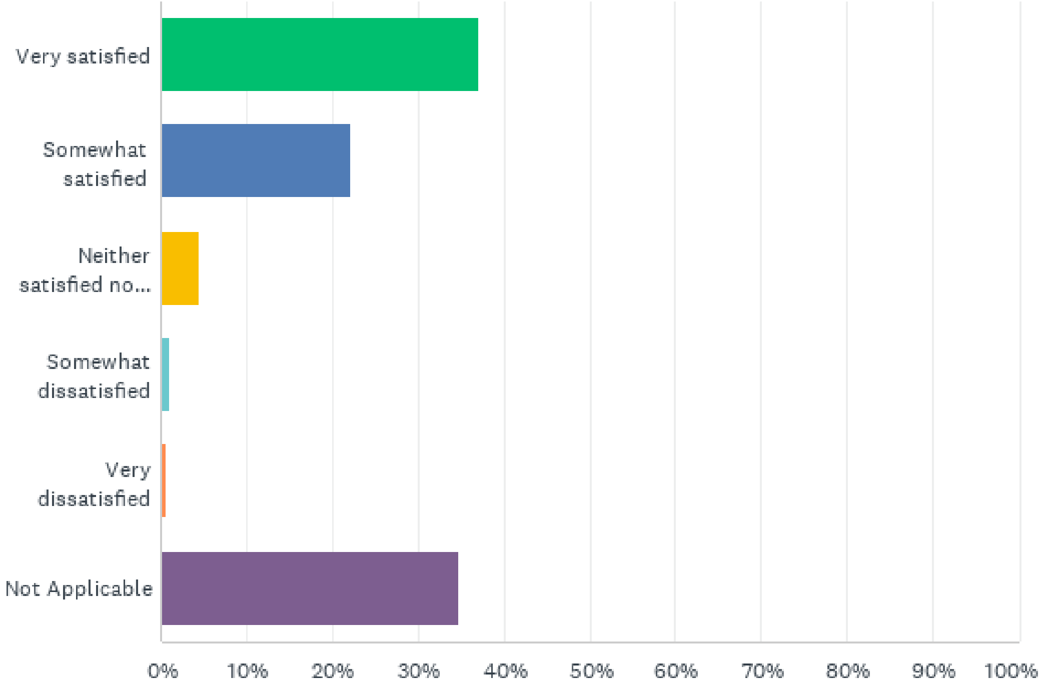
Q29: How satisfied were you with the Customer service you received?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Very satisfied	47.13%	427
Somewhat satisfied	30.35%	275
Neither satisfied nor dissatisfied	8.28%	75
Somewhat dissatisfied	1.99%	18
Very dissatisfied	0.77%	7
Not Applicable	11.48%	104
TOTAL		906

Q30: Please tell us how you felt about an experience with a PUC field representative that visited your home/business with regards to an electrical service such as disconnect, power outage or overhead/underground system work.

Answered: 906   Skipped: 0



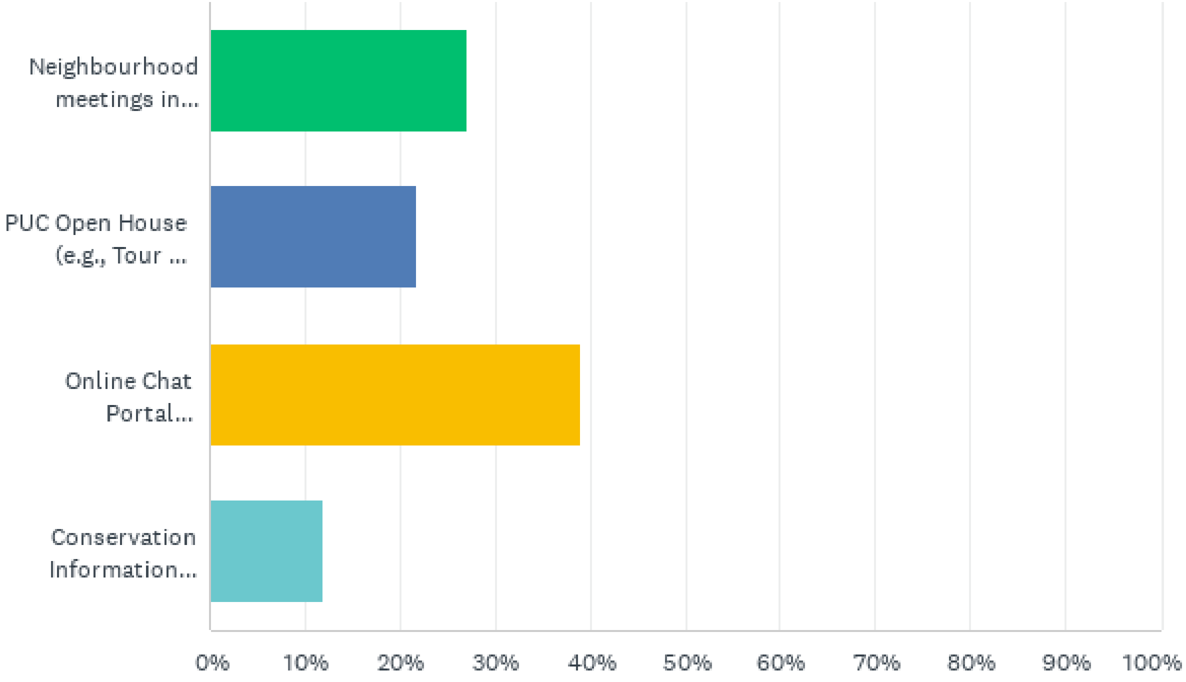
Q30: Please tell us how you felt about an experience with a PUC field representative that visited your home/business with regards to an electrical service such as disconnect, power outage or overhead/underground system work.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Very satisfied	37.20%	337
Somewhat satisfied	22.08%	200
Neither satisfied nor dissatisfied	4.42%	40
Somewhat dissatisfied	0.99%	9
Very dissatisfied	0.66%	6
Not Applicable	34.66%	314
TOTAL		906

Q31: As we move forward, PUC Distribution would like to improve communications and engagement with our community. Of the following ideas, what would you prefer to see?

Answered: 906   Skipped: 0



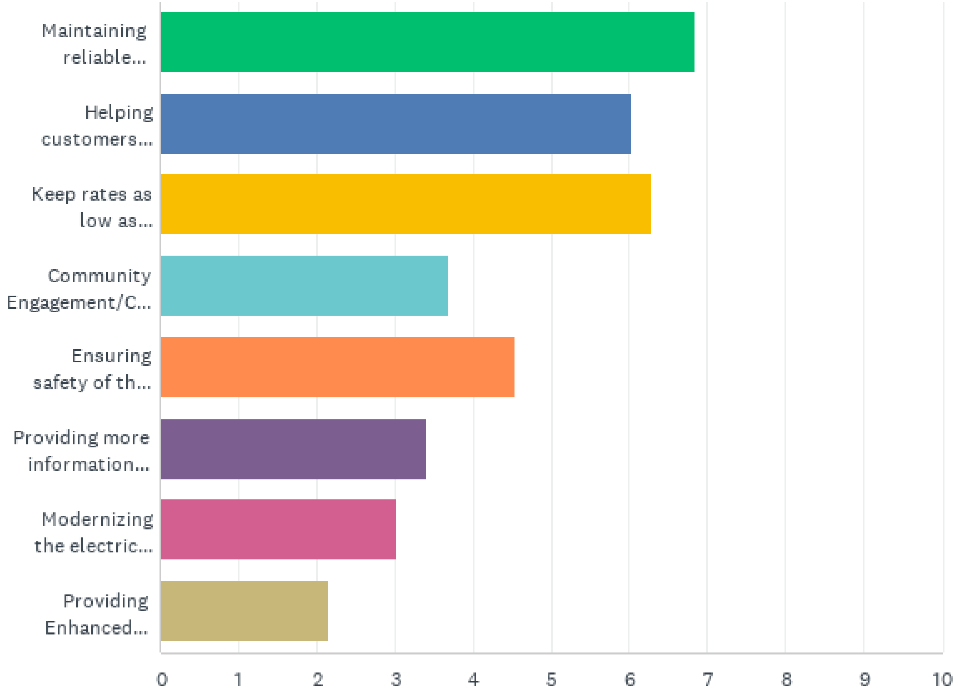
Q31: As we move forward, PUC Distribution would like to improve communications and engagement with our community. Of the following ideas, what would you prefer to see?

Answered: 906 Skipped: 0

ANSWER CHOICES	RESPONSES	
Neighbourhood meetings in advance of planned projects	27.15%	246
PUC Open House (e.g., Tour PUC facilities)	21.85%	198
Online Chat Portal (Connected to PUC website)	38.96%	353
Conservation Information Booths (e.g., Bushplane Days, RotaryFest)	12.03%	109
TOTAL		906

Q32: Among the following PUC priorities, place what you think each is in order of importance.

Answered: 906   Skipped: 0



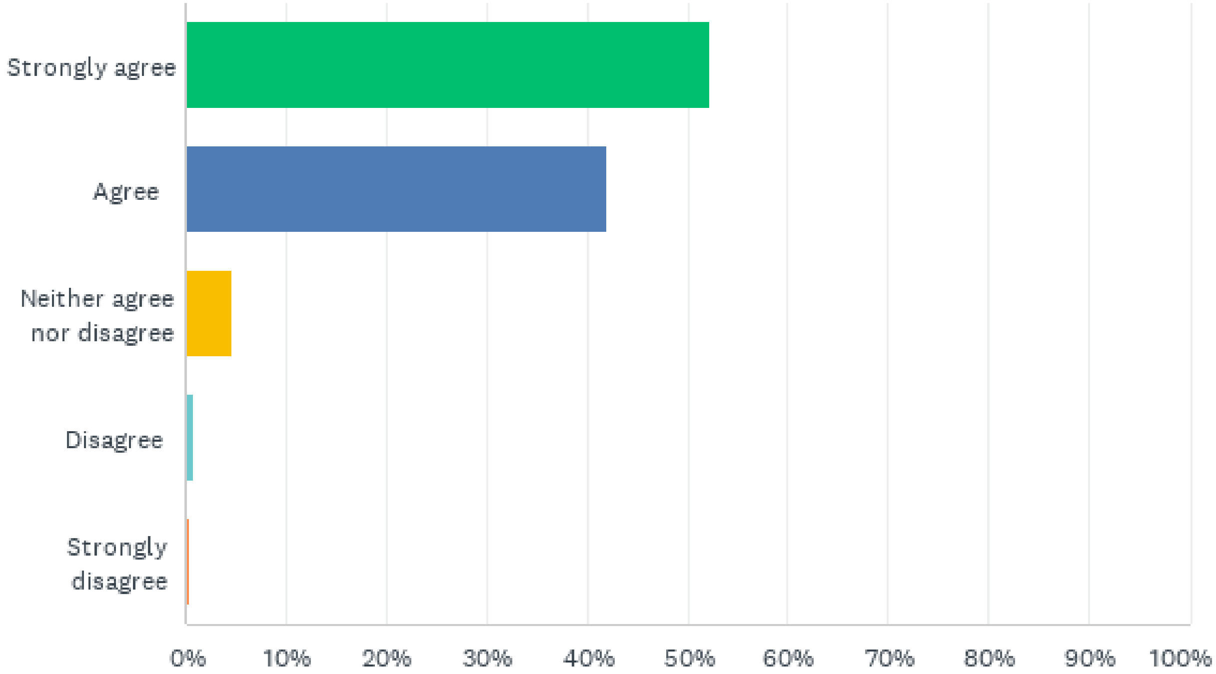
Q32: Among the following PUC priorities, place what you think each is in order of importance.

Answered: 906   Skipped: 0

	1	2	3	4	5	6	7	8	TOTAL	SCORE
Maintaining reliable electrical service (i.e. prevent/reduce power outages)	49.78% 451	21.30% 193	14.02% 127	5.74% 52	3.42% 31	2.21% 20	1.21% 11	2.32% 21	906	6.85
Helping customers reduce/manage consumption and by doing so reducing bills	14.57% 132	34.11% 309	21.41% 194	14.35% 130	6.95% 63	4.53% 41	2.21% 20	1.88% 17	906	6.03
Keep rates as low as practical while maintaining good quality electrical service	23.07% 209	24.39% 221	29.25% 265	13.13% 119	5.96% 54	2.21% 20	0.99% 9	0.99% 9	906	6.30
Community Engagement/Communication	1.43% 13	3.64% 33	9.38% 85	25.39% 230	16.00% 145	13.80% 125	12.14% 110	18.21% 165	906	3.68
Ensuring safety of the electrical system infrastructure	5.74% 52	8.61% 78	11.04% 100	17.77% 161	32.12% 291	16.56% 150	6.29% 57	1.88% 17	906	4.54
Providing more information during power outages	1.55% 14	2.87% 26	5.41% 49	10.71% 97	17.66% 160	37.31% 338	16.56% 150	7.95% 72	906	3.42
Modernizing the electrical system (e.g. electric vehicles, net-metering, etc.) to support the reduction of greenhouse gases and lessen climate change.	2.54% 23	3.31% 30	6.51% 59	8.06% 73	12.03% 109	12.47% 113	38.85% 352	16.23% 147	906	3.02
Providing Enhanced Customer Service (mobile app, customer connect, PUC website)	1.32% 12	1.77% 16	2.98% 27	4.86% 44	5.85% 53	10.93% 99	21.74% 197	50.55% 458	906	2.15

Q33: Please answer the following about PUC service:Provides consistent, reliable electricity.

Answered: 906   Skipped: 0



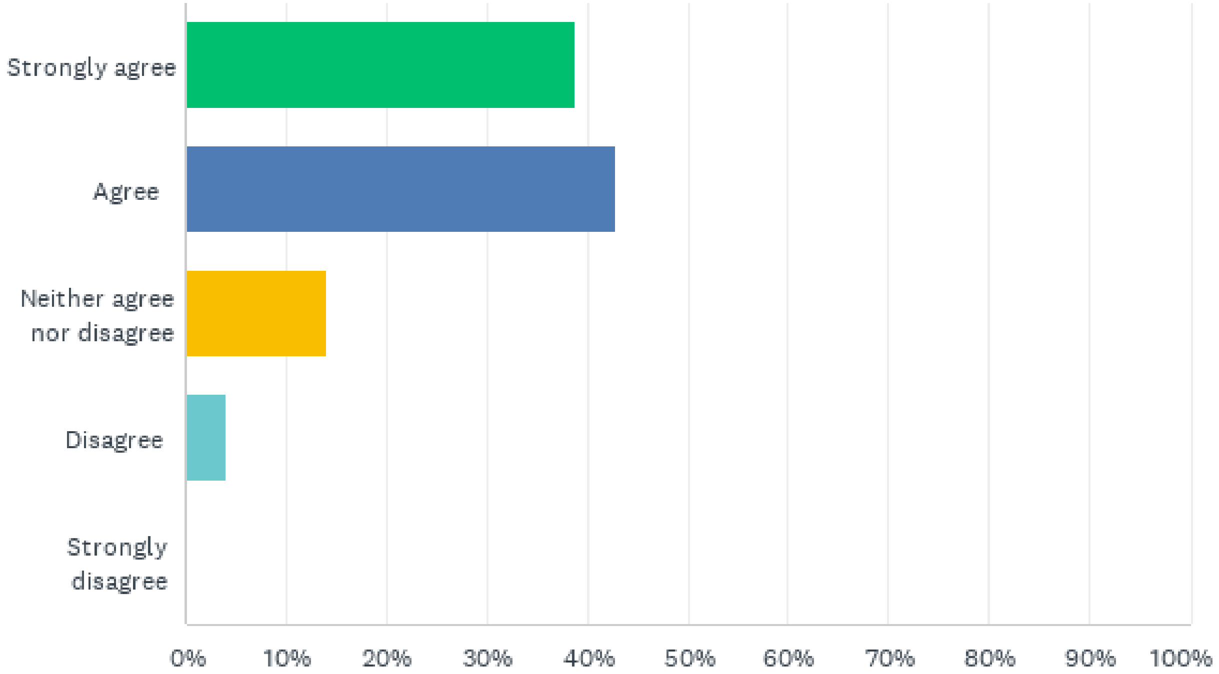
Q33: Please answer the following about PUC service:Provides consistent, reliable electricity.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Strongly agree	52.21%	473
Agree	41.94%	380
Neither agree nor disagree	4.75%	43
Disagree	0.77%	7
Strongly disagree	0.33%	3
TOTAL		906

Q34: Please answer the following about PUC service:Accurately bills its customers.

Answered: 906   Skipped: 0



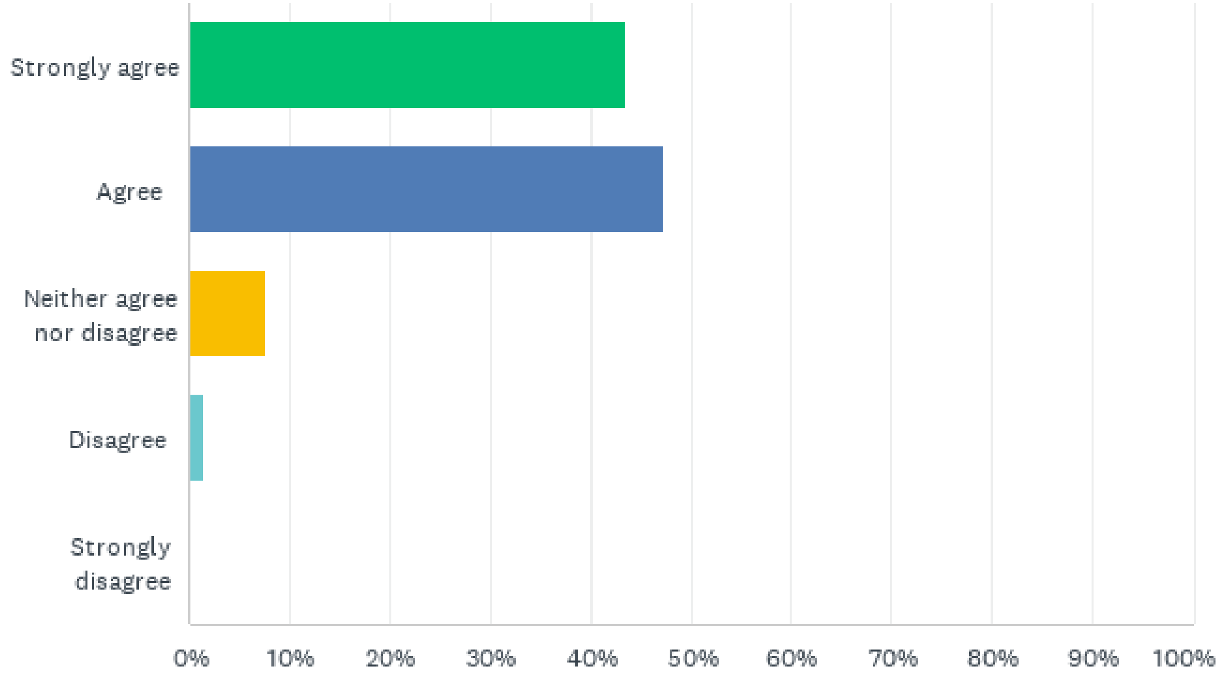
Q34: Please answer the following about PUC service:Accurately bills its customers.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Strongly agree	38.74%	351
Agree	42.83%	388
Neither agree nor disagree	14.13%	128
Disagree	4.08%	37
Strongly disagree	0.22%	2
TOTAL		906

Q35: Please answer the following about PUC service:Has a standard of reliability delivering electricity that meets your expectations.

Answered: 906   Skipped: 0



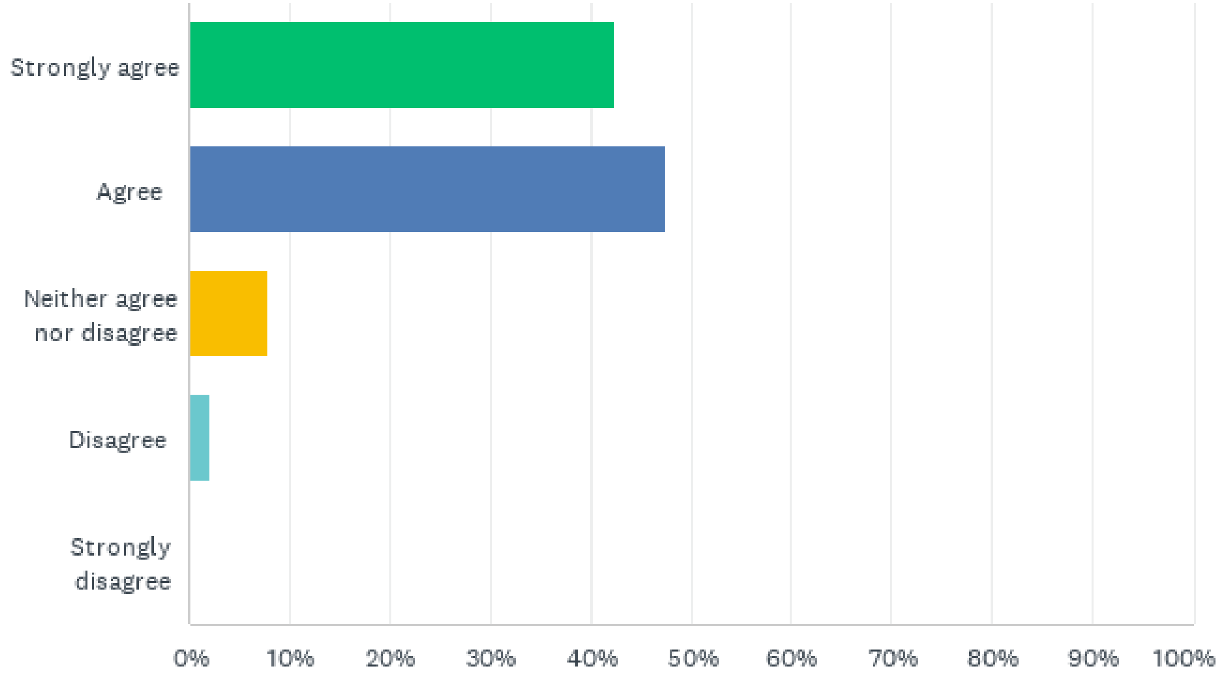
Q35: Please answer the following about PUC service:Has a standard of reliability delivering electricity that meets your expectations.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Strongly agree	43.49%	394
Agree	47.35%	429
Neither agree nor disagree	7.62%	69
Disagree	1.43%	13
Strongly disagree	0.11%	1
TOTAL		906

Q36: Please answer the following about PUC service:Quickly handles outages and restores power.

Answered: 906   Skipped: 0



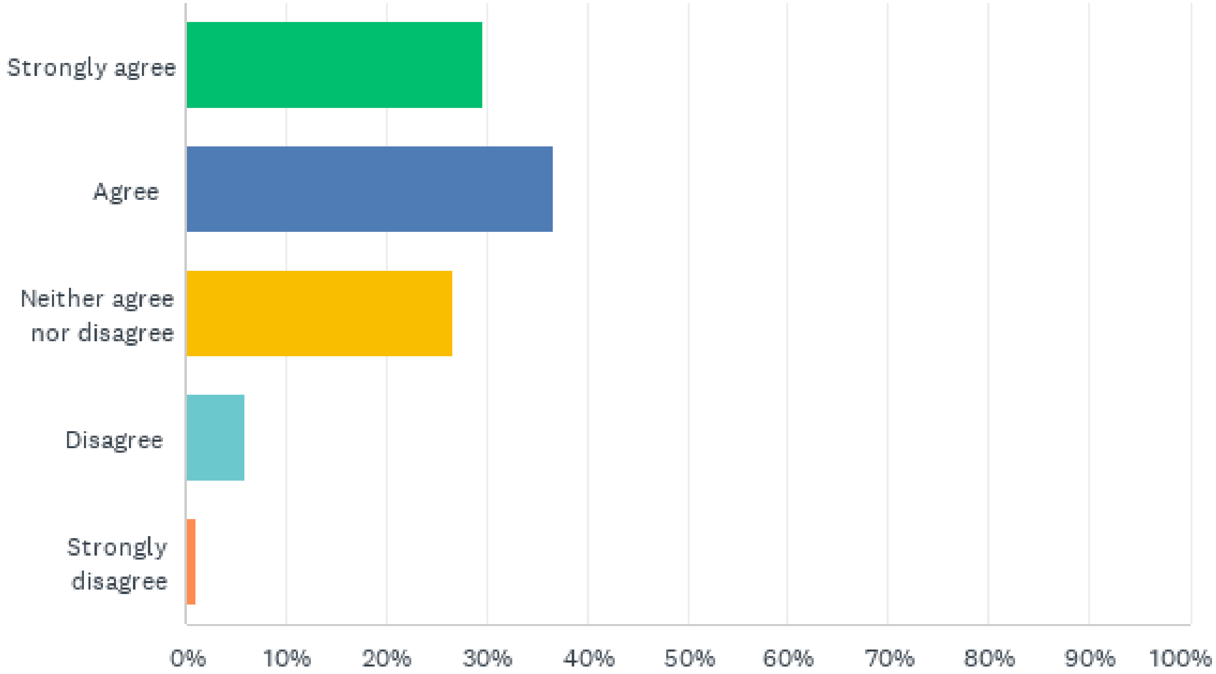
Q36: Please answer the following about PUC service:Quickly handles outages and restores power.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Strongly agree	42.38%	384
Agree	47.46%	430
Neither agree nor disagree	7.84%	71
Disagree	2.21%	20
Strongly disagree	0.11%	1
TOTAL		906

Q37: Please answer the following about PUC service:Communicates information on construction and investment activities.

Answered: 906   Skipped: 0



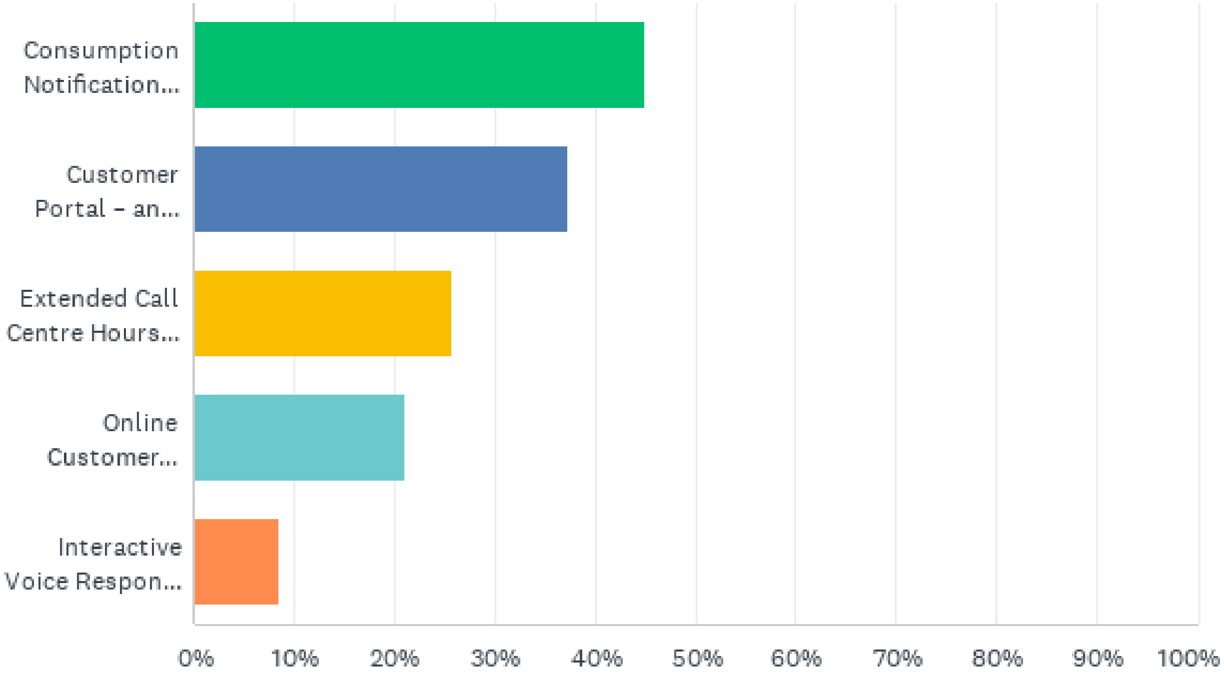
Q37: Please answer the following about PUC service:Communicates information on construction and investment activities.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Strongly agree	29.58%	268
Agree	36.64%	332
Neither agree nor disagree	26.71%	242
Disagree	5.96%	54
Strongly disagree	1.10%	10
TOTAL		906

Q38: In addition to the amount you currently pay on your electricity bill, would you be willing to pay for the following customer services? Please click box if you agree.

Answered: 906   Skipped: 0



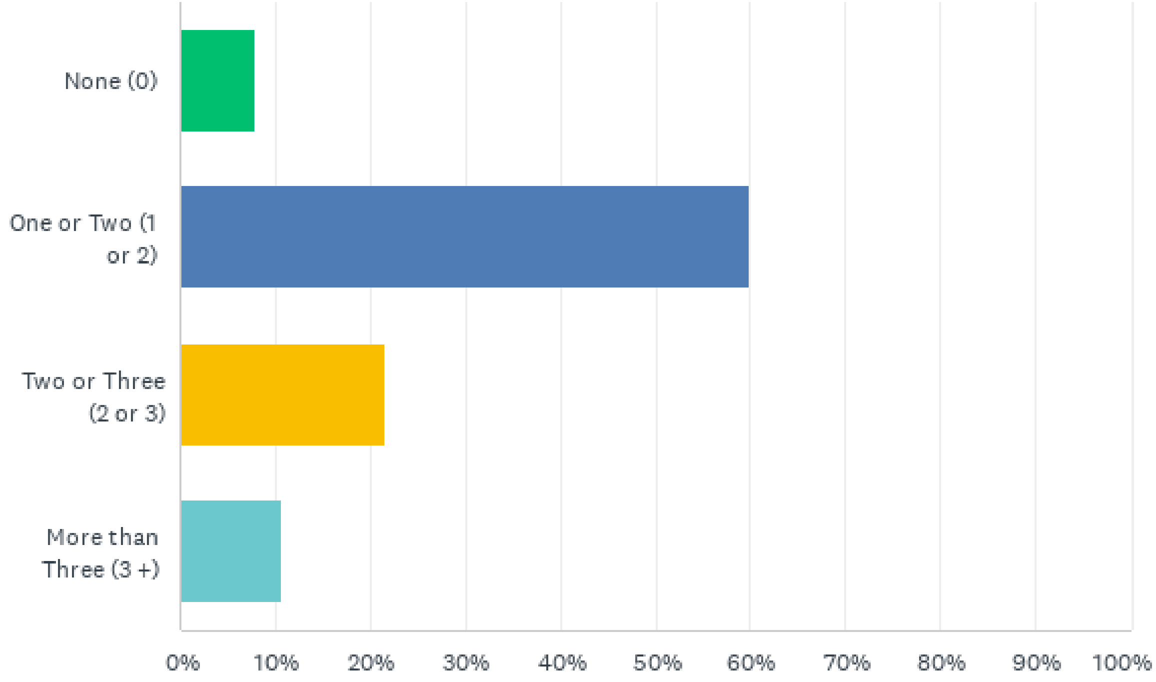
Q38: In addition to the amount you currently pay on your electricity bill, would you be willing to pay for the following customer services? Please click box if you agree.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Consumption Notification – getting notified via email, text alert when consumption hits certain level	44.92%	407
Customer Portal – an updated customer portal giving more detailed information on Billing, Usage, Outages, etc.	37.31%	338
Extended Call Centre Hours beyond M-F 9:00am – 4:30pm (i.e. 7 days a week 9:00am-9:00pm)	25.72%	233
Online Customer service – live chat with customer service representative during M-F 9:00am – 4:30pm	21.08%	191
Interactive Voice Response – telephone system that allows our computer system to interact with customer through a telephone keypad, providing account status, and outage updates	8.61%	78
Total Respondents: 906		

Q39: In the past year, how many power outages have you experienced.

Answered: 906   Skipped: 0



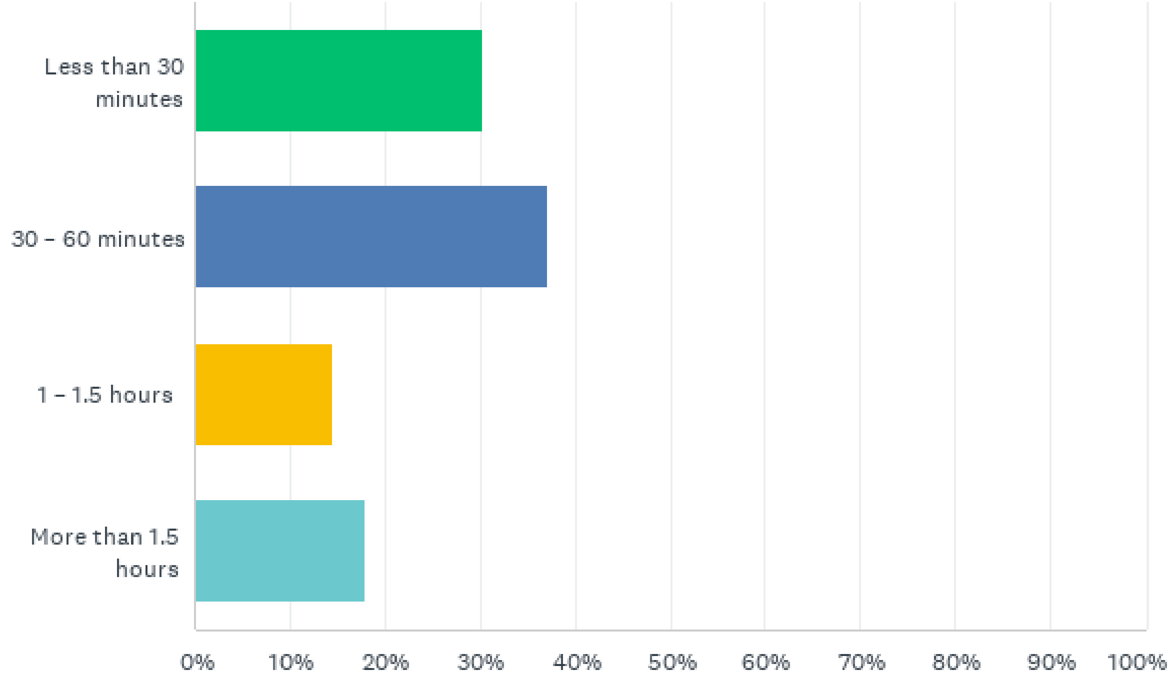
Q39: In the past year, how many power outages have you experienced.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
None (0)	7.95%	72
One or Two (1 or 2)	59.82%	542
Two or Three (2 or 3)	21.52%	195
More than Three (3 +)	10.71%	97
TOTAL		906

Q40: What was the longest power outage you had in the past year?

Answered: 906   Skipped: 0



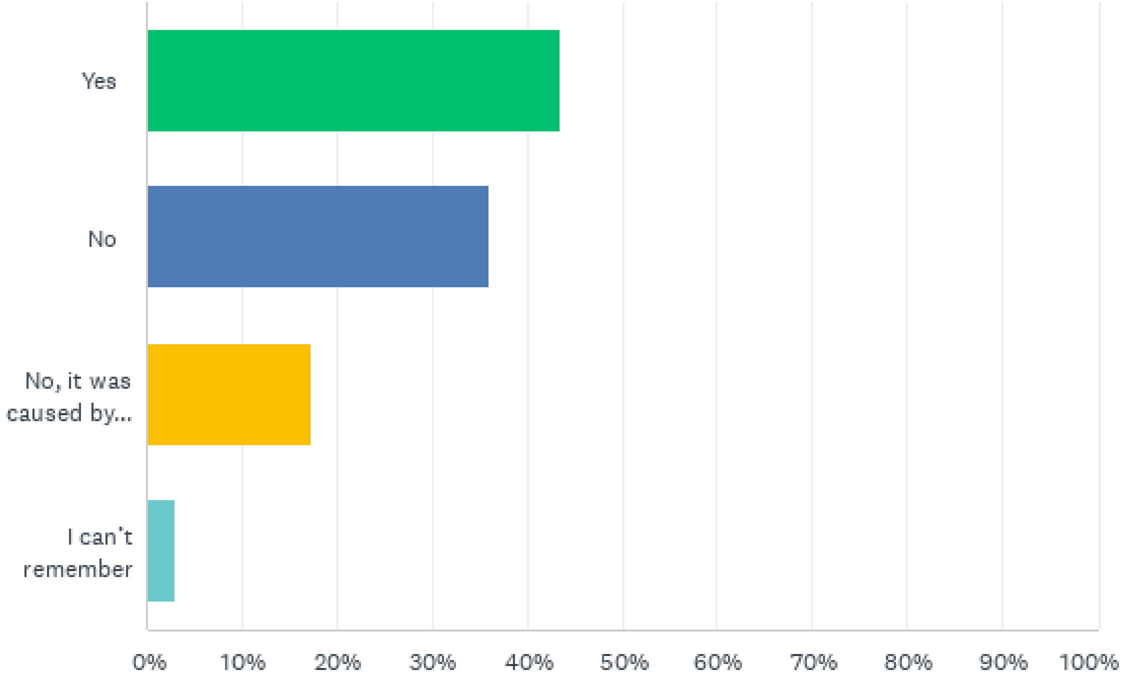
Q40: What was the longest power outage you had in the past year?

Answered: 906 Skipped: 0

ANSWER CHOICES	RESPONSES	
Less than 30 minutes	30.35%	275
30 – 60 minutes	37.20%	337
1 – 1.5 hours	14.57%	132
More than 1.5 hours	17.88%	162
TOTAL		906

Q41: Did you contact PUC about the power outage?

Answered: 906   Skipped: 0



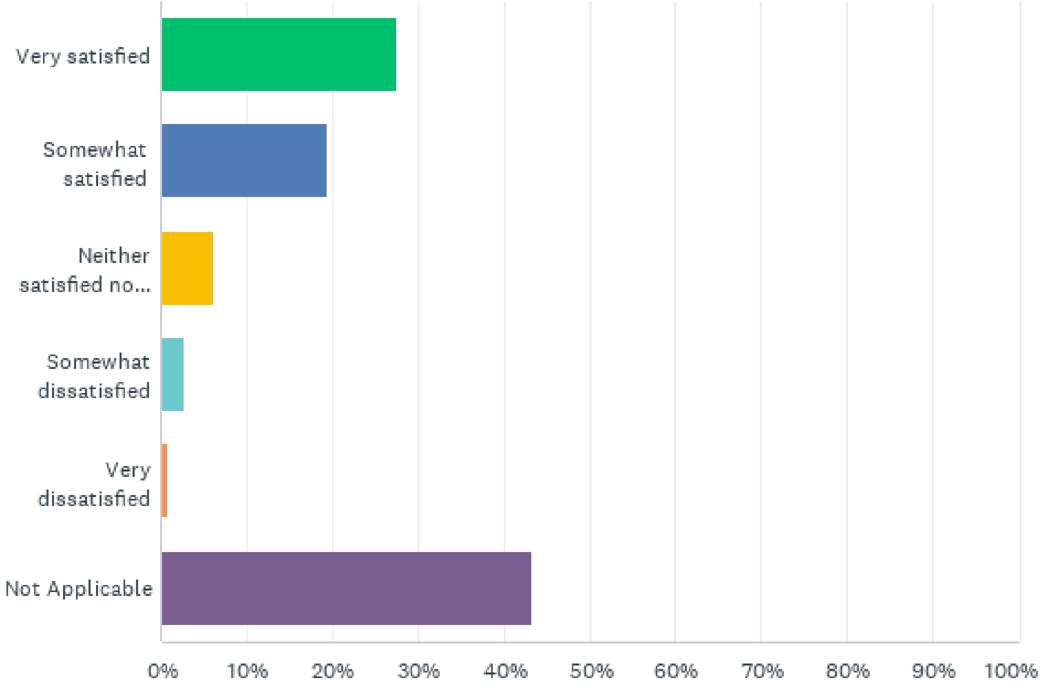
Q41: Did you contact PUC about the power outage?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Yes	43.49%	394
No	36.09%	327
No, it was caused by extreme/unusual weather	17.33%	157
I can't remember	3.09%	28
TOTAL		906

Q42: If you contacted PUC about a power outage, how satisfied were you with the way PUC responded to the outage?

Answered: 906   Skipped: 0



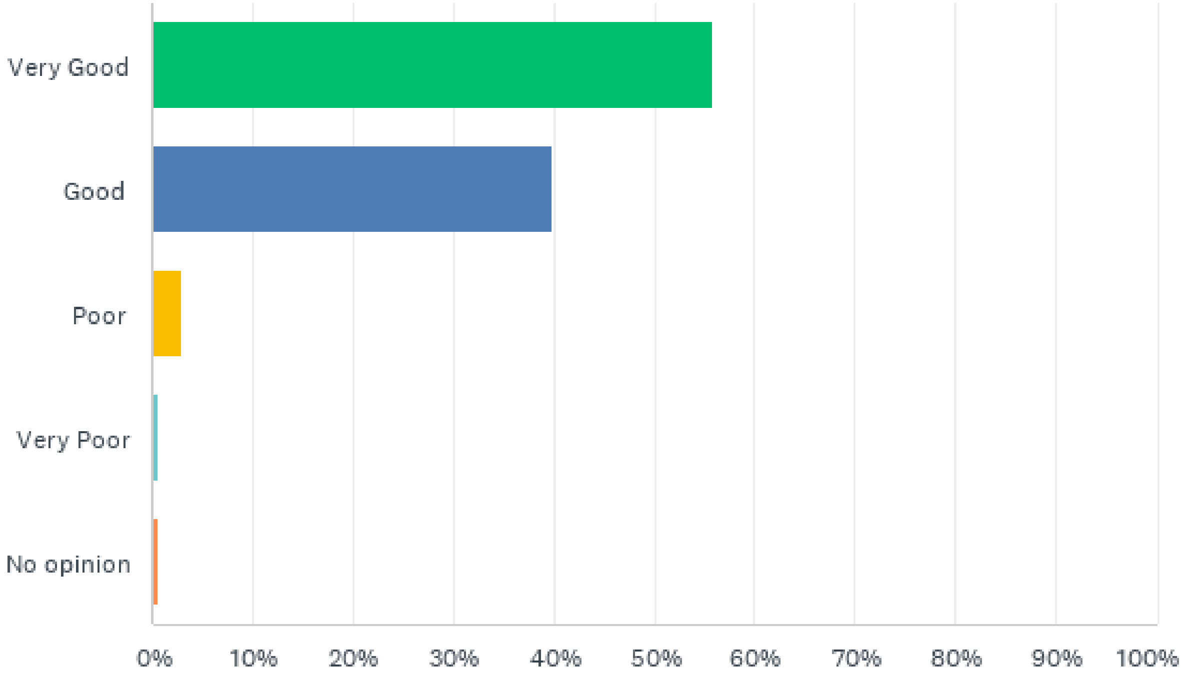
Q42: If you contacted PUC about a power outage, how satisfied were you with the way PUC responded to the outage?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Very satisfied	27.59%	250
Somewhat satisfied	19.43%	176
Neither satisfied nor dissatisfied	6.18%	56
Somewhat dissatisfied	2.76%	25
Very dissatisfied	0.77%	7
Not Applicable	43.27%	392
TOTAL		906

Q43: How do you feel the reliability of your power has been in past years?

Answered: 906   Skipped: 0



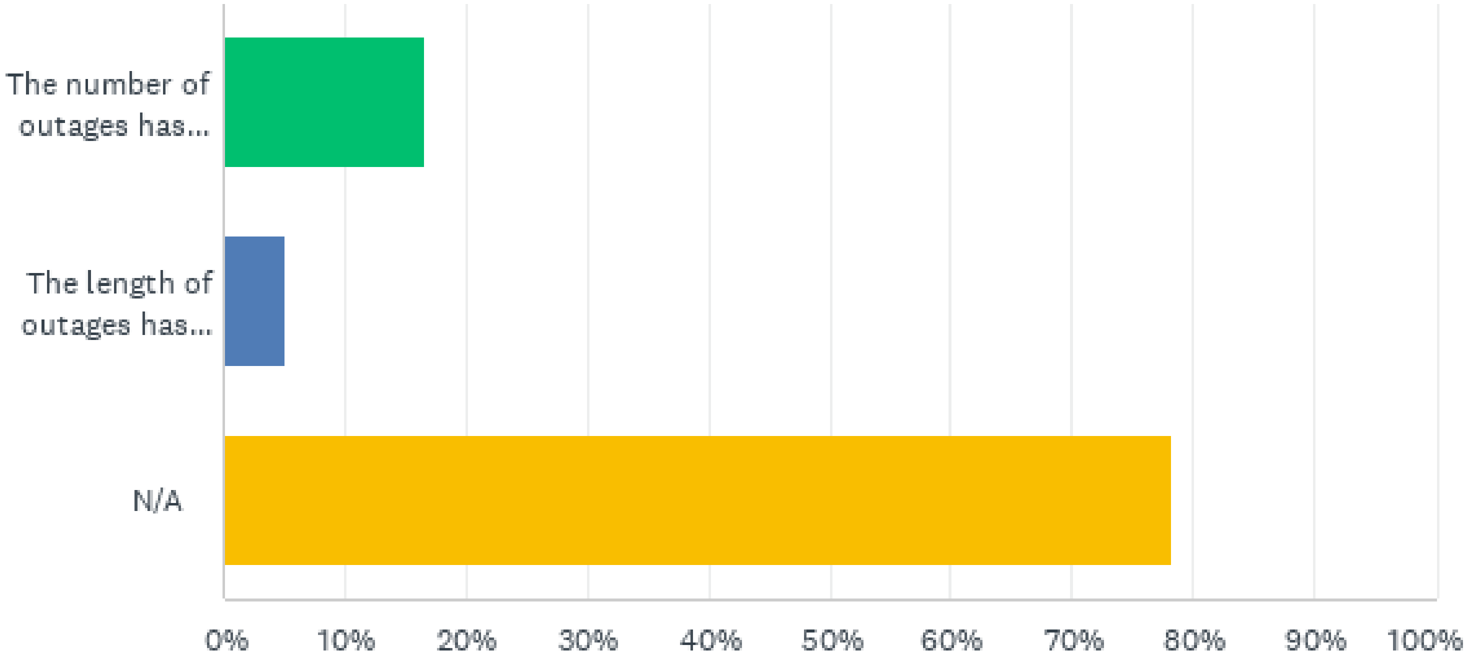
Q43: How do you feel the reliability of your power has been in past years?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
Very Good	55.85%	506
Good	39.96%	362
Poor	2.98%	27
Very Poor	0.55%	5
No opinion	0.66%	6
TOTAL		906

Q44: If you Indicated that the reliability of your power has been poor, please indicate a reason why. If you answer Very Good or Good to the previous question, please select N/A.

Answered: 906 Skipped: 0



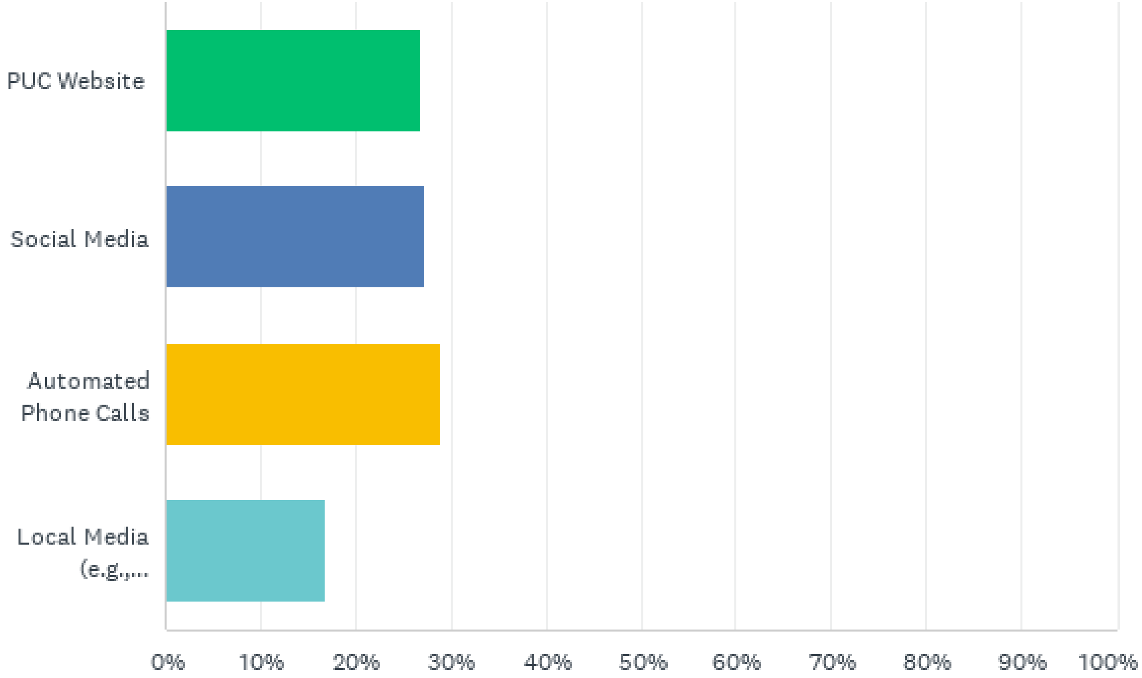
Q44: If you Indicated that the reliability of your power has been poor, please indicate a reason why. If you answer Very Good or Good to the previous question, please select N/A.

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
The number of outages has been high.	16.56%	150
The length of outages has been high.	5.19%	47
N/A	78.26%	709
TOTAL		906

Q45: Currently when there is a planned power outage, PUC provides door hangers, website updates and automated phone calls. How would you prefer PUC to communicate before, during and after planned or unplanned power outages?

Answered: 906 Skipped: 0



Q45: Currently when there is a planned power outage, PUC provides door hangers, website updates and automated phone calls. How would you prefer PUC to communicate before, during and after planned or unplanned power outages?

Answered: 906   Skipped: 0

ANSWER CHOICES	RESPONSES	
PUC Website	26.93%	244
Social Media	27.37%	248
Automated Phone Calls	28.92%	262
Local Media (e.g., Sootoday)	16.78%	152
TOTAL		906

APPENDIX M

Customer

Engagement Survey

Phase 2

PUC Distribution Customer Engagement Survey

Tuesday, July 12, 2022

816

Total Responses

Date Created: Wednesday, May 11, 2022

Complete Responses: 816

Introductory Page

Welcome to PUC's Customer Engagement Survey

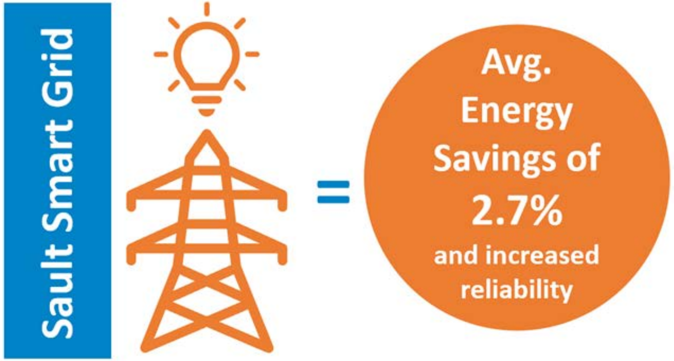
Thank you for participating in PUC Distribution (PUC)'s Customer Engagement Survey. This survey is part of our Cost of Service Application to the Ontario Energy Board (OEB), the province's regulator for the electricity industry. The OEB's Cost of Service application typically occurs every five years and determines what each local distribution company (LDC), like PUC, can charge for its distribution rate (also known as the delivery rate). We are looking to incorporate your much valued feedback into our future investment decisions at PUC.

Introductory Page

Through past engagement surveys, customers told us that reliability, affordability and reducing our carbon footprint were of high importance.

We listened.

Through new efficiencies and innovative projects like the Sault Smart Grid, PUC has worked hard to keep any increase on our portion of the bill as low as possible. Once operational in 2023, the Sault Smart Grid will result in a more reliable system *and* average energy savings of 2.7 per cent for our customers.



Introductory Page

Other commitments in the future, like electrifying our fleet, will result in lower overall maintenance and fuel costs, while reducing our carbon footprint.

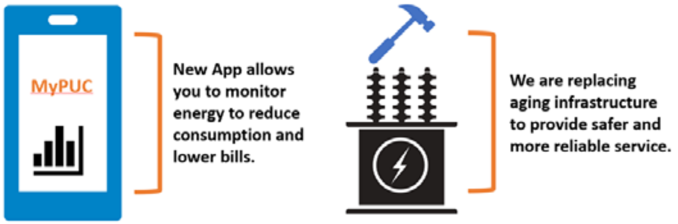
Introductory Page

Not only is PUC making efforts to help customers reduce their energy costs, we are making unprecedented investments in our customer service tools and aging infrastructure that will result in increased reliability today - and well into the future.

For example, our new MyPUC App now allows customers to track energy consumption in an easy and convenient way, resulting in better energy management and lower bills.

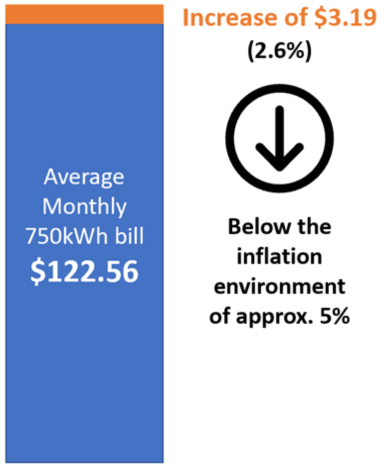
We are also renewing and replacing important assets like our aging Infrastructure, resulting in safer and more reliable service.

This is all part of PUC’s promise to “lead the way through innovation and compassion to deliver outstanding service every single day.”



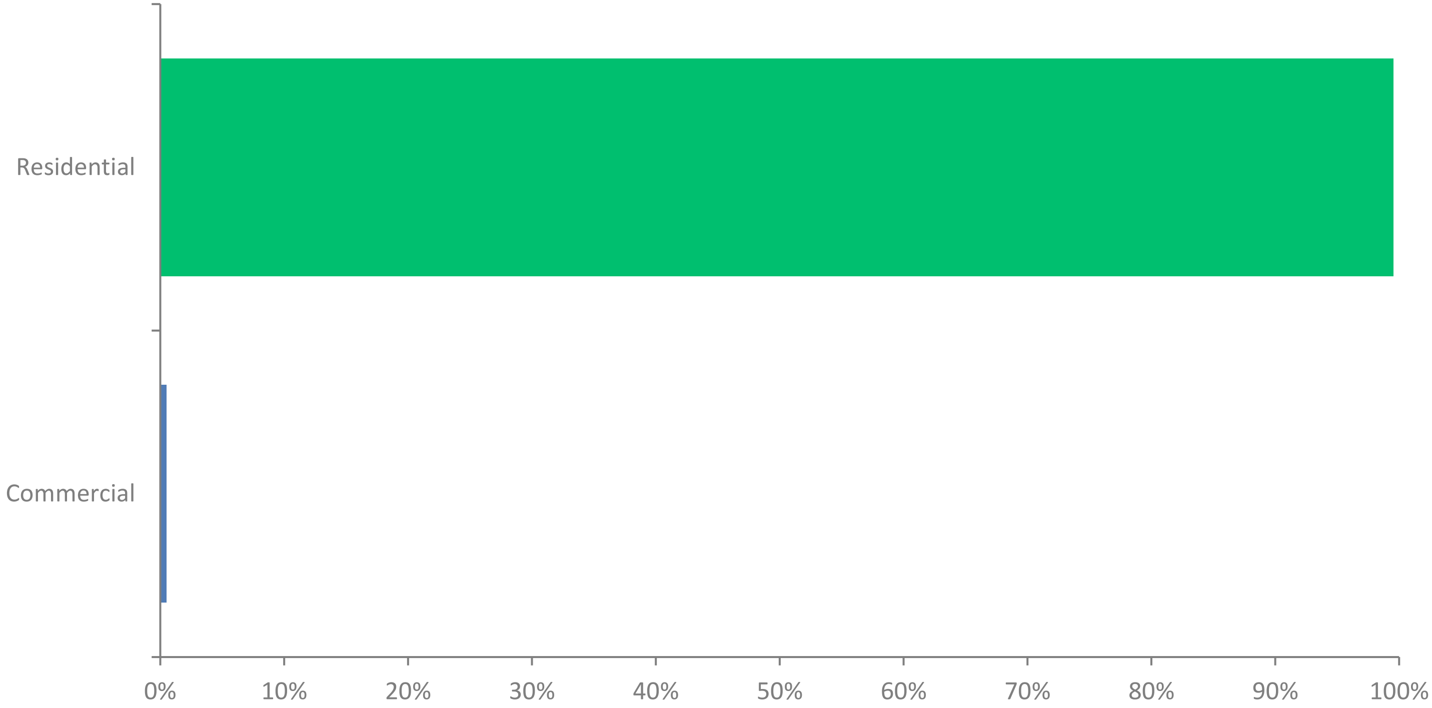
Introductory Page

If PUC's application to the OEB is approved, a current 750kWh avg. residential electricity bill of $122.56 would increase by approximately $3.19 per month or 2.6% - below the approx. 5% inflation environment - and comparable to a cup of coffee.



Q1: What type of customer best describes you?

Answered: 816 Skipped: 0



Powered by SurveyMonkey

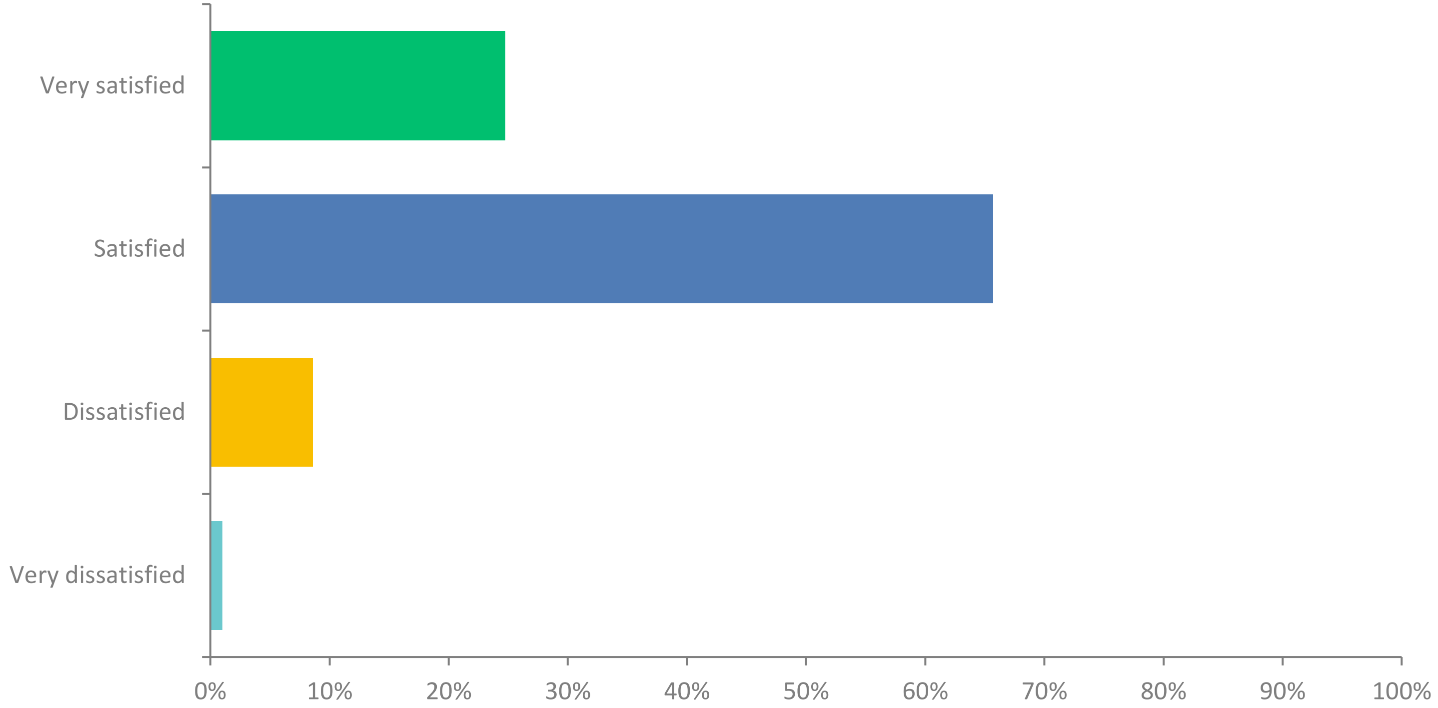
Q1: What type of customer best describes you?

Answered: 816 Skipped: 0

ANSWER CHOICES	RESPONSES	
Residential	99.51%	812
Commercial	0.49%	4
TOTAL		816

Q2: Considering all aspects of being a PUC customer, how would you rate your overall satisfaction with the company as your electrical services provider?

Answered: 816 Skipped: 0



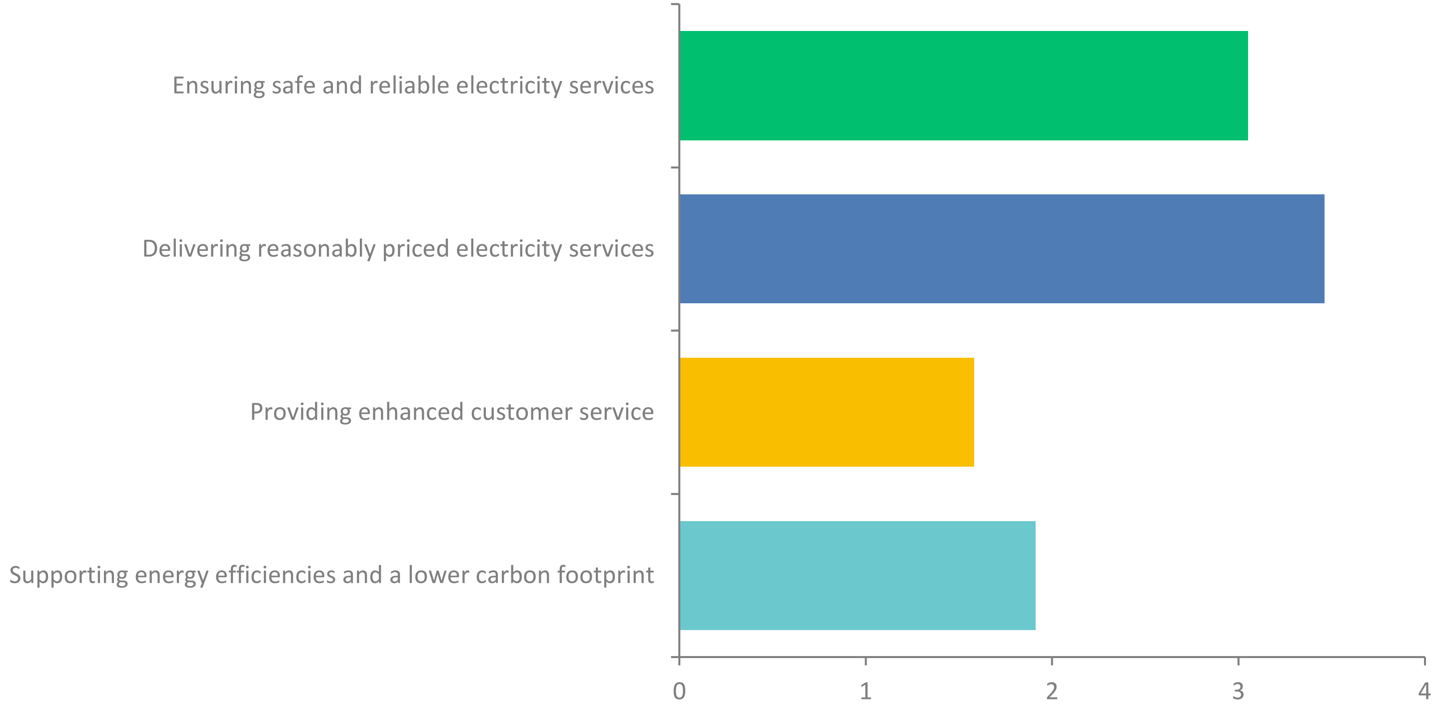
Q2: Considering all aspects of being a PUC customer, how would you rate your overall satisfaction with the company as your electrical services provider?

Answered: 816 Skipped: 0

ANSWER CHOICES	RESPONSES	
Very satisfied	24.75%	202
Satisfied	65.69%	536
Dissatisfied	8.58%	70
Very dissatisfied	0.98%	8
TOTAL		816

Q3: In an effort to better understand your current priorities, please rank the following, 1 being the most important:

Answered: 816 Skipped: 0



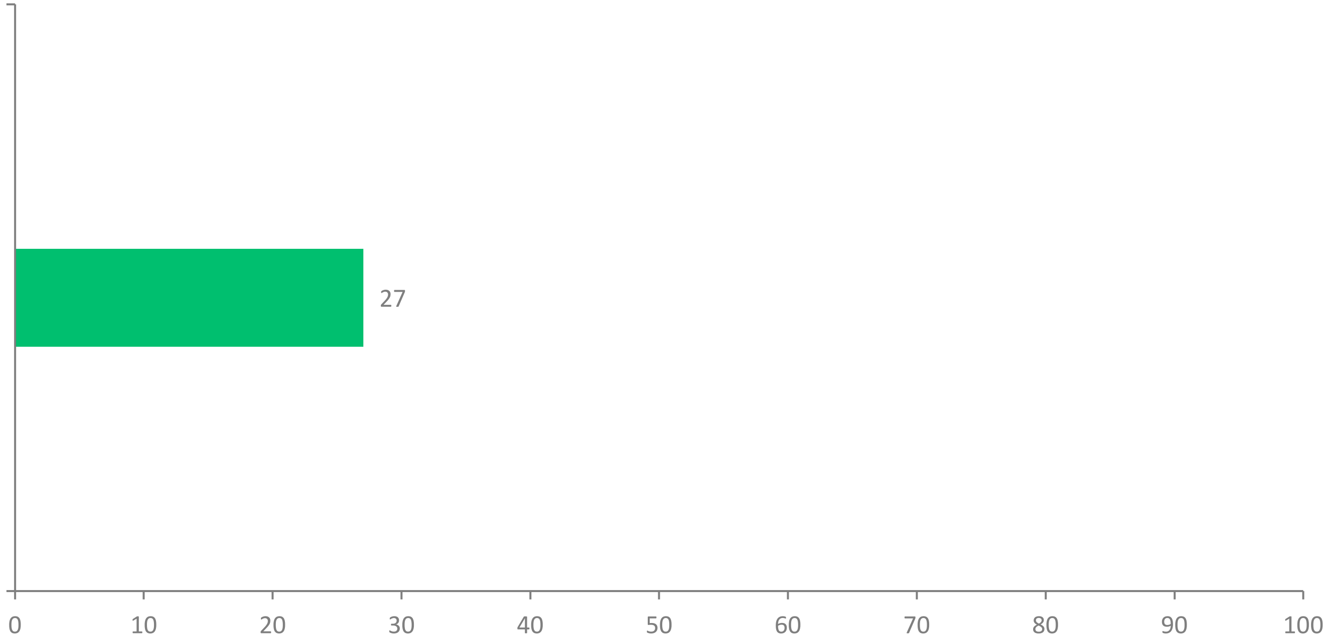
Q3: In an effort to better understand your current priorities, please rank the following, 1 being the most important:

Answered: 816 Skipped: 0

	1	2	3	4	TOTAL	WEIGHTED AVERAGE
Ensuring safe and reliable electricity services	32.84% 268	44.73% 365	17.28% 141	5.15% 42	816	3.05
Delivering reasonably priced electricity services	59.31% 484	30.02% 245	7.97% 65	2.70% 22	816	3.46
Providing enhanced customer service	2.08% 17	7.84% 64	36.15% 295	53.92% 440	816	1.58
Supporting energy efficiencies and a lower carbon footprint	5.76% 47	17.40% 142	38.60% 315	38.24% 312	816	1.91

Q4: PUC is committed to keeping our portion of your bill affordable, while providing safe and reliable electricity.As previously mentioned, cost increases and infrastructure investments will result in a rate increase for PUC Customers; estimates at this time are an approximate increase of $3.19/month on a $122.56 bill for an average residential customer.On a sliding scale, please let us know what is more important to you?

Answered: 816   Skipped: 0



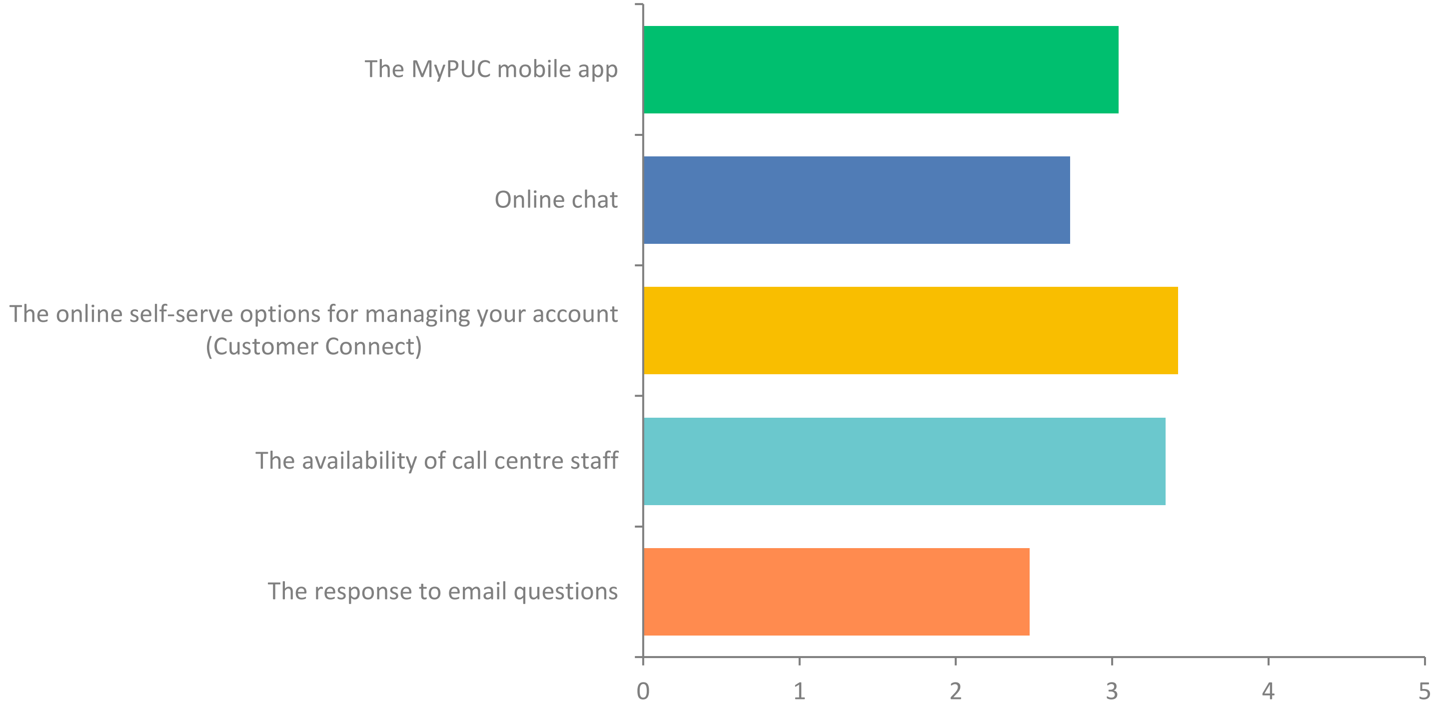
Q4: PUC is committed to keeping our portion of your bill affordable, while providing safe and reliable electricity.As previously mentioned, cost increases and infrastructure investments will result in a rate increase for PUC Customers; estimates at this time are an approximate increase of $3.19/month on a $122.56 bill for an average residential customer.On a sliding scale, please let us know what is more important to you?

Answered: 816 Skipped: 0

ANSWER CHOICES	AVERAGE NUMBER	TOTAL NUMBER	RESPONSES
	27	22,068	816

Q5: PUC has made it an ongoing strategic priority to improve our customer's experience. As it relates to the convenience of accessing customer services, please rank the following in order of importance.

Answered: 816 Skipped: 0



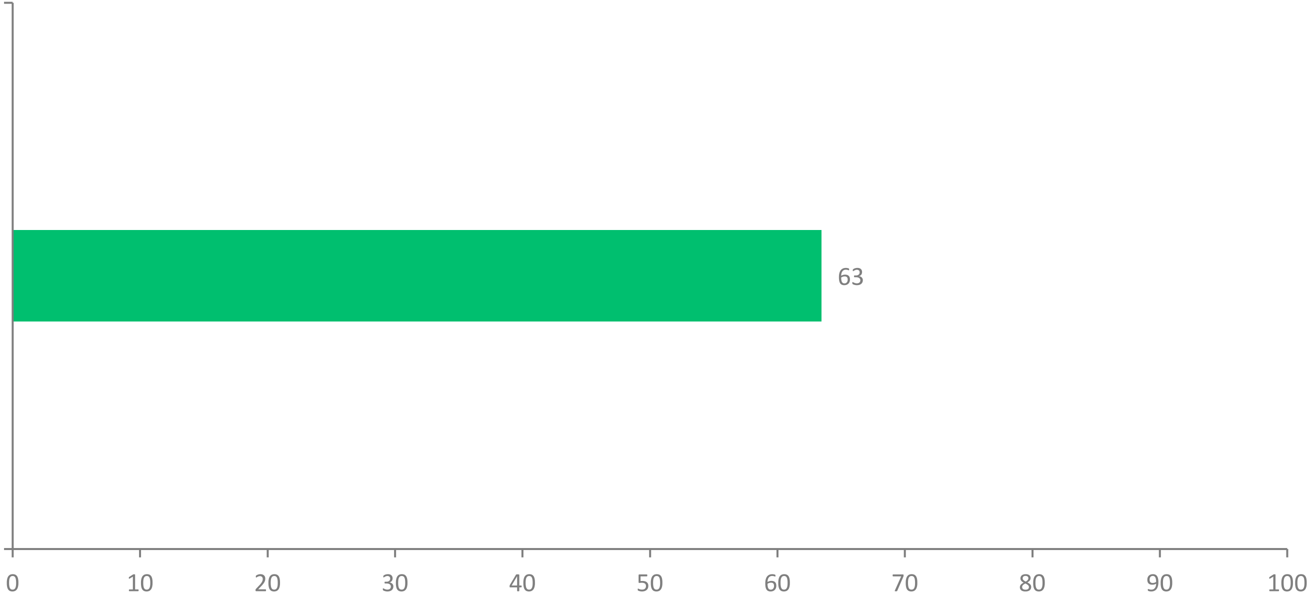
Q5: PUC has made it an ongoing strategic priority to improve our customer's experience. As it relates to the convenience of accessing customer services, please rank the following in order of importance.

Answered: 816 Skipped: 0

	1	2	3	4	5	TOTAL	WEIGHTED AVERAGE
The MyPUC mobile app	26.35% 215	18.01% 147	14.22% 116	16.30% 133	25.12% 205	816	3.04
Online chat	6.62% 54	21.69% 177	28.31% 231	24.51% 200	18.87% 154	816	2.73
The online self-serve options for managing your account (Customer Connect)	26.59% 217	23.04% 188	25.12% 205	16.54% 135	8.70% 71	816	3.42
The availability of call centre staff	33.95% 277	16.42% 134	14.83% 121	19.00% 155	15.81% 129	816	3.34
The response to email questions	6.50% 53	20.83% 170	17.52% 143	23.65% 193	31.50% 257	816	2.47

Q6: PUC communicates to its customers through a variety of methods including bill inserts, direct mail, social media, its website, MyPUC mobile app, newspapers and radio. Please rate the performance of PUC in communicating with its customers, 5 being excellent.

Answered: 816 Skipped: 0



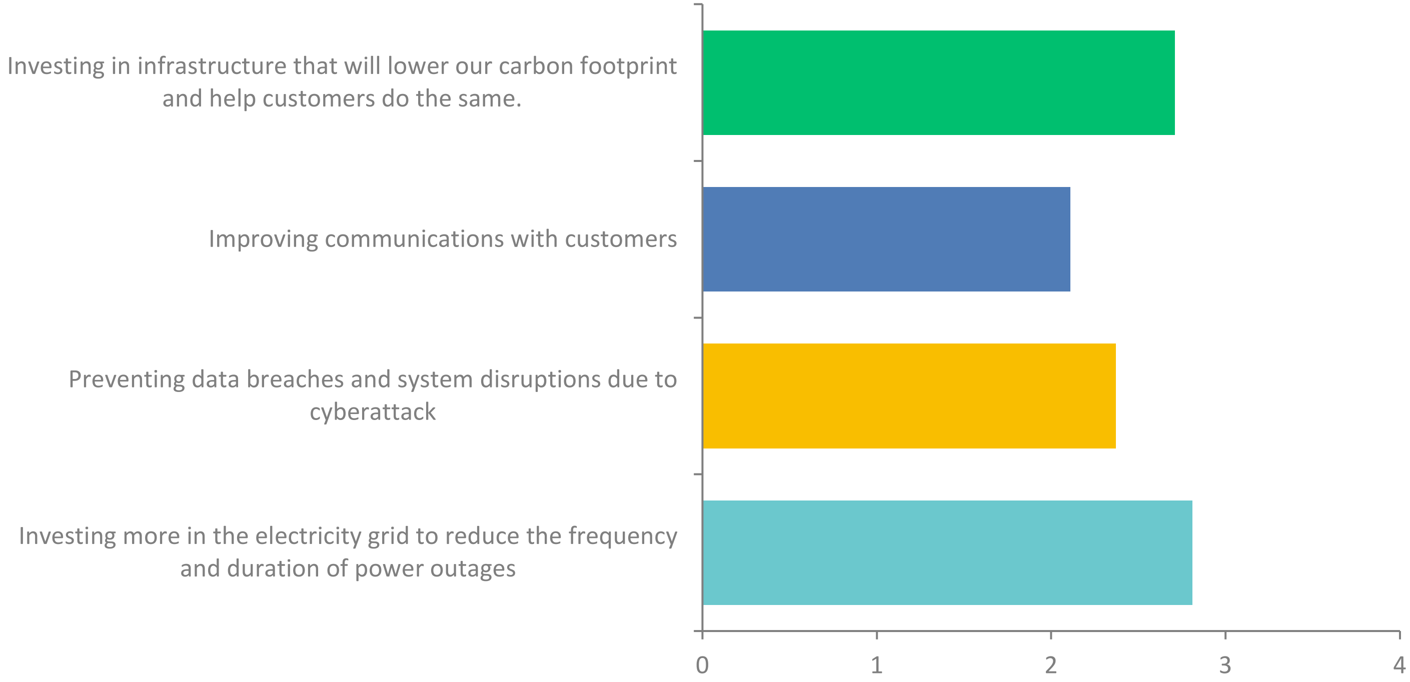
Q6: PUC communicates to its customers through a variety of methods including bill inserts, direct mail, social media, its website, MyPUC mobile app, newspapers and radio. Please rate the performance of PUC in communicating with its customers, 5 being excellent.

Answered: 816   Skipped: 0

ANSWER CHOICES	AVERAGE NUMBER	TOTAL NUMBER	RESPONSES
	63	51,776	816

Q7: On an ongoing basis, PUC assesses our strategic priorities to ensure we are meeting the needs of our customers. Please rank the following areas, 1 being the most important.

Answered: 816 Skipped: 0



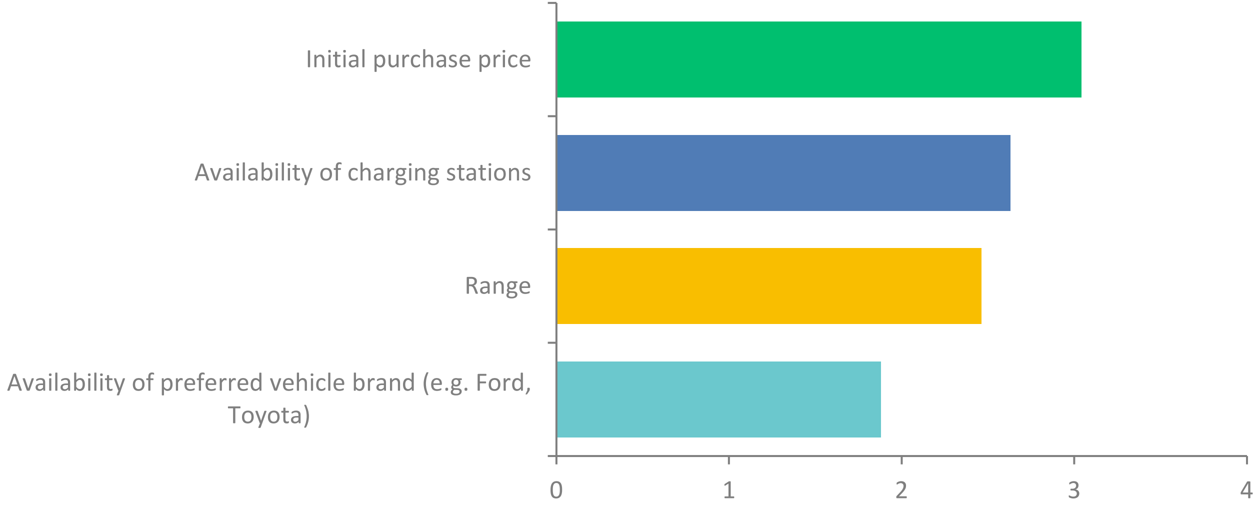
Q7: On an ongoing basis, PUC assesses our strategic priorities to ensure we are meeting the needs of our customers. Please rank the following areas, 1 being the most important.

Answered: 816 Skipped: 0

	1	2	3	4	TOTAL	WEIGHTED AVERAGE
Investing in infrastructure that will lower our carbon footprint and help customers do the same.	33.95% 277	23.77% 194	21.57% 176	20.71% 169	816	2.71
Improving communications with customers	13.97% 114	21.69% 177	25.98% 212	38.36% 313	816	2.11
Preventing data breaches and system disruptions due to cyberattack	17.28% 141	26.35% 215	32.72% 267	23.65% 193	816	2.37
Investing more in the electricity grid to reduce the frequency and duration of power outages	34.80% 284	28.19% 230	19.73% 161	17.28% 141	816	2.81

Q8: PUC is currently exploring opportunities that would promote use of Electric Vehicles within and around the community. This aligns with Canada's commitment to mandating all new light-duty vehicles sold be zero-emission by 2035, with an interim sales target of at least 50 percent by 2030.Below are a list of factors other people have told us are important when considering whether to buy an electric vehicle. Please rank each factor from 1-4, 1 being least important and 4 being the most important.

Answered: 816 Skipped: 0



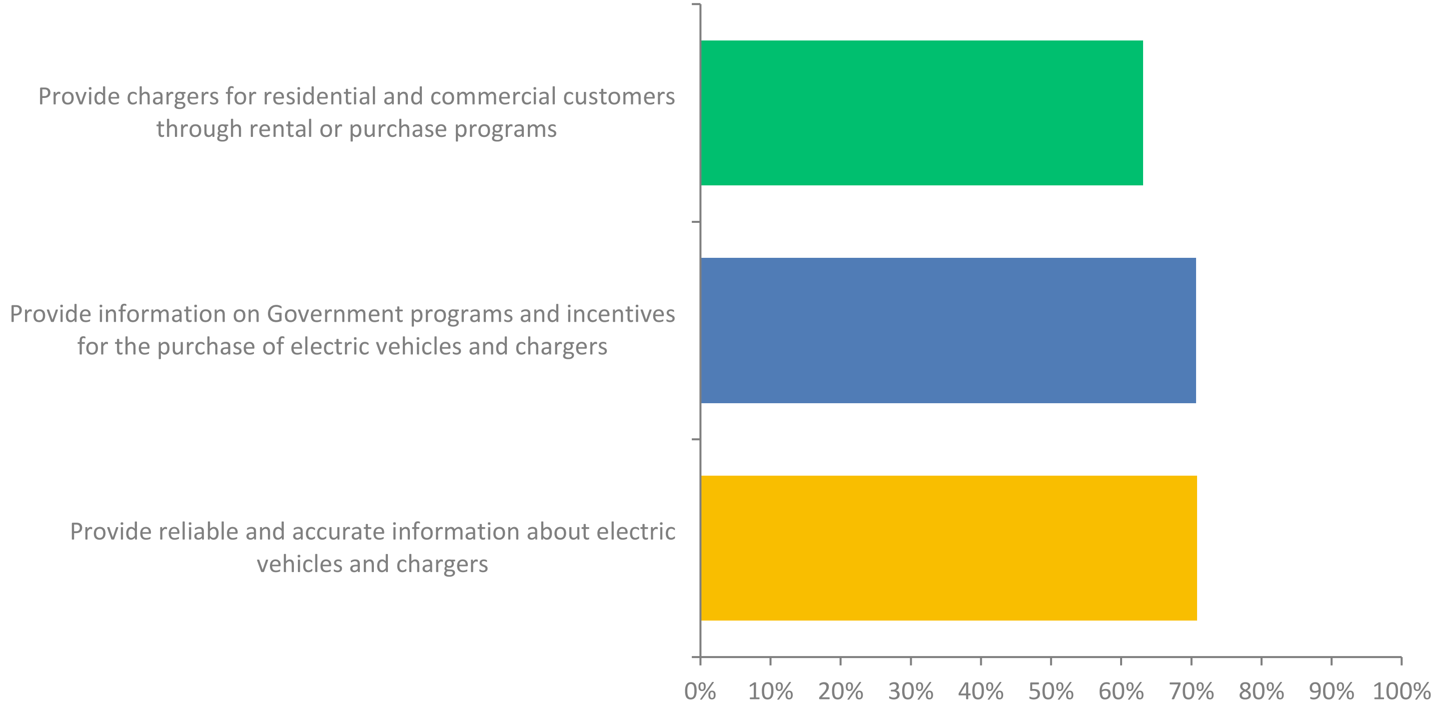
Q8: PUC is currently exploring opportunities that would promote use of Electric Vehicles within and around the community. This aligns with Canada's commitment to mandating all new light-duty vehicles sold be zero-emission by 2035, with an interim sales target of at least 50 percent by 2030.Below are a list of factors other people have told us are important when considering whether to buy an electric vehicle. Please rank each factor from 1-4, 1 being least important and 4 being the most important.

Answered: 816 Skipped: 0

	1	2	3	4	TOTAL	WEIGHTED AVERAGE
Initial purchase price	49.02% 400	21.57% 176	13.48% 110	15.93% 130	816	3.04
Availability of charging stations	17.89% 146	37.99% 310	32.97% 269	11.15% 91	816	2.63
Range	14.46% 118	30.88% 252	40.81% 333	13.85% 113	816	2.46
Availability of preferred vehicle brand (e.g. Ford, Toyota)	18.63% 152	9.56% 78	12.75% 104	59.07% 482	816	1.88

Q9: As a trusted community partner, how would you like to see PUC involved in the adoption of electric vehicles? Select all that apply:

Answered: 816 Skipped: 0



Q9: As a trusted community partner, how would you like to see PUC involved in the adoption of electric vehicles? Select all that apply:

Answered: 816 Skipped: 0

ANSWER CHOICES	RESPONSES	
Provide chargers for residential and commercial customers through rental or purchase programs	63.11%	515
Provide information on Government programs and incentives for the purchase of electric vehicles and chargers	70.71%	577
Provide reliable and accurate information about electric vehicles and chargers	70.83%	578
TOTAL		1670

EXHIBIT 2

RATE BASE

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

TABLE OF CONTENTS

LIST OF TABLES

EXHIBIT 2: RATE BASE

2.1 RATE BASE

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

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

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

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

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

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

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

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

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

Table 2-3: Rate Base Continuity Schedule

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

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

2.2 FIXED ASSET CONTINUITY STATEMENTS

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

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

Table 2-4: Depreciation Continuity Schedule

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

2.2.1 Rate Base Variance Analysis

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

Table 2-5: Rate Base Variance Summary

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

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

2.2.2 Variance Analysis On Gross Asset Additions

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

2018 Board Approved vs. 2018 Actual

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

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

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

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

ACCOUNT 1815 Transformer Station Equipment $169,484

- Transfer trip from Hydro One for line fault.

ACCOUNT 1830 Poles, Towers and Fixtures $156,952

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

ACCOUNT 1840 Underground Conduit $191,058

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

ACCOUNT 1850 Line Transformers ($283,179)

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

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

2018 Actual vs. 2019 Actual

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

Table 2-7: 2018 Actual vs. 2019 Actual

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

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

ACCOUNT 1808 Building & Fixtures $177,803

- LED lighting upgrades.
- HVAC upgrades.

ACCOUNT 1815 Transformer Station Equipment $233,949

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

ACCOUNT 1820 Distribution Station Equipment $226,273

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

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

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

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

ACCOUNT 1835 Overhead Conductors and Devices $646,542

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

ACCOUNT 1840 Underground Conduit $494,913

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

ACCOUNT 1845 Underground Conductors and Devices $314,478

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

ACCOUNT 1850 Line Transformers $898,402

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

ACCOUNT 1855 Services - $536,808

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

ACCOUNT 1860 Smart Meters $76,616

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

ACCOUNT 1980 System Supervisor Equipment $156,947

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

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

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

2019 Actual vs. 2020 Actual

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

Table 2-8: 2019 Actual vs. 2020 Actual

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

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

ACCOUNT 1815 Transformer Station Equipment $184,850

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

ACCOUNT 1820 Distribution Station Equipment $531,294

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

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

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

ACCOUNT 1835 Overhead Conductors and Devices $783,153

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

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

ACCOUNT 1845 Underground Conductors and Devices $554,440

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

ACCOUNT 1850 Line Transformers $953,608

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

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

ACCOUNT 1855 Services $392,402

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

ACCOUNT 1860 Meters $476,303

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

ACCOUNT 2440 Deferred Revenue ($658,166)

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

2020 Actual vs. 2021 Actual

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

Table 2-9: 2020 Actual vs. 2021 Actual

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

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

ACCOUNT 1808 Buildings and Fixtures $584,705

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

ACCOUNT 1820 Distribution Station Equipment $575,333

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

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

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

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

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

ACCOUNT 1835 Overhead Conductors and Devices $507,099

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

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

ACCOUNT 1840 Underground Conduit $183,281

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

ACCOUNT 1845 Underground Conductors and Devices $563,813

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

ACCOUNT 1850 Line Transformers $772,929

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

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

ACCOUNT 1855 Services $592,995

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

ACCOUNT 1860 Meters $216,522

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

ACCOUNT 2440 Deferred Revenue ($641,214)

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

2021 Actual vs. 2022 Bridge

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

Table 2-10: 2021 Actual vs. 2022 Bridge

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

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

ACCOUNT 1820 Distribution Station Equipment $30,000,462

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

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

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

- Various other immaterial items - $19,169.

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

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

ACCOUNT 1840 Underground Conduit $635,945

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

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

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

ACCOUNT 1850 Line Transformers $923,330

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

ACCOUNT 1855 Services $503,053

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

ACCOUNT 1860 Smart Meters $173,168

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

ACCOUNT 1980 System Supervisory Equipment $3,489,154

- SSG - $3,489,154

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

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

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

2022 Bridge vs. 2023 Test Year

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

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

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

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

ACCOUNT 1808 Buildings and Fixtures $577,035

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

ACCOUNT 1815 Transformer Station Equipment $275,973

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

ACCOUNT 1820 Distribution Station Equipment $2,780,627

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

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

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

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

ACCOUNT 1835 Overhead Conductors and Devices $811,945

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

ACCOUNT 1840 Underground Conduit $1,091,561

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

ACCOUNT 1845 Underground Conductors and Devices $174,831

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

ACCOUNT 1850 Line Transformers $1,302,668

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

ACCOUNT 1855 Services $517,876

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

ACCOUNT 1860 Smart Meters $206,980

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

ACCOUNT 1980 System Supervisory Equipment $387,684

- SSG - $387,684.

ACCOUNT 2440 Deferred Revenue ($592,500)

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

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

2.3.1 Breakdown by Function

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

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

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

<u>Table 2-12: Contributions</u>

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

<u>Summary of ICM Adjustments</u>

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

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

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

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

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

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

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

2.4 DEPRECIATION, AMORTIZATION and DEPLETION

2.4.1 Depreciation Policy

Amortization on capital assets is calculated as follows:

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

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

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

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

Table 2-14: 2018 Actual Depreciation

Accounting Standard	MIFRS
Year	**2018**

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

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

Table 2-15: 2019 Actual Depreciation

Accounting Standard	MIFRS
Year	2019

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

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

Table 2-16: 2020 Actual Depreciation

Accounting Standard MIFRS
Year 2020

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

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

Table 2-17: 2021 Actual Depreciation

Accounting Standard MIFRS
Year 2021

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

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

1
Table 2-18: 2022 Bridge Year Depreciation

Accounting Standard MIFRS
Year 2022

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

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

2

3

Table 2-19 2023: Test Year Depreciation

Accounting Standard MIFRS
Year 2023

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

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

Table 2-20: Gross Book Value of Assets

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

2.4.2 Asset Retirement Obligations ("AROs")

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

2.5 ALLOWANCE FOR WORKING CAPITAL

2.5.1 Allowance Factor Overview

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

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

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

2.5.2 Working Capital Allowance

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

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

Table 2-21: Working Capital Allowance

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

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

Table 2-22: Power Supply Expense 2023 Test Year

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

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

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

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

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

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

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

2.6 DISTRIBUTION SYSTEM PLAN

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

Table 2-23 Distribution System Plan Summary 2023-2027

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

2.7 POLICY OPTIONS FOR THE FUNDING OF CAPITAL

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

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

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

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

2.8.1 Substation 16 (EB-2019-0170)

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

Table 2-24: Variance Analysis ICM Costs

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

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

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

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

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

Table 2-25: Sub 16 Revenue Requirement Reconciliation

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

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

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

Table 2-25A: Sub 16 Revenue Requirement Reconciliation

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

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

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

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

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

Incremental Capital Adjustment **Rate Year:** 2020

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

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

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

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

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

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

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

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

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

Incremental Capital Adjustment | **Rate Year:** 2021

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

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

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

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

Amortization Expense			
Amortization Expense - Incremental	C	$ 97,366	S

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

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

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

Ontario Energy Board

Capital Module Applicable to ACM and ICM

PUC Distribution Inc.

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

Current Revenue Requirement

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

Eligible Incremental Capital for ACM/ICM Recovery

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

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

Return on Rate Base

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

Amortization Expense

Amortization Expense - Incremental	C	$	32,260	S

Grossed up Taxes/PILs

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

Incremental Revenue Requirement

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

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

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

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

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

Table 2-29: SSG ICM Reconciliation

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

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

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

Table 2-30: Revised Revenue Requirement SSG

Ontario Energy Board

Capital Module
Applicable to ACM and ICM

PUC Distribution Inc.

Incremental Capital Adjustment **Rate Year:** 2022

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

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

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

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

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

Amortization Expense				
Amortization Expense - Incremental	C	$	300,224	S

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

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

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

2.9 CAPITALIZATION POLICY

2.9.1 Capitalization Policy - IFRS

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

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

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

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

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

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

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

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

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

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

Table 2-32: Materiality Limits

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

2.9.2 Capitalization of Overhead

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

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

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

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

Overview

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

History

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

2.10.1 Applications for REG Greater than 10kW

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

Table 2-33: Applications for REG over 10kW

PUC Applications from Renewable Generators Over 10kW

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

2.10.2 Applications for REG 10kW or less

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

System Capacity to Support REG

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

Table 2-34: PUC Available Capacity

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

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

Proposed Plan and Investments to Support REG

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

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

APPENDIX A

Fixed Asset

Continuity Schedule

Board Appendix 2-BA

Accounting Standard	MIFRS
Year	**2018**

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

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

Accounting Standard	MIFRS
Year	**2019**

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

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

Accounting Standard	MIFRS
Year	**2020**

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

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

Accounting Standard MIFRS
Year 2021

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

	Transportation	Transportation	
	Stores Equipment	Stores Equipment	
	Deferred Revenue	Deferred Revenue	-$ 140,229

Less: *Fully Allocated Depreciation*

Net Depreciation **$ 3,842,226**

Accounting Standard	MIFRS
Year	**2022**

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

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

Accounting Standard MIFRS
Year 2023

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

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

APPENDIX B

Depreciation and

Amortization Expense

Board Appendix 2-C

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

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

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

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

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

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

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

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

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

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

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

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

APPENDIX C

PUC Distribution Inc.

Distribution System

Plan ("DSP")

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

PUC Distribution Inc.

Distribution System Plan

2023 Cost of Service Application

Historical Period:

2018 – 2022

Forecast Period:

2023 – 2027

August 31, 2022

CONTENTS

LIST OF APPENDICES

LIST OF TABLES

LIST OF FIGURES

ACRONYMS

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

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

5.2 Distribution System Plan

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

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

PUC Distribution Inc. (PUC) has prepared this Distribution System Plan (DSP) in accordance with the Ontario Energy Board's (OEB's) Chapter 5 – Distribution System Plan Filing Requirements for Electricity Distribution Rate Applications, dated April 18, 2022 (Filing Requirements) as part of its 2023 Cost of Service Application (the Application).

The DSP is a stand-alone document that is filed in support of PUC's Application. The DSP's duration is a minimum of ten years in total, comprising of a historical period and a forecast period. The DSP covers the historical period of 2018 to 2022, with 2022 being the bridge year, and a forecast period of 2023 to 2027, with 2023 being the Test Year.

The DSP contents are organized into three major sections:

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

The materiality threshold for PUC is $135,000 and detailed descriptions of specific projects and programs exceeding the materiality threshold are provided in Section 5.4.2.1 and Appendix A. Other pertinent information relevant to this DSP is included in the Appendices.

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

5.2.1 Distribution System Plan Overview

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

5.2.1.1 Description of the Utility Company

5.2.1.1.1 Service Area and Customers

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

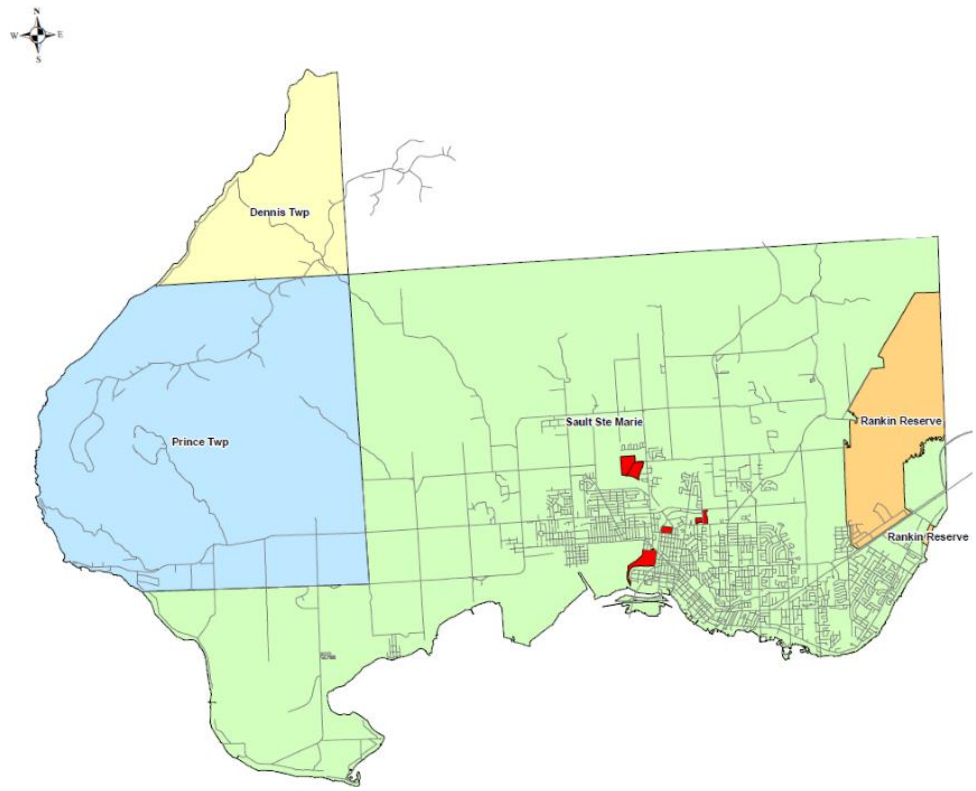


Figure 5.2-1: Map of Distribution Service Territory[1]

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

5.2.1.1.2 Mission, Vision, Values, and Goals

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

<u>Mission</u>

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

<u>Vision</u>

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

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

Values

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

Corporate Strategic Goals

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

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

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

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

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

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

5.2.1.2 The Sault Smart Grid Project

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

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

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

5.2.1.3 Capital Investment Highlights

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

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

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

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

[1] 0 months of actual expenditures included in 2022

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

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

5.2.1.3.1 System Access

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

5.2.1.3.2 System Renewal

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

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

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

5.2.1.3.3 System Service

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

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

5.2.1.3.4 General Plant

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

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

5.2.1.3.5 Contributed Capital

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

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

5.2.1.4 Key Changes since Last DSP Filing

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

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

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

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

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

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

5.2.1.5 DSP Objectives

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

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

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

This DSP covers a planning horizon of five years starting in the 2023 Test Year. Employing this long-term approach requires PUC to consider future customer needs and any required changes to its distribution system in advance. This approach enhances PUC's ability to plan ahead and respond to evolving customer needs in a timely manner, while managing and leveling the impacts of expenditures on consumer rates to maintain affordability of its service. The DSP recognizes PUC's responsibilities and commitments to provide customers with reliable service by ensuring that its asset management activities focus on the performance outcomes established in the OEB's Renewed Regulatory Framework (RRF) for electricity:

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

5.2.2 Coordinated Planning with Third Parties

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

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

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

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

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

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

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

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

5.2.2.1 Customer Engagement

Purpose of Consultation

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

Initiation and Participation

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

Nature and Timing of Final Deliverables

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

Brief Description of Customer Engagements

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

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

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

UtilityPULSE Customer Satisfaction surveys:

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

Customer Pulse surveys:

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

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

Cost of Service-related surveys:

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

Consultations Impact on this DSP

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

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

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

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

5.2.2.2 Municipal Government, Developers and Utility Consultations

Purpose of Consultation

PUC interacts with the City of Sault Ste. Marie administration to coordinate infrastructure planning within its service territory, so that new connections to customers can be connected in a timely manner and projects involving line relocates to facilitate road reconstruction projects can be planned. PUC staff attend formal meetings annually with the City and other municipal stakeholders such as developers and local utilities (water, gas, oil), to review budgets and work plans for the coming year and the next five years. Other ad-hoc coordination sessions occur on an as needed basis with the City and development stakeholders to look for synergies on specific projects and initiatives such as subdivision, commercial, and institutional developments.

Initiation and Participation

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

Nature and Timing of Final Deliverables

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

Brief Description of the Consultation

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

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

Consultations Impact on this DSP

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

5.2.2.3 Regional Planning Process

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

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

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

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

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

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

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

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

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

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

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

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

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

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

5.2.2.4 Telecommunication Entities

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

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

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

Consultations

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

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

Table 5.2-4: Summary of Consultations

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

Result of Consultations

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

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

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

Consultation Effects on the DSP

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

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

5.2.2.5 CDM Engagements

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

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

5.2.2.6 Renewable Energy Generation

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

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

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

5.2.2.7 Green Button

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

Green Button is part of the Ontario government's commitment to give consumers more choice when it comes to their energy use and will enable easy, quick, and secure access to their consumption data through smartphone or computer applications so they can find customized tips to reduce energy use or switch electricity price plans to save money.

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

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Distribution System Plan

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

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

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

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

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

Table 5.2-5: DSP Performance Measures

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

[1] Targets shown are for year 2021.

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

SAIDI & SAIFI in 2019, 2020 and 2021

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

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

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

Number of General Public Incidents in 2018, 2019 and 2020

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

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

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

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

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

Liquidity

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

5.2.3.2 Service Quality and Reliability

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

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

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

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

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

5.2.3.2.1 Service Quality Requirements

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

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

Table 5.2-6: Historical Service Quality Metrics

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

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

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

5.2.3.2.2 Reliability Requirements

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

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

Loss of Supply (LOS) outages occur due to problems associated with assets owned by another party other than PUC or the bulk electricity supply system. "Major Events" are defined by OEB as the events beyond the control of the distributor and are unforeseeable, unpredictable; unpreventable; or unavoidable. Such events disrupt normal business operation and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers. Major Event Days (MED) are calculated using the IEEE Std 1366-2012 methodology. MEDs are confirmed by assessing whether interruption was beyond the control of PUC (i.e., force majeure or LOS) and whether the interruption was unforeseeable, unpredictable, unpreventable, or unavoidable.

The fixed performance baseline targets for SAIDI and SAIFI over the historical period is based on the average performance over the 2013-2017 period, excluding LOS and Major Events. This corresponds to a fixed target of 1.38 for SAIDI and 1.33 for SAIFI. No targets are set for CAIDI.

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

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

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

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

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

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

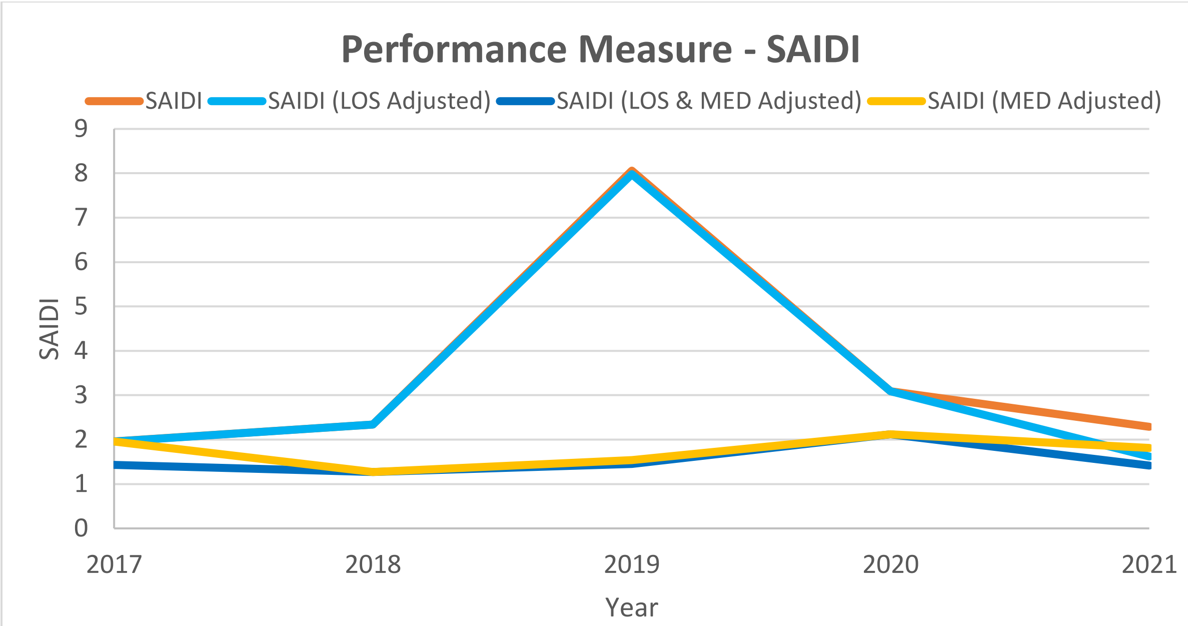


Figure 5.2-1: Performance Measure – SAIDI

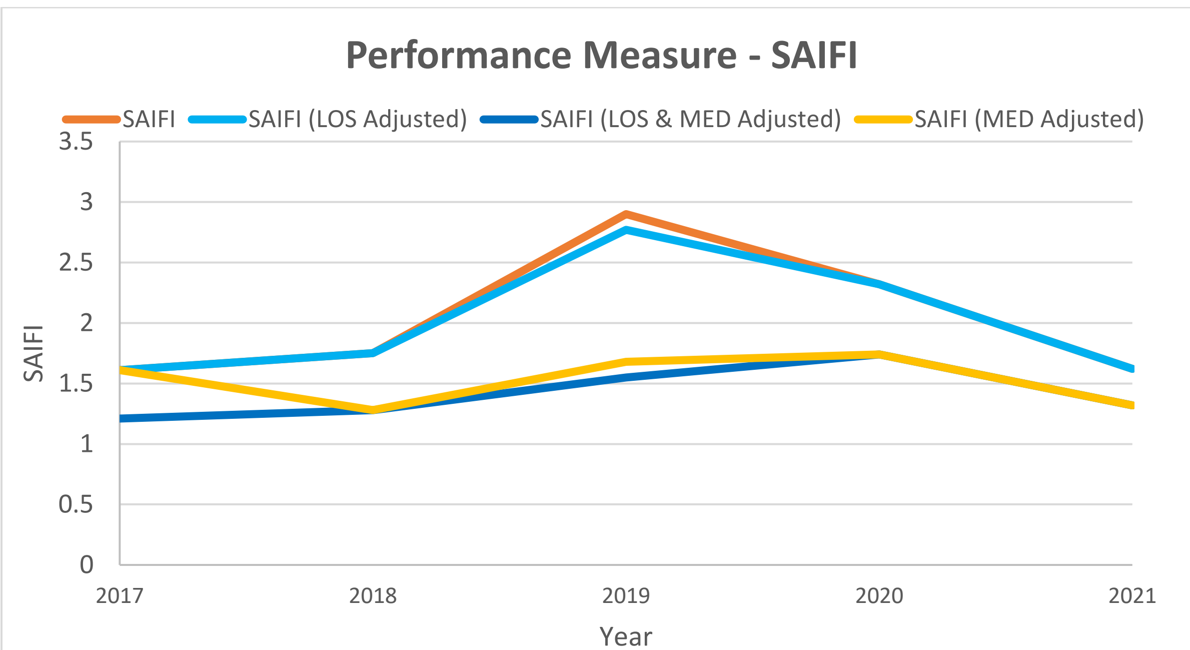


Figure 5.2-2: Performance Measure – SAIFI

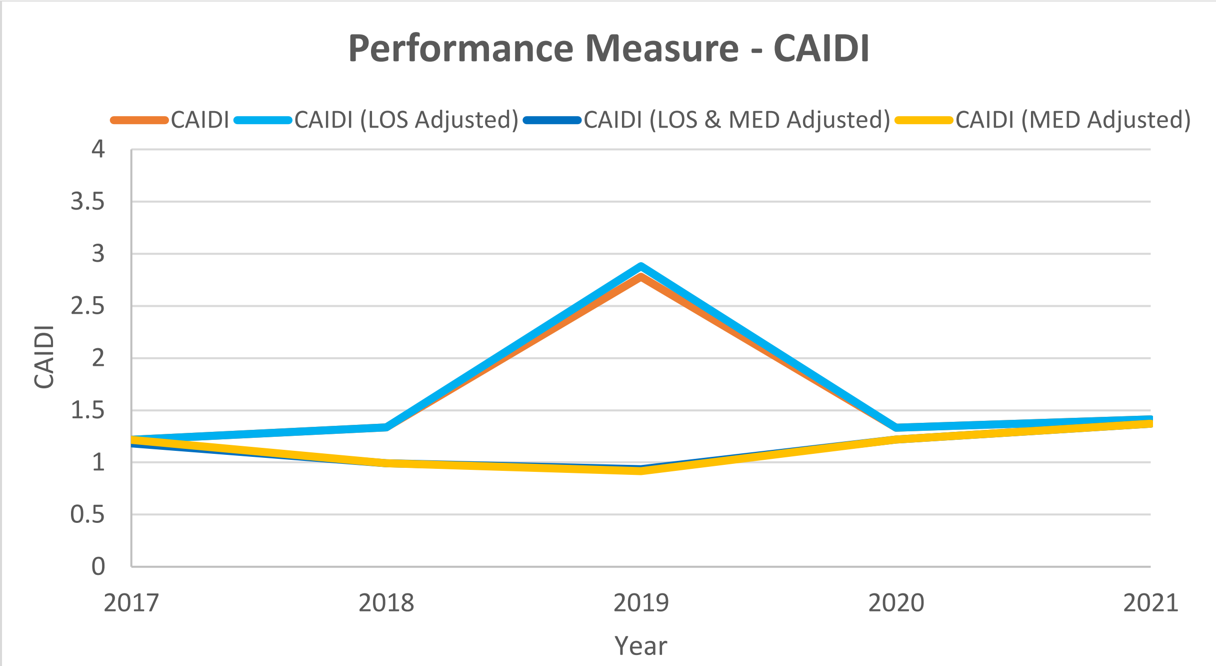


Figure 5. 2-3: Performance Measure – CAIDI

<u>Performance</u>

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

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

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

5.2.3.2.3 Outage Details for Years 2017-2021

<u>Major Events</u>

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

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

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

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

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

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

Outages Experienced by Cause Codes

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

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

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

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

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

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

Table 5.2-12 presents the count of outages broken down by cause code for the historical period, excluding MEDs. The number of outages is an indication of outage frequency and impacts customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer fewer outages with longer duration thereby reducing the overall impact on production and business disruption. PUC continues to assess and execute capital and O&M projects to manage the number of outages experienced.

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

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

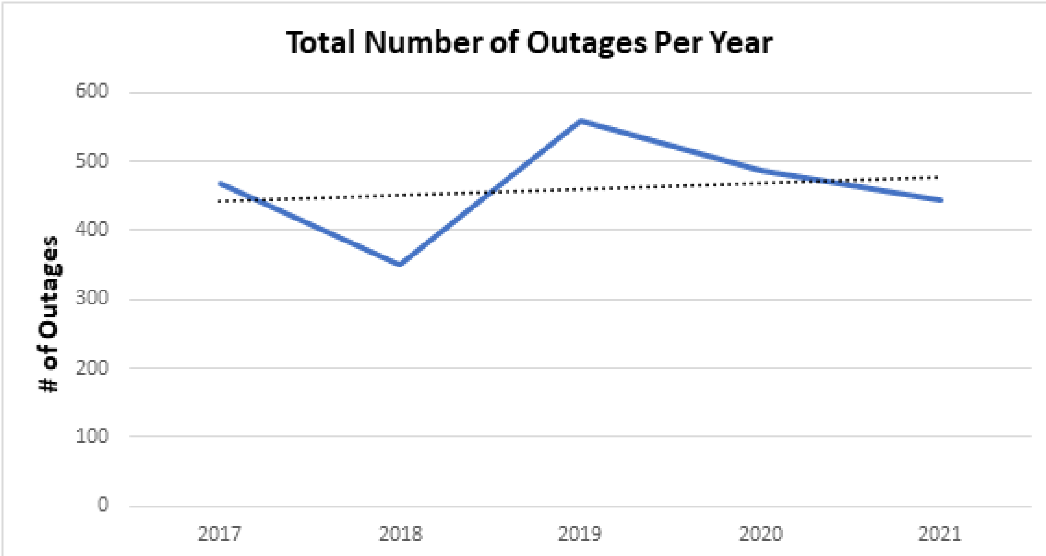


Figure 5.2-3: Total Number of Outages by Year

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

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

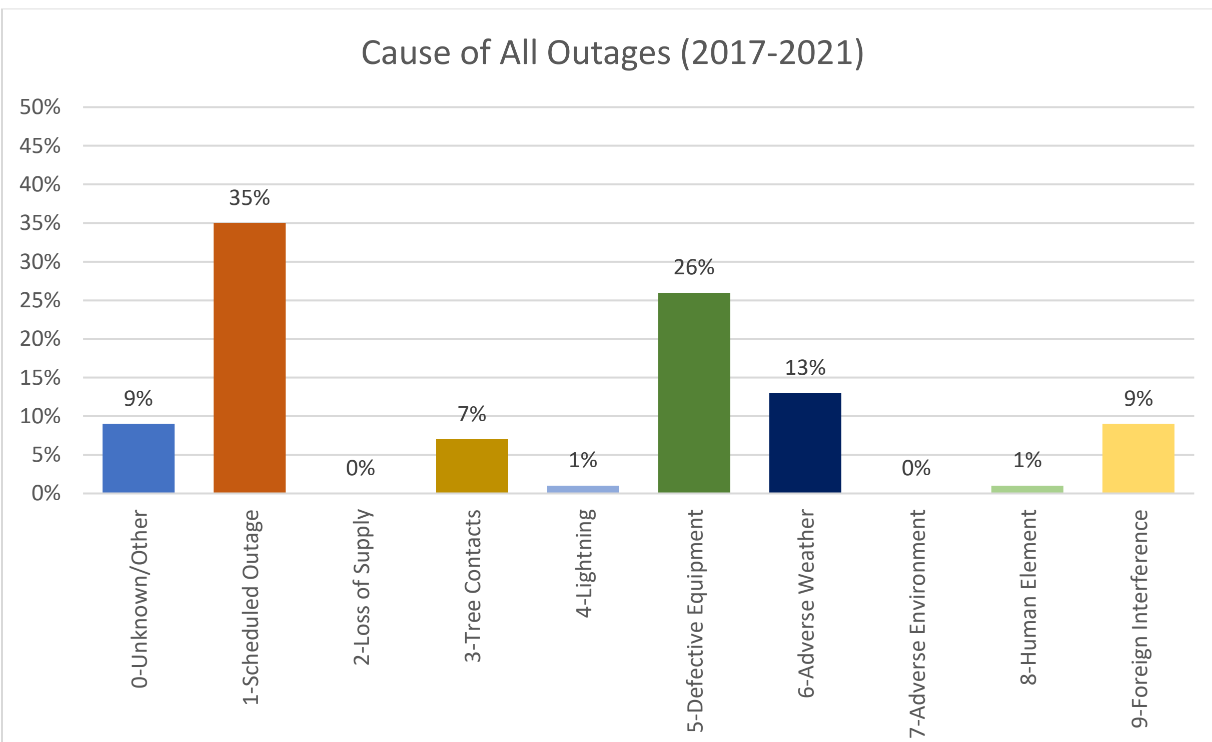


Figure 5.2-4: Percent of Outages by Cause Code

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

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

At 26%, Defective Equipment represents the next largest cause for outages on PUC's distribution system. Defective Equipment failures result from equipment failures due to condition deterioration, ageing effects or imminent failures detected from reoccurring maintenance programs. PUC has planned renewal investments to prioritize assets for replacement before experiencing a failure that may cause an outage. This includes replacing deteriorated poles, primary distribution cables, and underground infrastructure. PUC utilizes asset condition data from the recently completed ACA to assist in prioritizing investments in asset classes.

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

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

Customers Interrupted and Customers Hours Interrupted

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

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

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

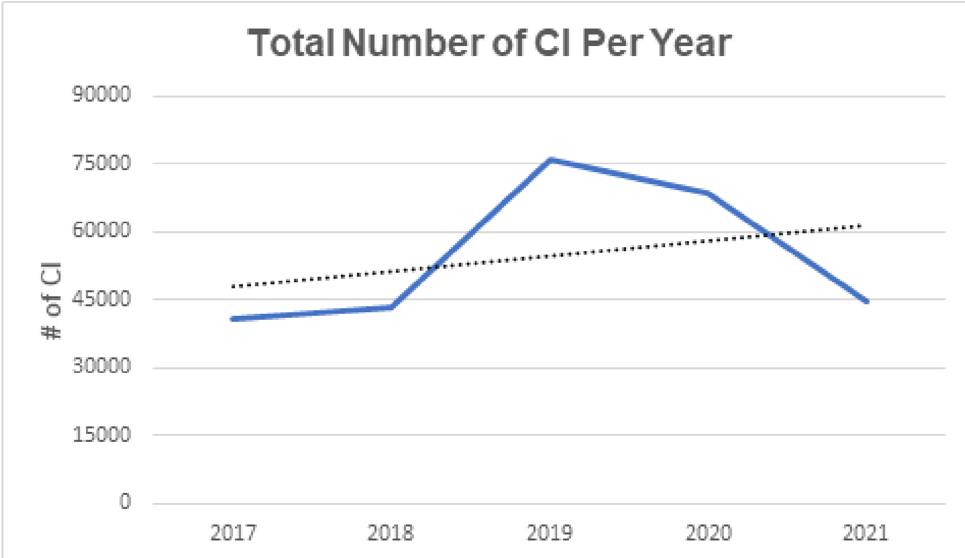


Figure 5.2-5: Total Number of Customers Interrupted by Year

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

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

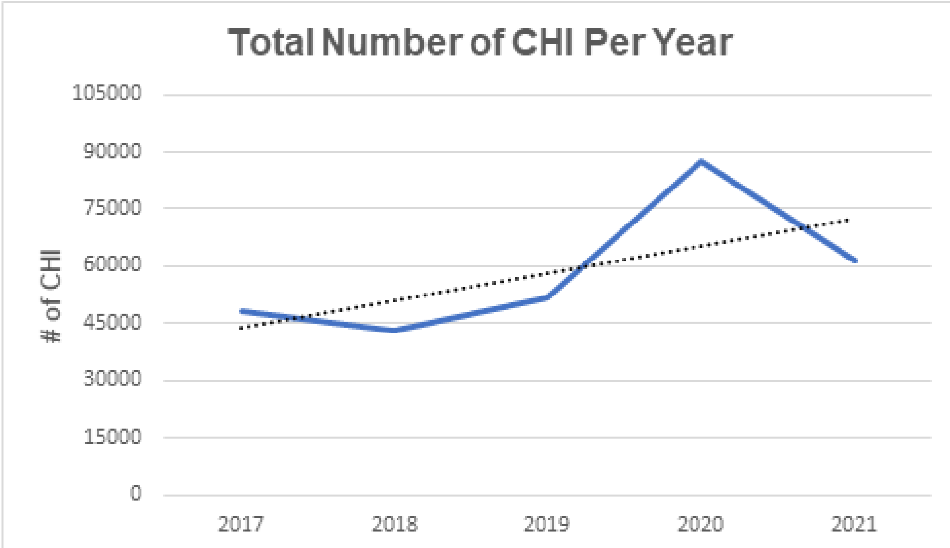


Figure 5.2-6: Total Number of Customers Hours Interrupted by Year

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

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

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

5.2.3.3 SSG Project Benefits on Service Quality and Reliability Performance

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

<u>Customer Focus</u>

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

<u>Operational Effectiveness</u>

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

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

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

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

Table 5.2-15: Cost Control Performance

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

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

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

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

Public Policy Responsiveness

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

Financial Performance

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

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

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

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

5.2.3.4 Distributor Specific Reliability Targets

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

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

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

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

5.3 Asset Management Process

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

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

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

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

5.3.1 Planning Process

5.3.1.1 Overview

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

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

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

PUC's AM Objectives form the high-level philosophy framework for its capital program. These objectives help to define the content of the programs and the major projects in the capital expenditure plan to be able to sustain PUC's electrical distribution system. The objectives guide PUC to make effective capital investment decisions, which inherently make the best use of, and maximize the value of the assets to the company. The objectives identify an initial starting point and continue to be developed, enhanced, or adjusted as necessary to be aligned with the business environment that the company operates in and help to encourage the process of continuous improvement. The AM Objectives have been qualitatively integrated into PUC's capital investment process to prioritize investments for several years including the bridge and Test Year.

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

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

Decisions involving investment into fixed assets play a major role in determining the optimal performance of distribution system fixed assets. Investments that are either oversized or made too far in advance of the actual system need may result in non-optimal operation. On the other hand, investments not made on time when warranted by system needs raise the risk of performance targets not being achieved and contribute to sub-optimal operation. Optimal operation of the distribution system is achieved when "right sized" investments into renewal and replacement (capital investments) and into asset repair, rehabilitation and preventative maintenance are planned and implemented based on a "just-in-time" approach. In summary, the overarching objective of the AM strategy is to find the right balance between capital investments in new infrastructure and operating and maintenance costs so that the combined total cost over the life of the asset is minimized.

5.3.1.2 Important Changes to Asset Management Process since last DSP Filing

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

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

5.3.1.3 Process

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

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

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

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

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

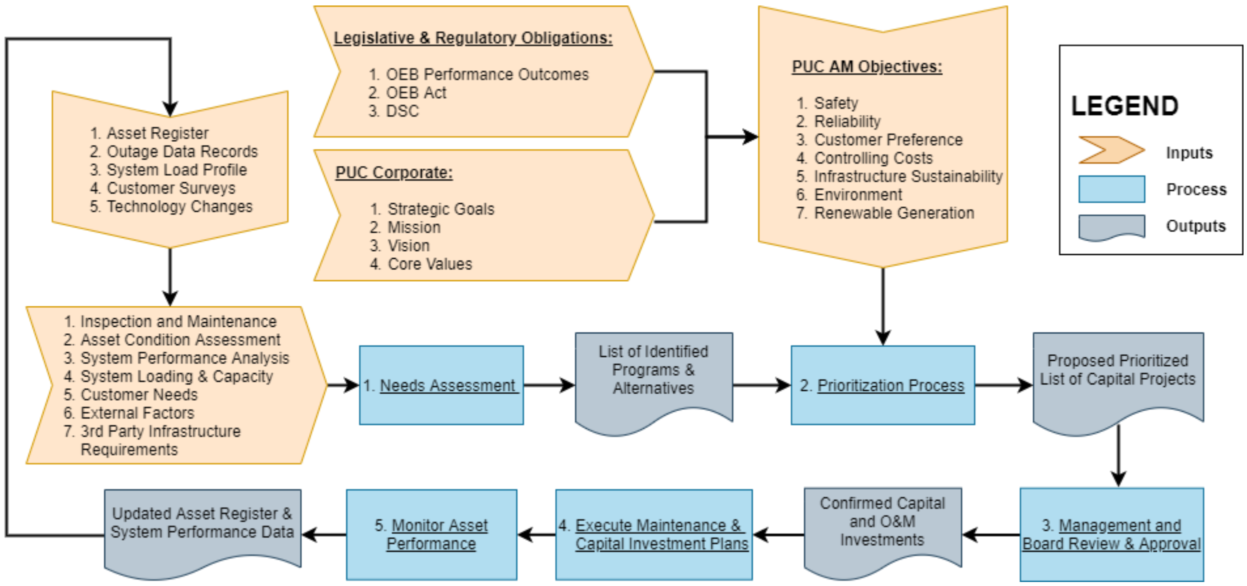


Figure 5.3-1: PUC's AM Process

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

Step 1 - Needs Assessment

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

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

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

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

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

Step 2 – Prioritization Process

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

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

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

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

Table 5.3-2: Prioritization Criteria & Weights

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

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

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

Step 3 – Management and Board Review & Approval

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

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

Step 4 – Execute Maintenance & Capital Investment Plans

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

Step 5 – Monitor Asset Performance

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

5.3.1.4 Data

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

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

Asset Register

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

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

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

Customer Survey Results & Needs

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

Technology Changes

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

Inspection & Maintenance

PUC maintains a full schedule of distribution asset inspection and maintenance programs operating on a three-year rotation as required by the OEB's DSC. Inspection, maintenance, and operational data are collected and stored which is used to support PUC's operating and capital expenditure plans.

Completion of the inspection and maintenance programs is not only a matter of compliance but the results from the inspection and maintenance programs allow a continual update of the asset database. The programs allow for assets to be inspected and assessed for any necessary actions that need to be taken promptly in a proactive approach. PUC's inspection and maintenance programs are audited every year as required by Ontario Regulation 22/04. Further information on PUC's maintenance and inspection practices can be found in Section 5.3.3.

Asset Condition Assessment

An ACA was undertaken in 2021 to assess the condition of the system and to have empirical data on which to base the revised project prioritization. The ACA involves the interpretation of condition and performance data of key assets to assess the overall condition of the asset. Essentially, the ACA is a key supporting tool for developing an optimized lifecycle plan for asset sustainability. The results of the ACA were incorporated into a formalized capital plan and have resulted in the revision of project prioritization within the service area for the forecast period. Further information on the ACA results can be found in Section 5.3.2.2.2, and the full ACA Report is included in Appendix H.

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

Outage Data Records & System Performance Analysis

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

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

System Loading & Capacity

Load forecasting and capital growth planning continue to be the underlying basis for the near and longer-term capital requirements for new or enhanced capacity. The loading and capacity information help to identify system needs and constraints. The information is collected on system peak loading at many points in the system, and the data is analyzed to measure the risk of system overloading and to mitigate any concerns. Further information can be found in Section 5.3.2.2.1.

External Drivers

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

- Political – governments have their directions and strategies that PUC needs to be mindful of and to be in alignment with their plans.
- Economic – economic growth and decline within PUC's service area as well as the shift of business operations within residential units.
- Social – changes in the environment that illustrate customer needs and wants.
- Technological – innovation and development within the electrical/utility sector which includes automation, technology awareness, electric vehicle penetration, battery storage and new services.
- Environmental – ecological and environmental aspects that can affect PUC's operations or demand which includes renewable resources, weather or climate changes, and utility responsibility initiatives.
- Regulatory/Legal – legal allowances and/or changing requirements from the OEB as well as additional legal operations such as health and safety requirements, labour laws, and consumer protection laws.

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

Third Party Infrastructure Requirements

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

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

Legislative & Regulatory Obligations

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

<u>Corporate objectives</u>

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

<u>AM Objectives</u>

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

5.3.2 Overview of Assets Managed

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

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

5.3.2.1 Description of Service Area

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

5.3.2.1.1 Overview of Service Area

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

5.3.2.1.2 Customers Served

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

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

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

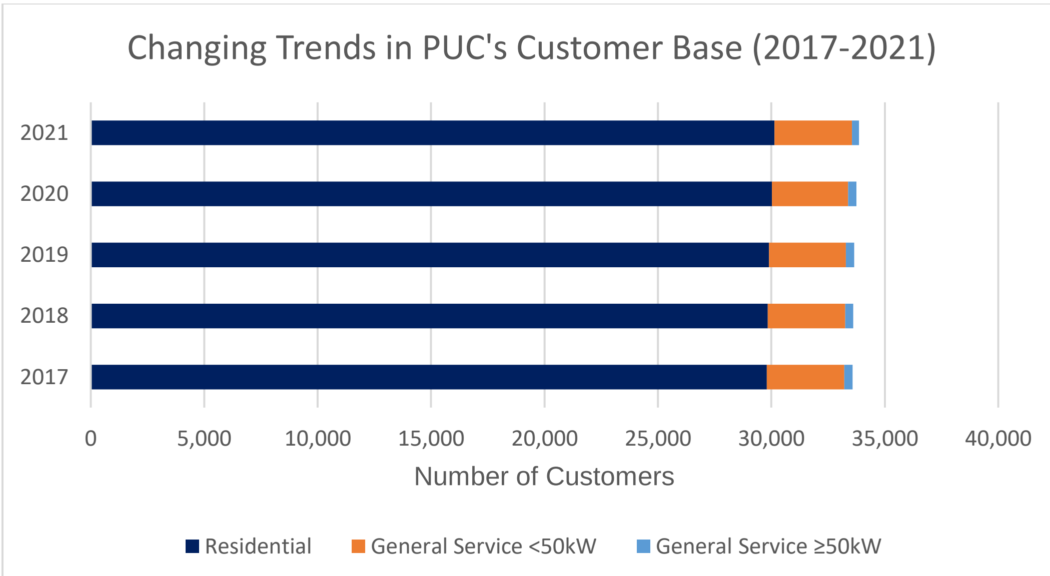


Figure 5.3-2: Change in Customer Base by Category over Historical Period

5.3.2.1.3 System Demand & Efficiency

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

Table 5.3-5: Peak System Demand Statistics

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

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

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

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

Table 5.3-6: Efficiency of kWh Purchased by PUC

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

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

5.3.2.1.4 Summary of System Configuration

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

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

Figure 5.3-3: Distribution Station Locations

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

Table 5.3-7: 115/34.5 kV Substation Ratings

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

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

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

Table 5.3-8: 12 kV Distribution Station Ratings

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

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

Table 5.3-9: 4.2 kV Station Ratings

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

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

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

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

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

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

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

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

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

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

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

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

5.3.2.1.5 Climate

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

5.3.2.1.6 Economic Growth

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

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

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

5.3.2.2 Asset Information

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

5.3.2.2.1 Asset Capacity & Utilization

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

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

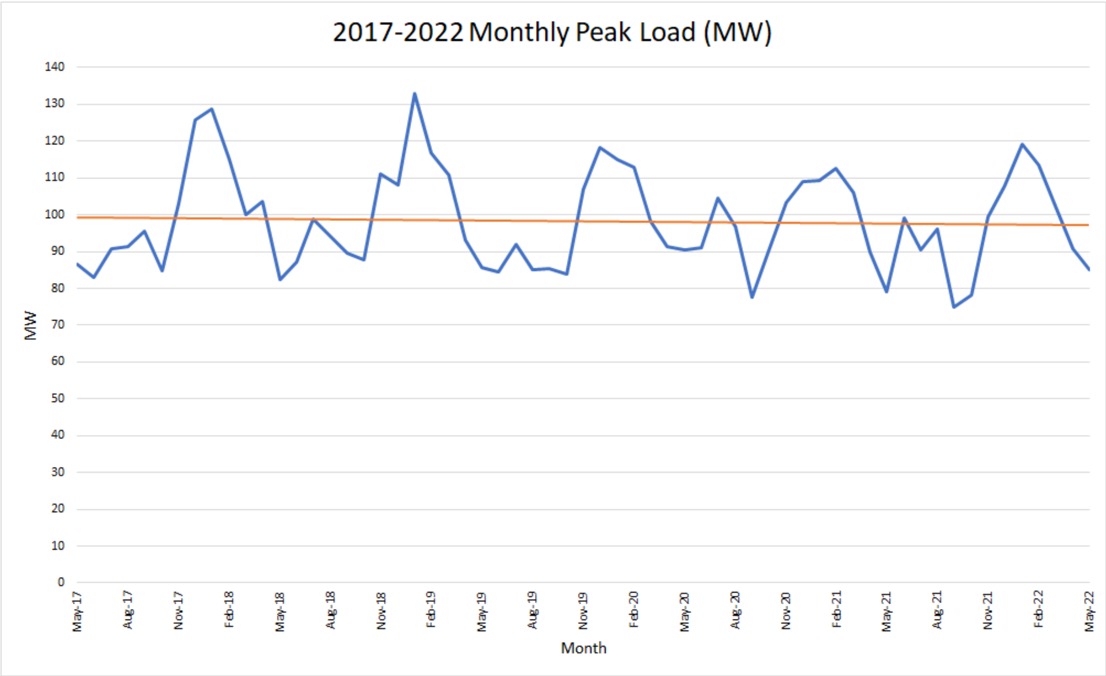


Figure 5.3-4: PUC Service Territory – Past Eleven Year System Loading

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

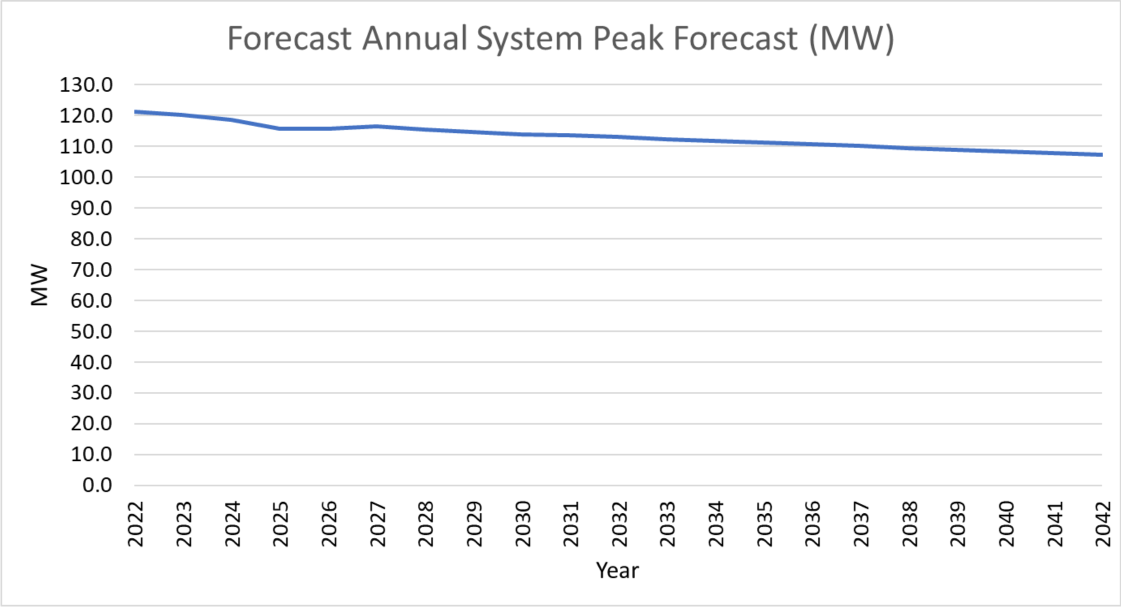


Figure 5.3-5: PUC Service Territory – Peak Demand Forecast

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

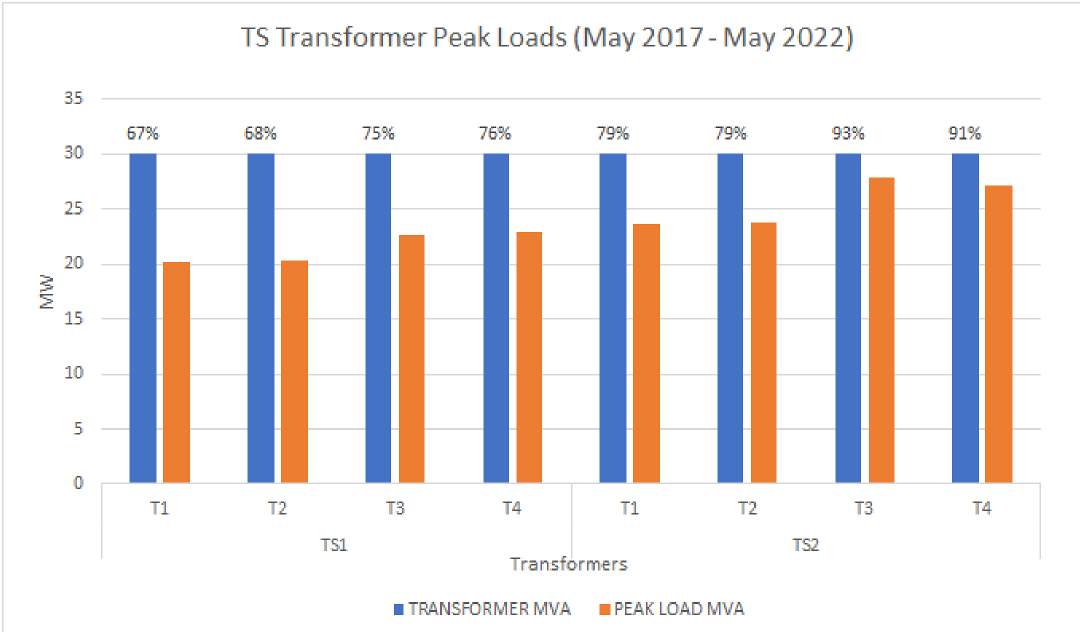


Figure 5.3-6: 34.5kV Substation Ratings and Loading Level

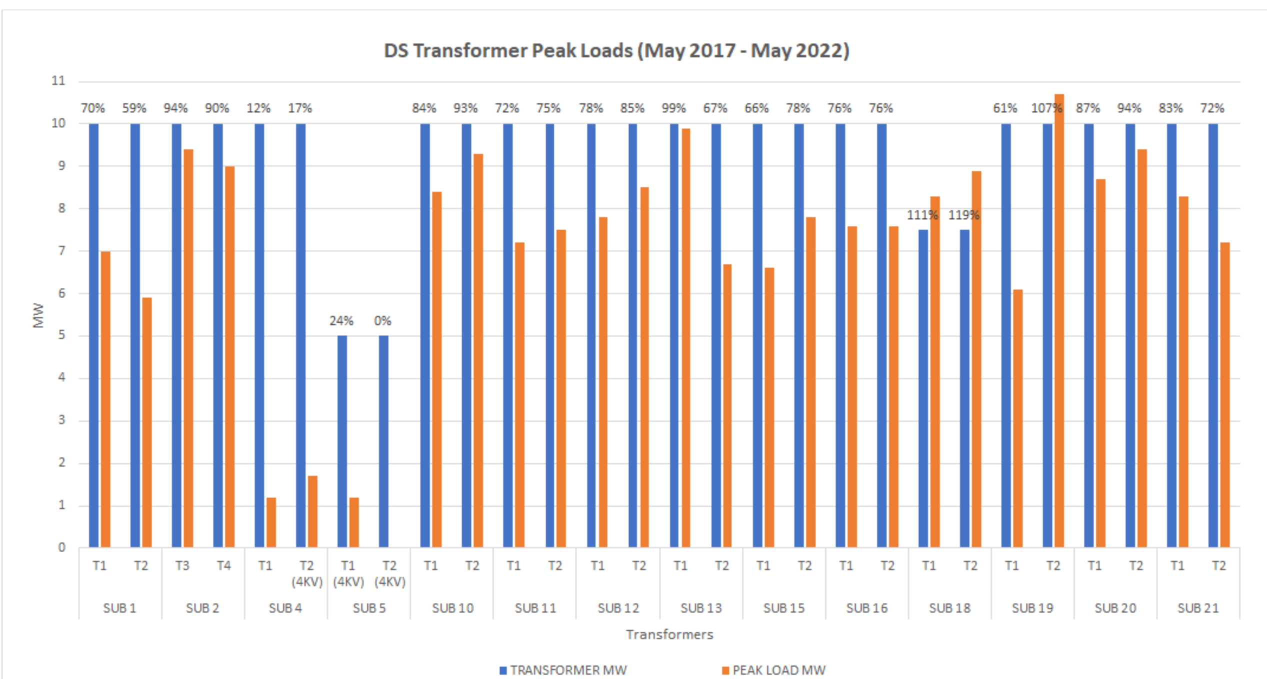


Figure 5.3-7: 12.5kV Substation Ratings and Loading Level

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

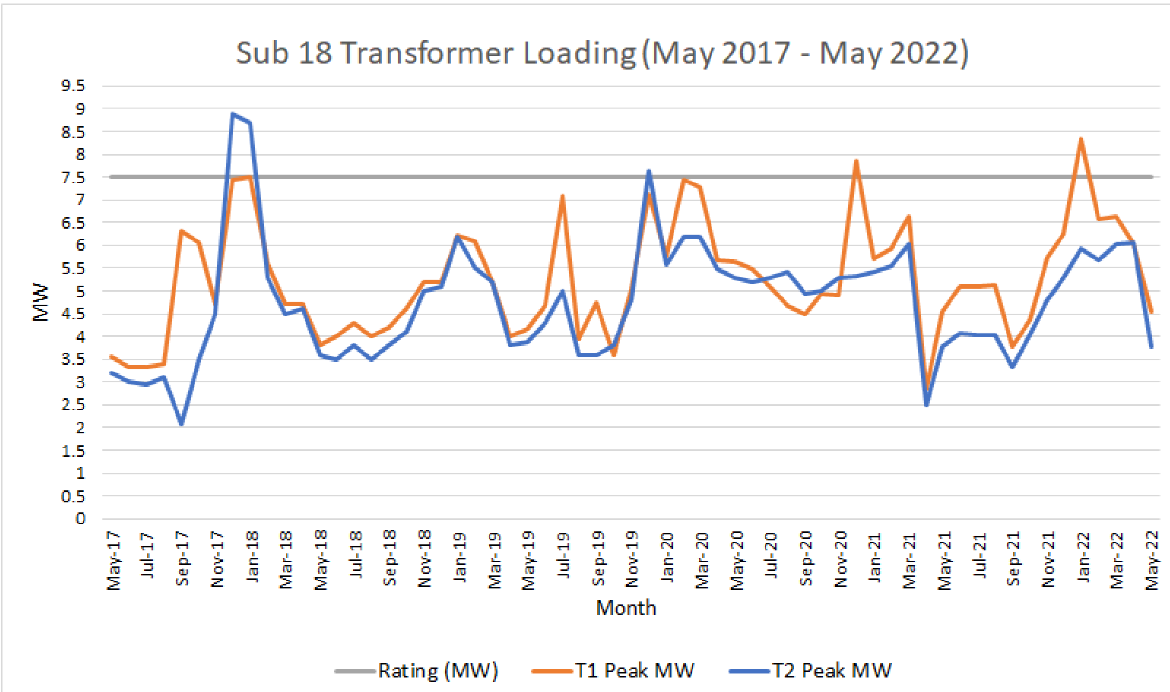


Figure 5.3-8: Five Year Sub 18 Transformer Peak Monthly Loads

5.3.2.2.2 Asset Condition & Demographics

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

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

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

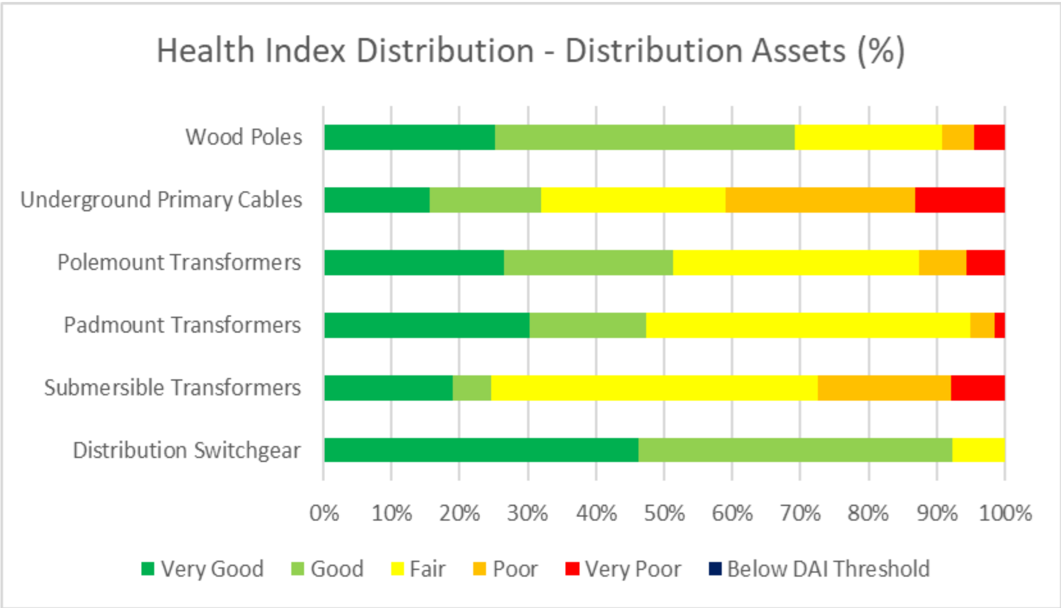


Figure 5.3-9: Distribution Assets Health Index Results

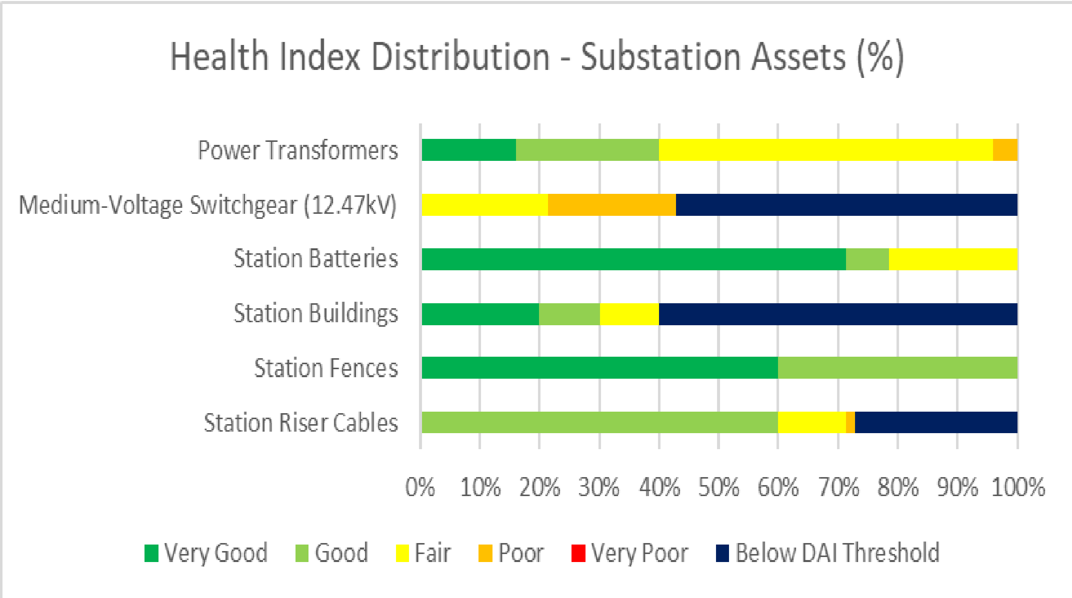


Figure 5.3-10: Substation Assets Health Index Results

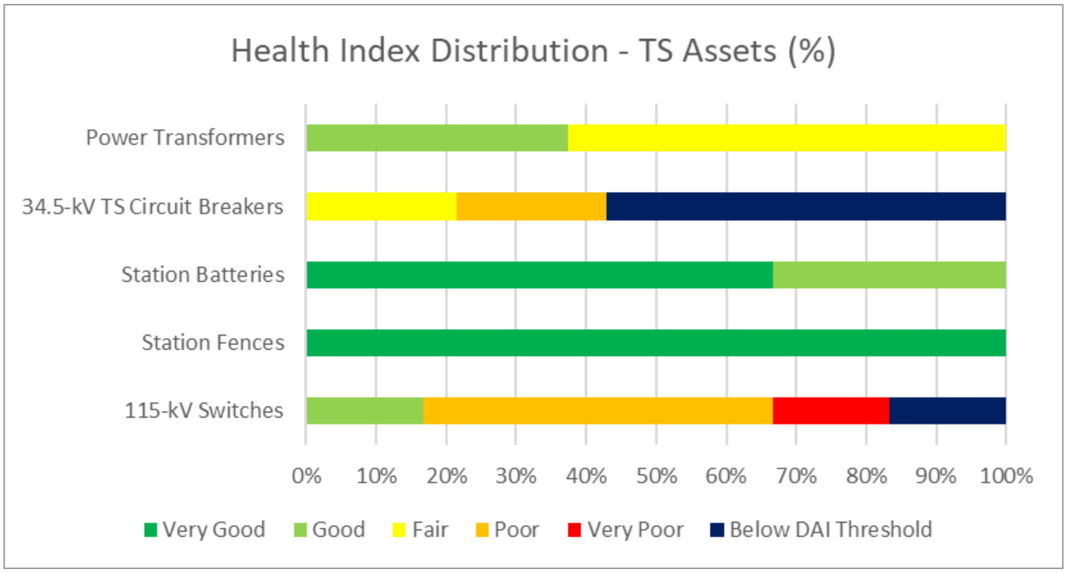


Figure 5.3-11: TS Station Assets Health Index Results

5.3.2.2.2.1 Condition of Distribution Assets

Wood Poles

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

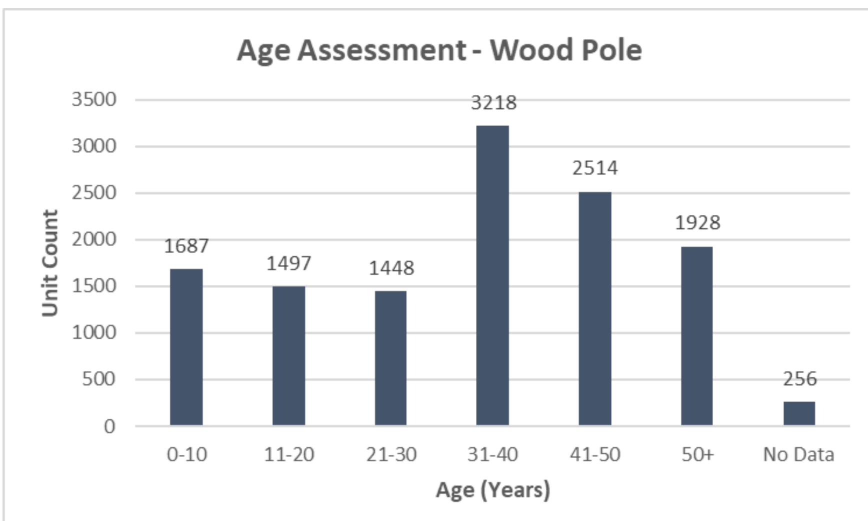


Figure 5.3-12: Wood Poles Age Demographics

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

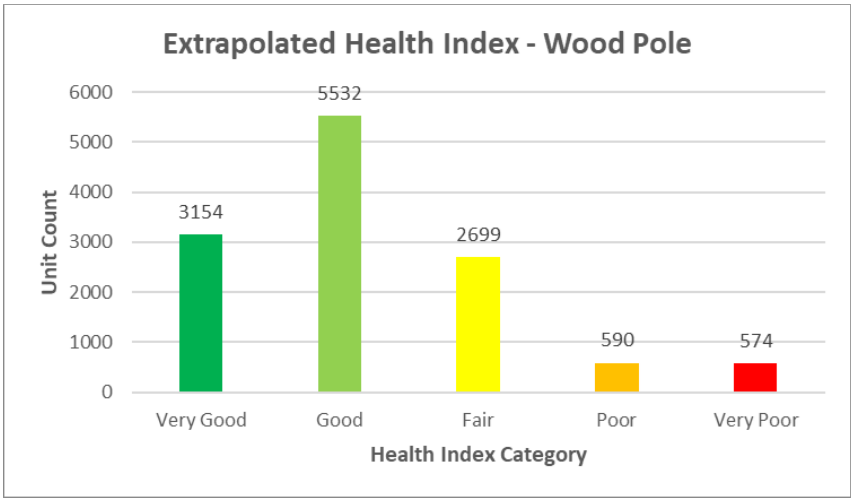


Figure 5.3-13: HI Results- Extrapolated Wood Pole

<u>Overhead Primary Conductors</u>

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

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

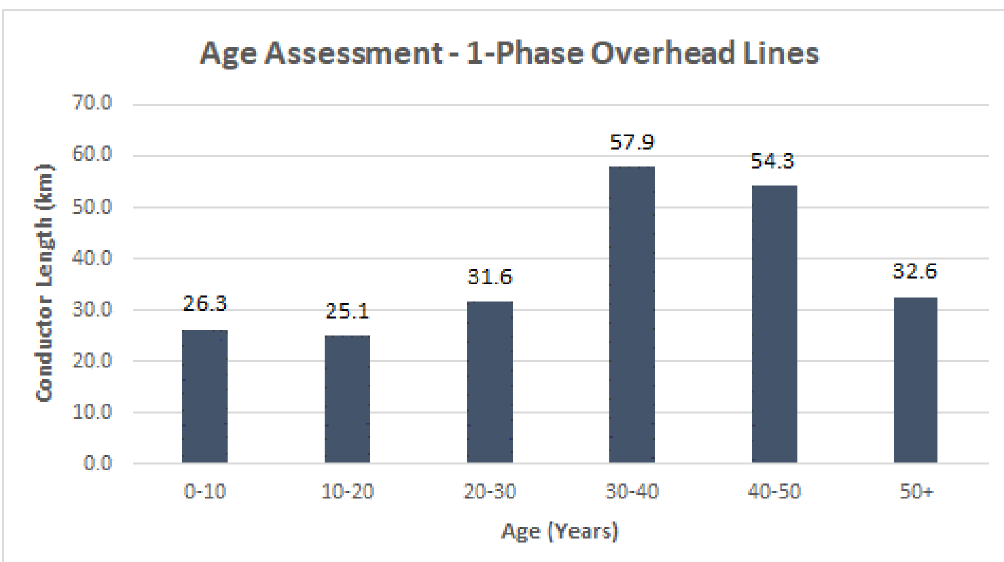


Figure 5.3-14: 1-Phase Overhead Line Age Demographics

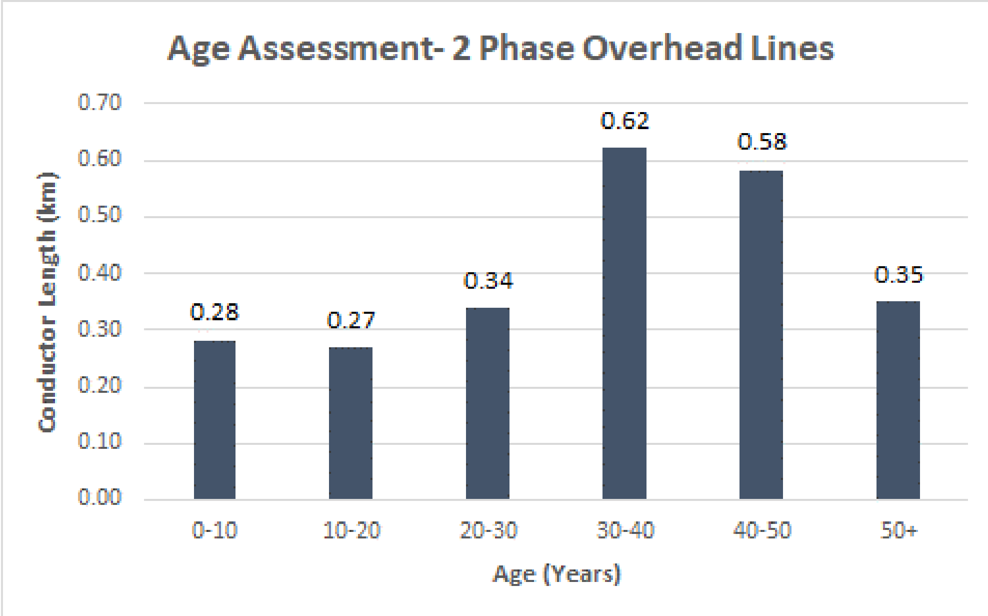


Figure 5.3-15: 2-Phase Overhead Lines Age Demographics

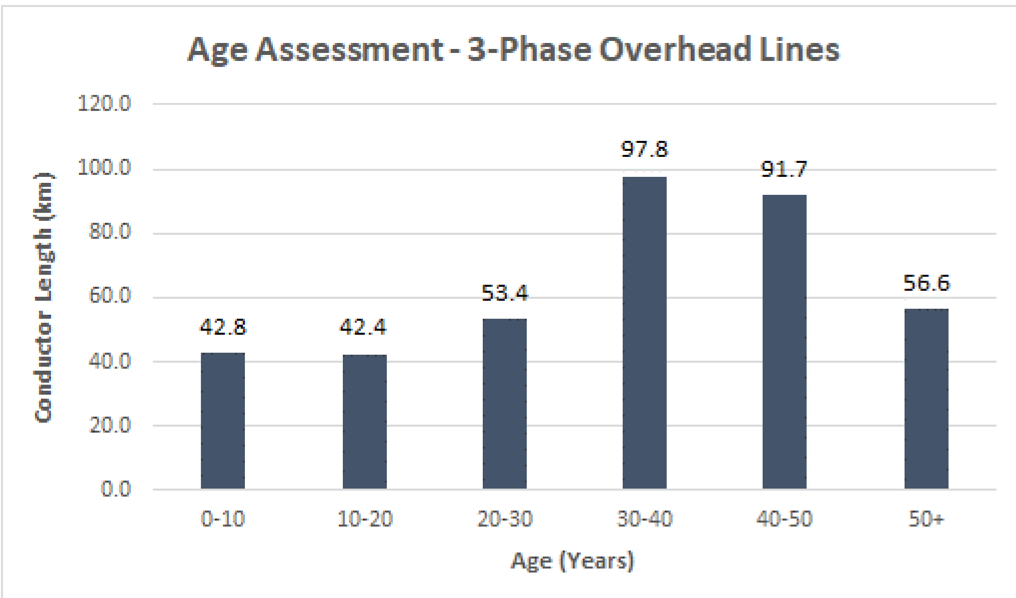


Figure 5.3-16: 3-Phase Overhead Line Age Demographics

<u>Underground Primary Cable</u>

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

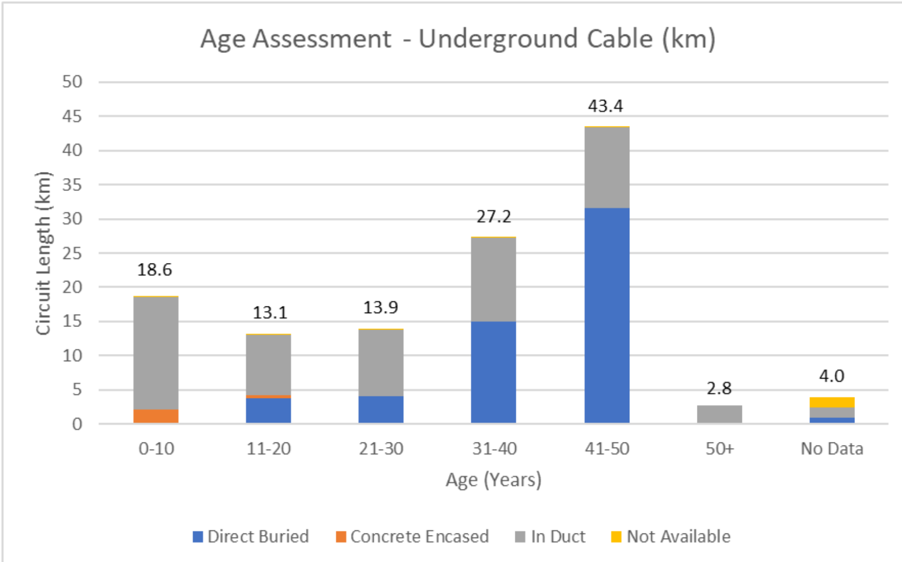


Figure 5.3-17: Overall Underground Primary Cable Age Demographics

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

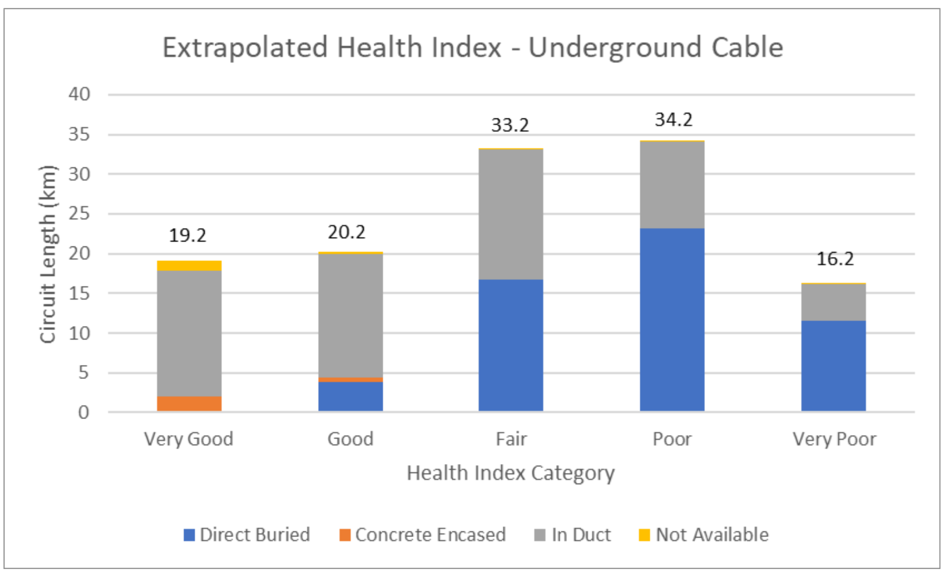


Figure 5.3-18: HI Results- Extrapolated Underground Cable

<u>Polemount Transformers</u>

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

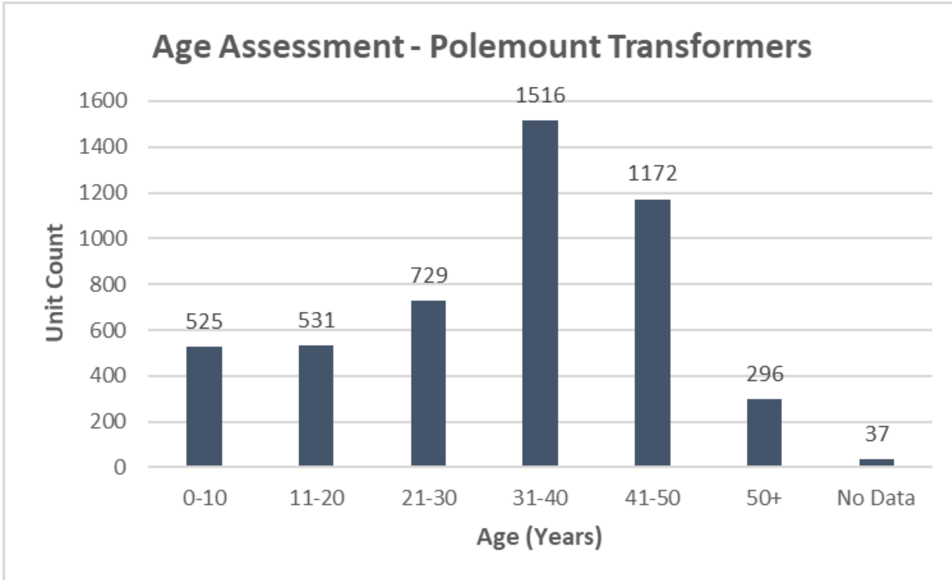


Figure 5.3-19: Pole-Mount Transformer Age Demographics

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

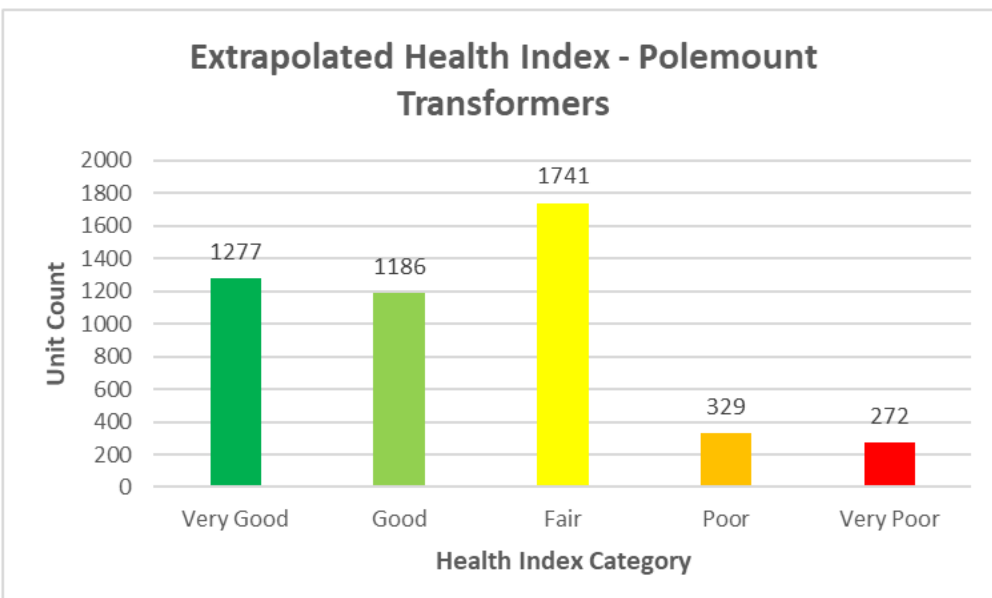


Figure 5.3-20: HI Results – Extrapolated Polemount Transformer

<u>Padmounted Distribution Transformers</u>

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

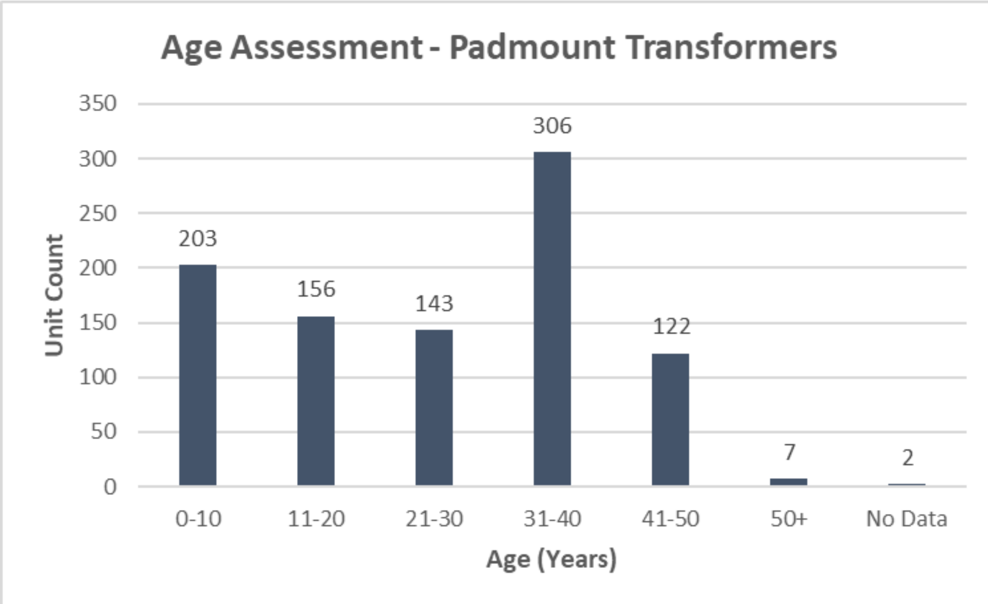


Figure 5.3-21: Pad-mount Transformer Age Demographics

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

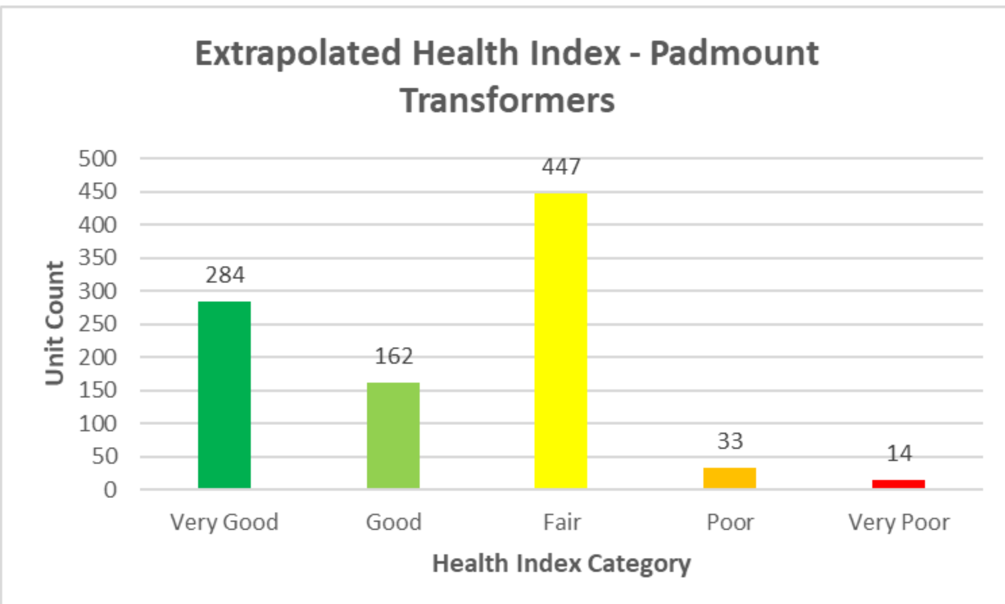


Figure 5.3-22: HI Results- Extrapolated Padmount Transformer

<u>Submersible Transformers</u>

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

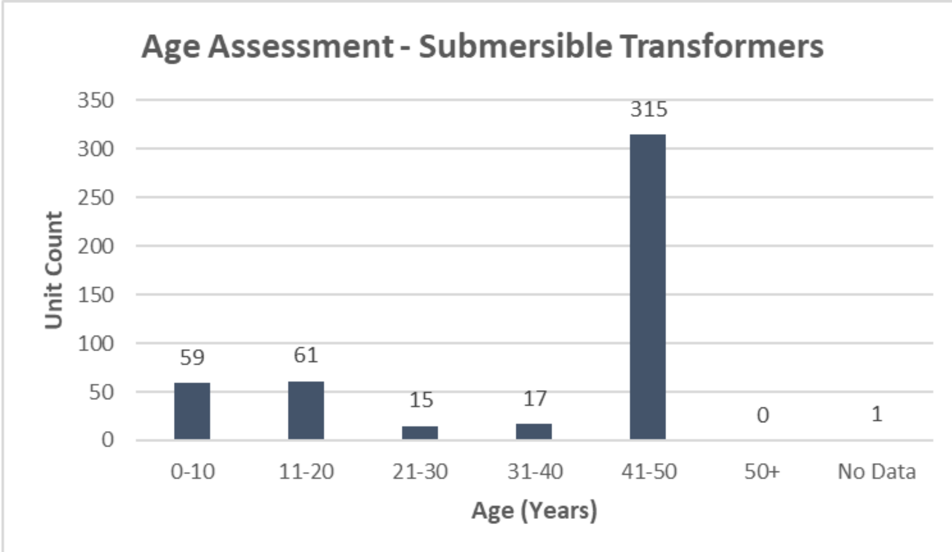


Figure 5.3-23: Submersible Transformers Age Demographics

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

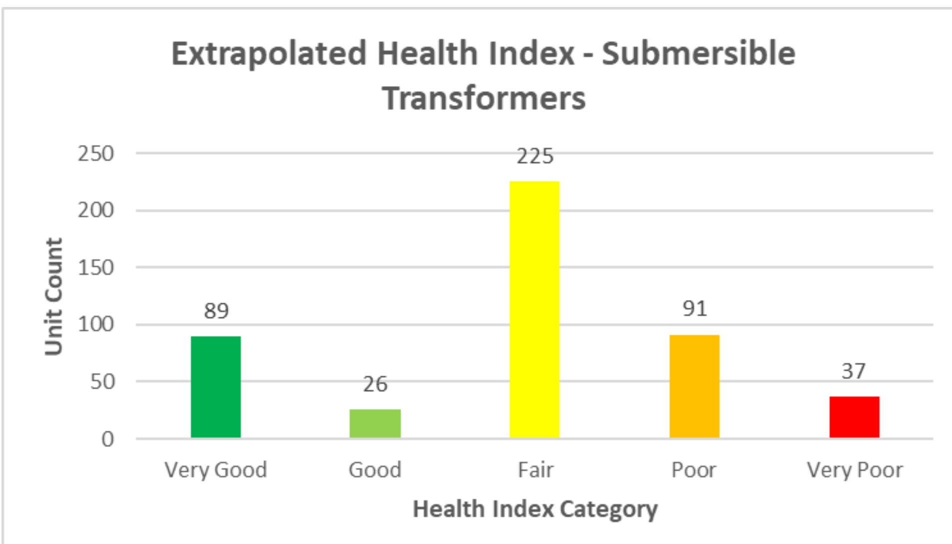


Figure 5.3-24: HI Results- Extrapolated Submersible Transformer

Underground Switches

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

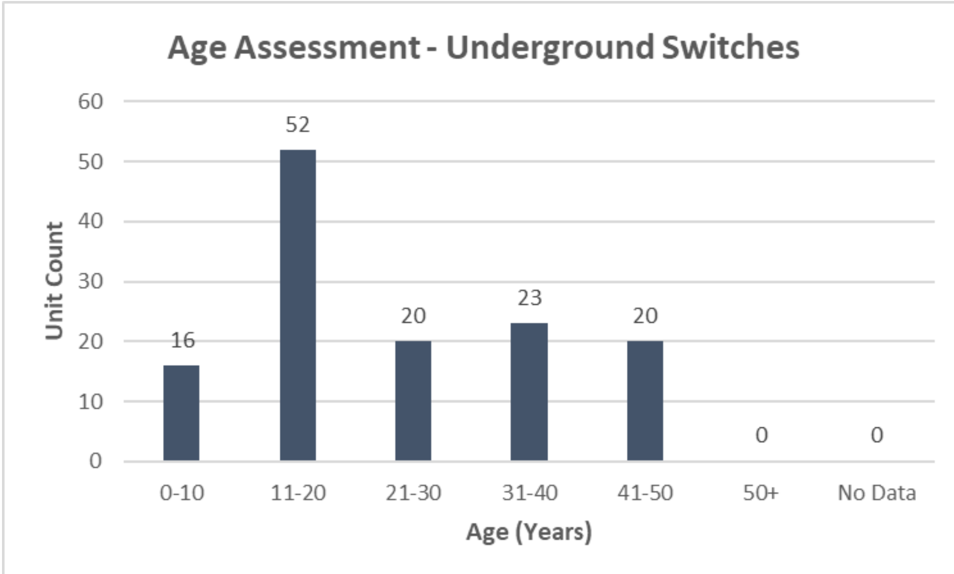


Figure 5.3-25: Underground Switch Age Demographics

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

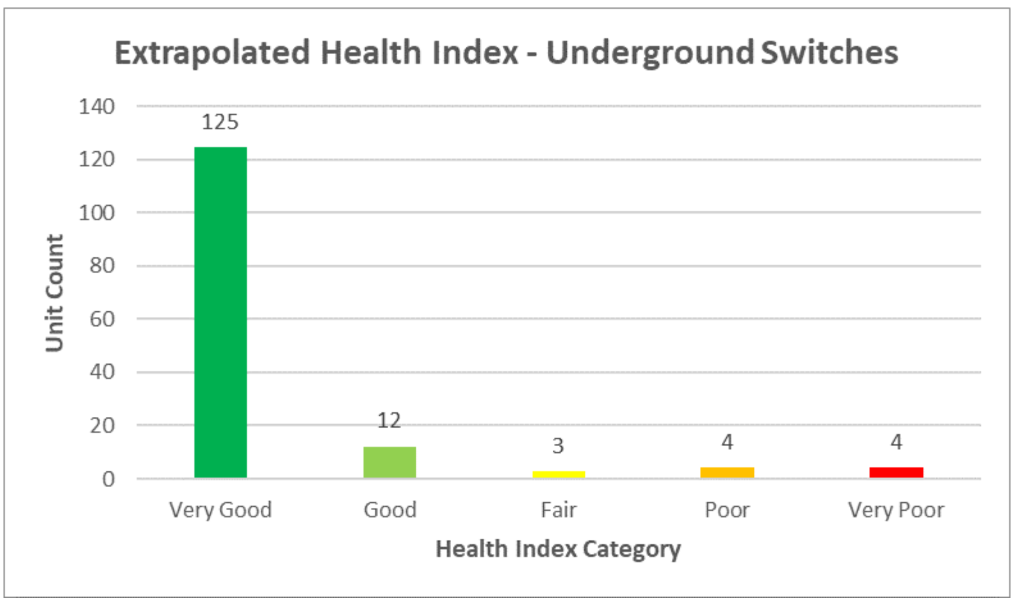


Figure 5.3-26: HI Results - Extrapolated Underground Switch

<u>Distribution Switchgear</u>

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

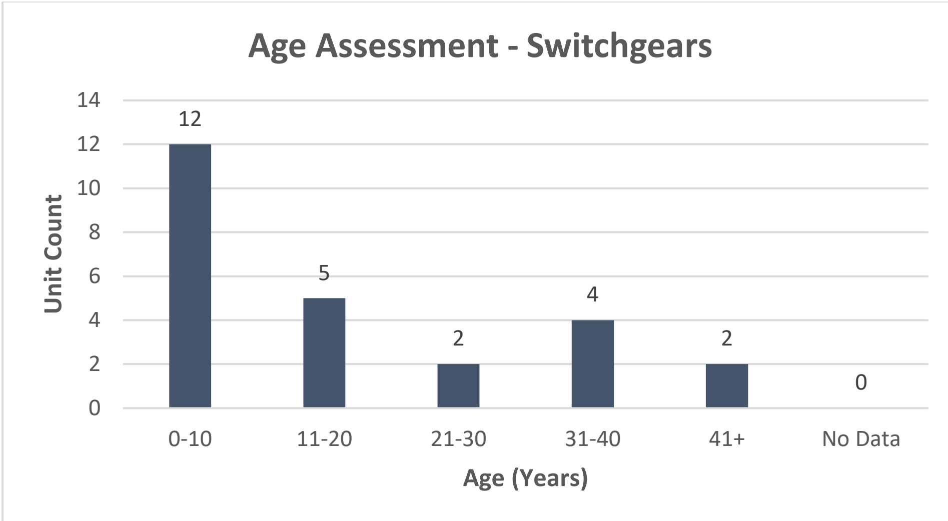


Figure 5.3-27: Switchgear Age Demographics

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

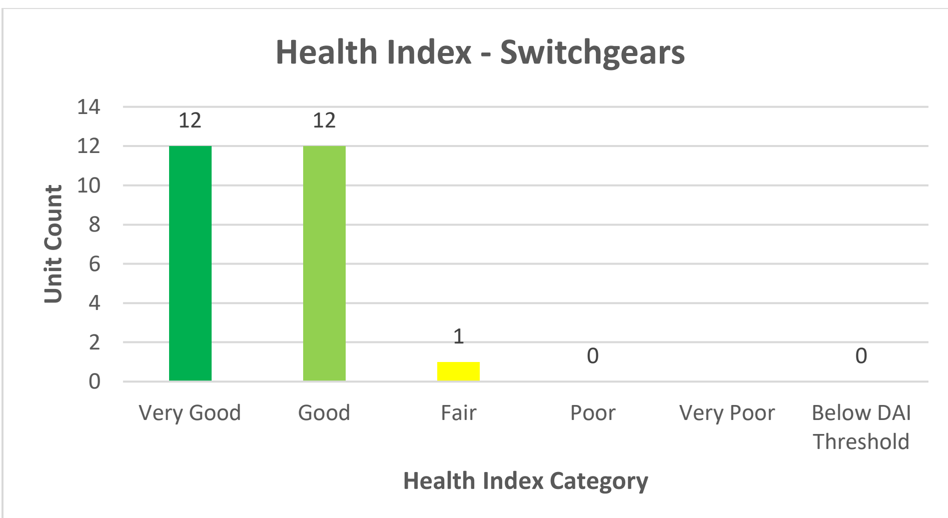


Figure 5.3-28: HI Results – Distribution Switchgear

5.3.2.2.2.2 Condition of Station Assets

Power Transformers

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

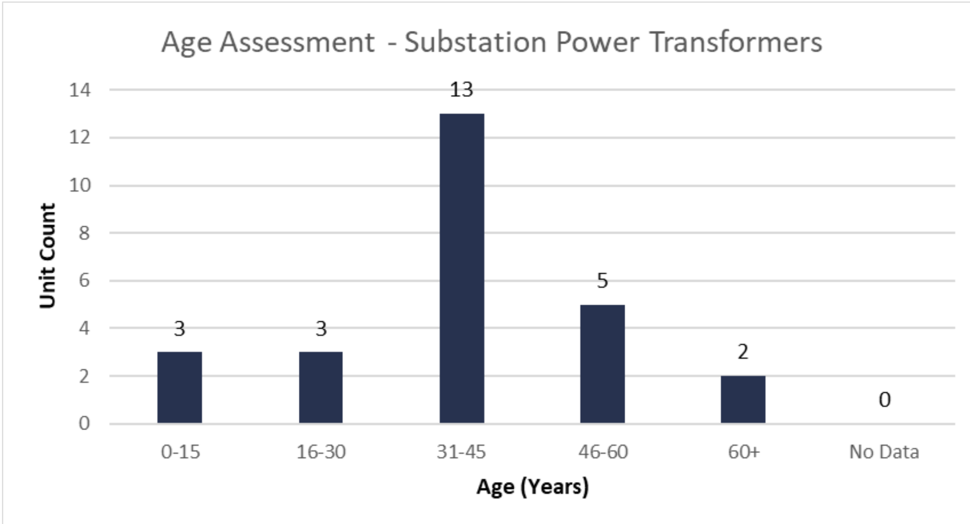


Figure 5.3-29: Substation Power Transformer Age Demographics

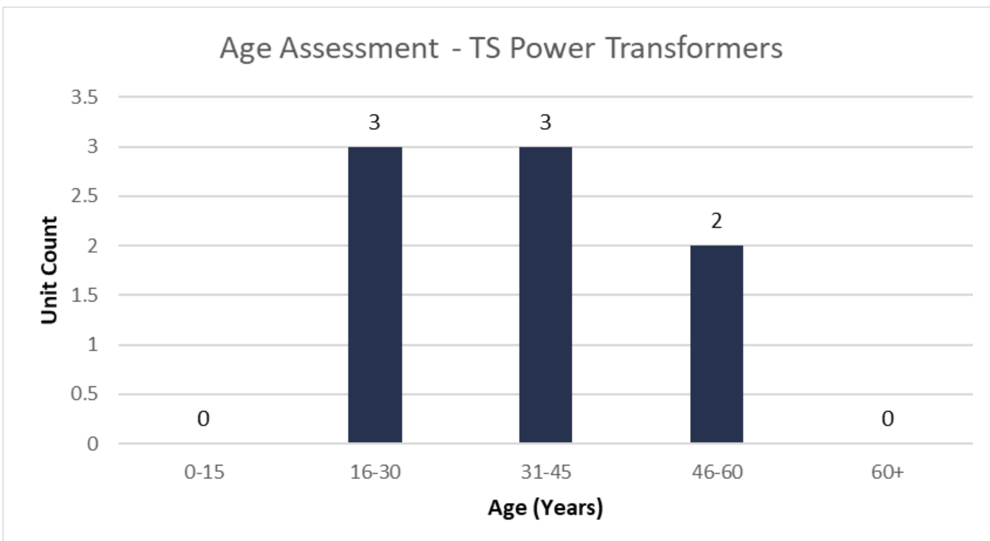


Figure 5.3-30: TS Power Transformer Age Demographics

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

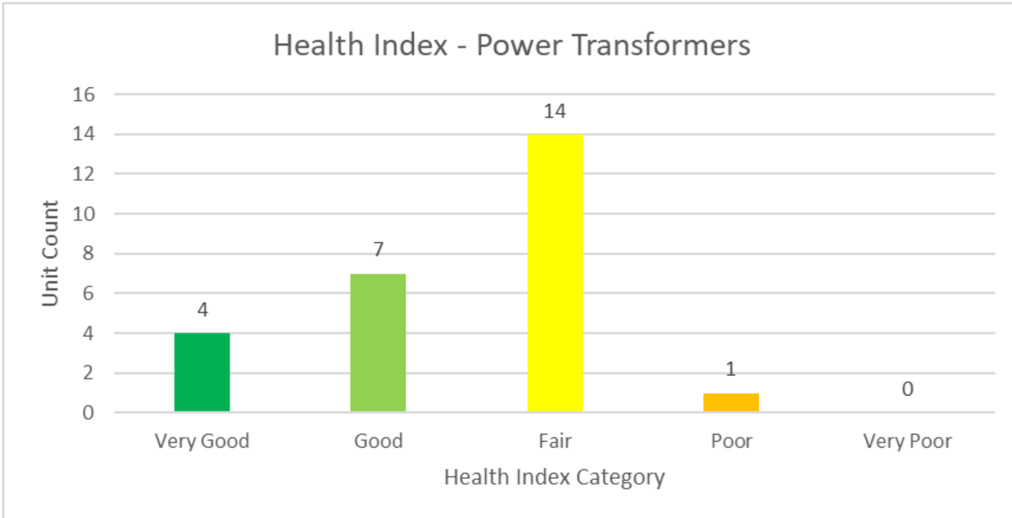


Figure 5.3-31: HI Results - Substation Power Transformer

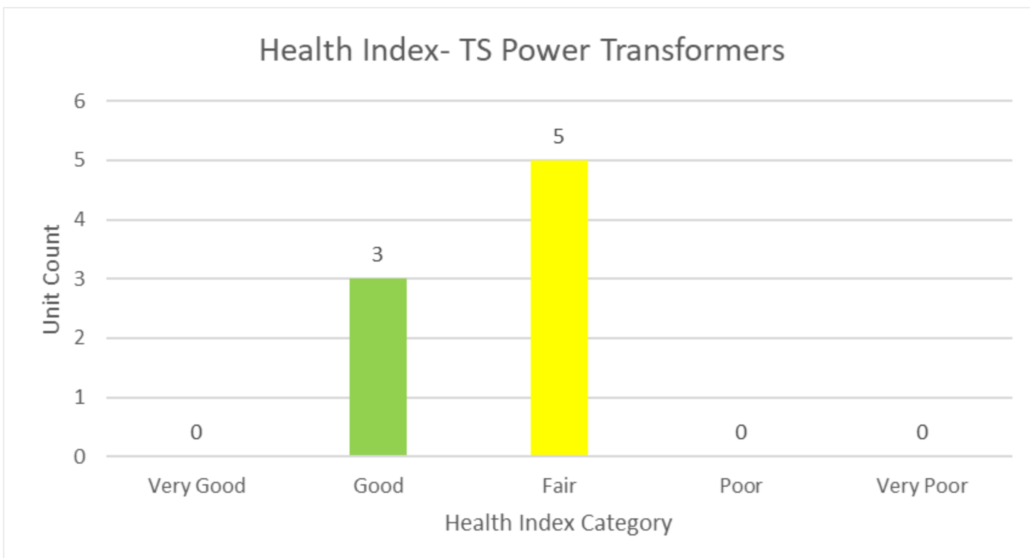


Figure 5.3-32: HI Results - TS Power Transformer

<u>Medium Voltage Station Switchgear</u>

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

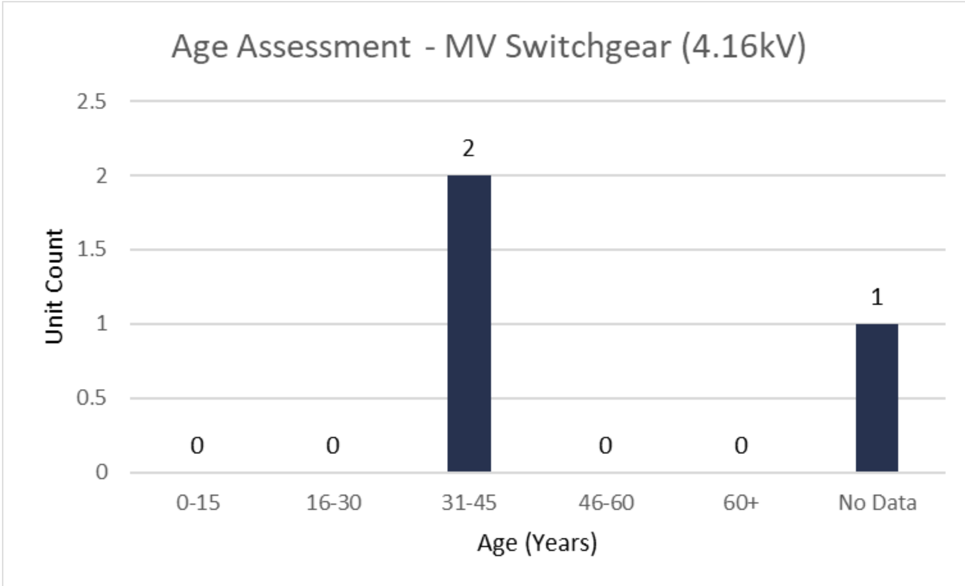


Figure 5.3-33: 4.16kV Substation Switchgear Age Demographics

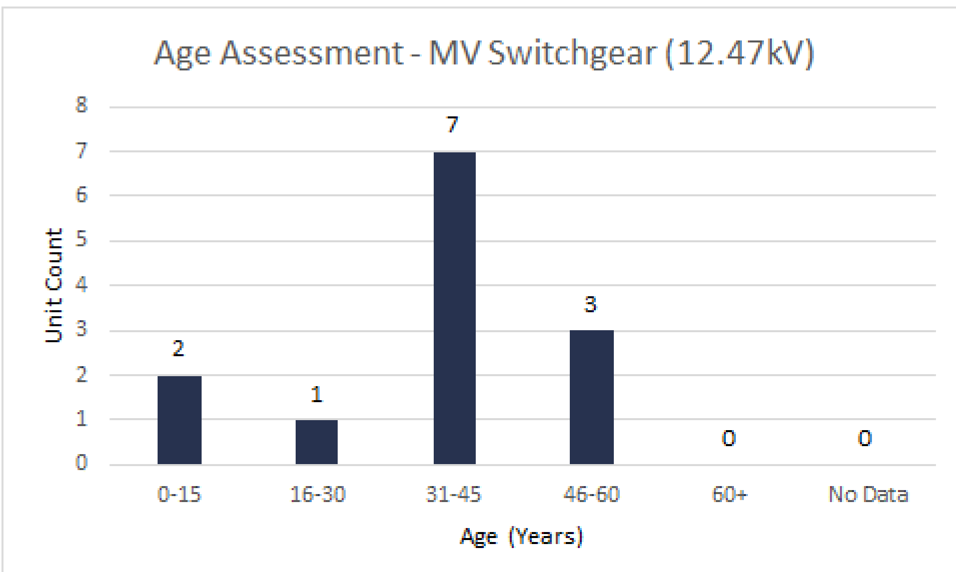


Figure 5.3-34: 12.47kV Substation Switchgear Age Demographics

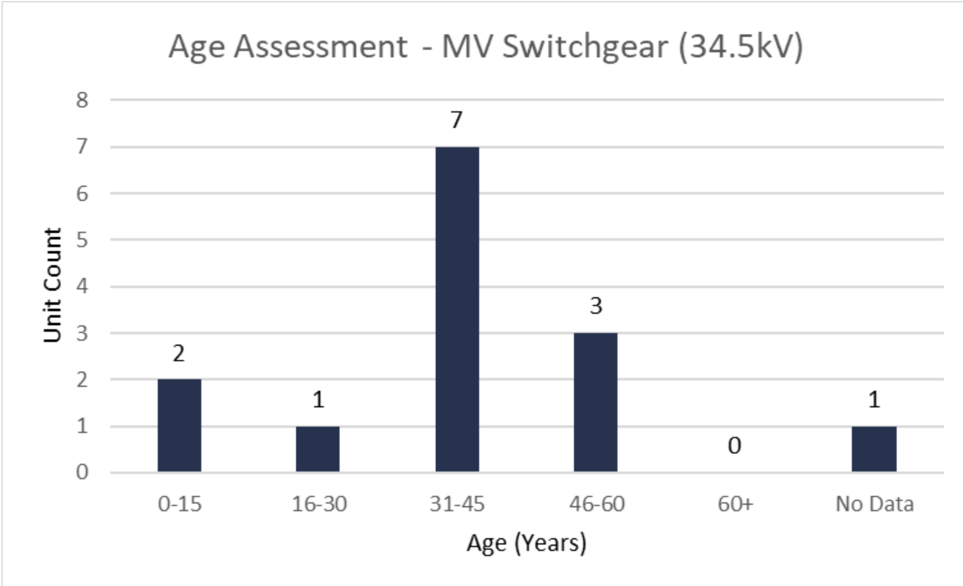


Figure 5.3-35: 34.5kV Substation Switchgear Age Demographics

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

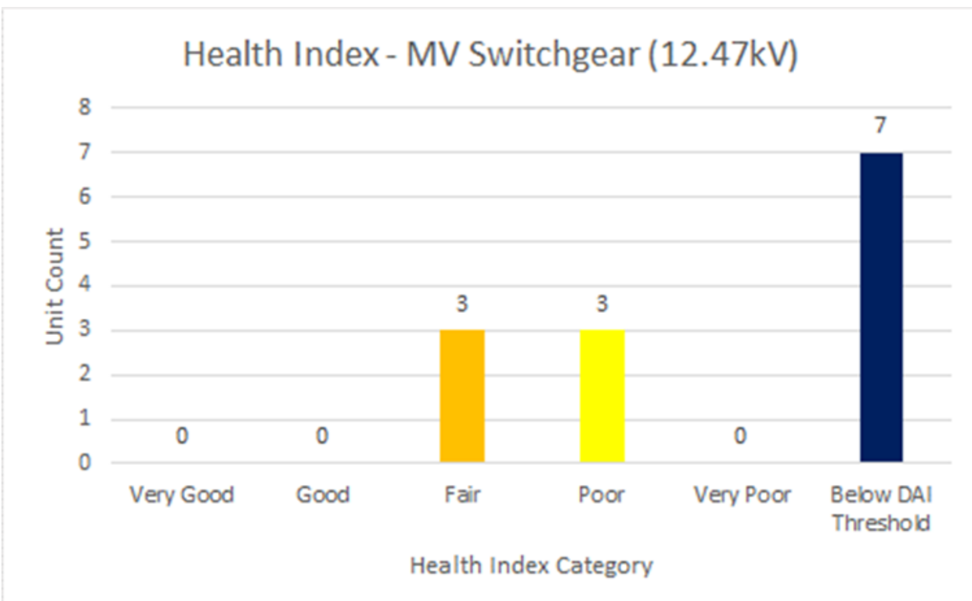


Figure 5.3-36: HI Results – Medium Voltage Switchgear

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

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

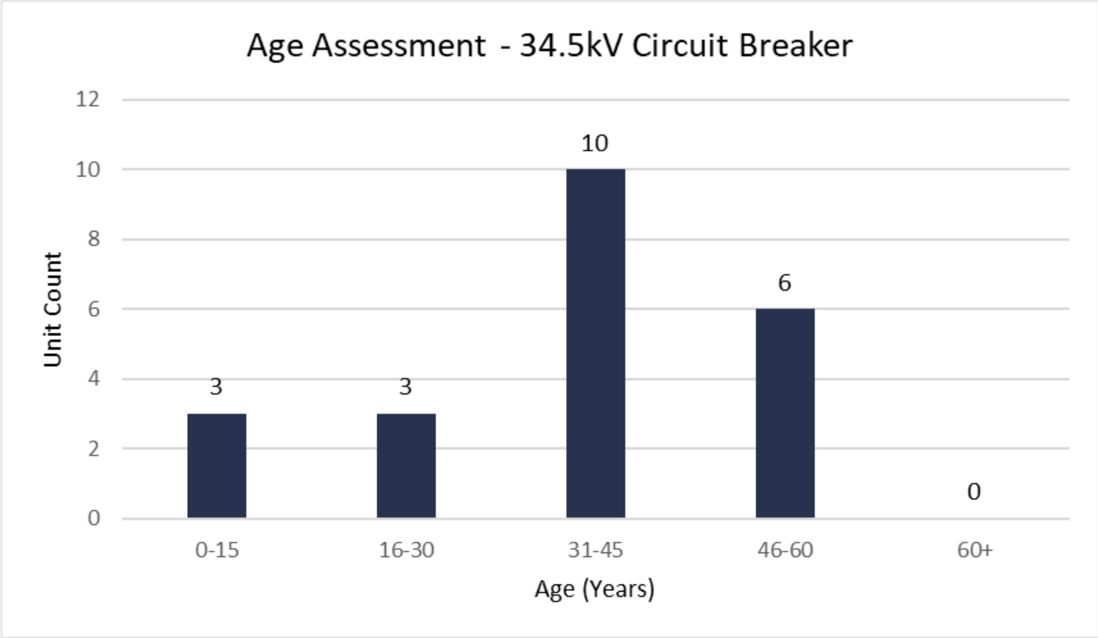


Figure 5.3-37: 34.5-kV TS Circuit Breaker Age Demographics

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

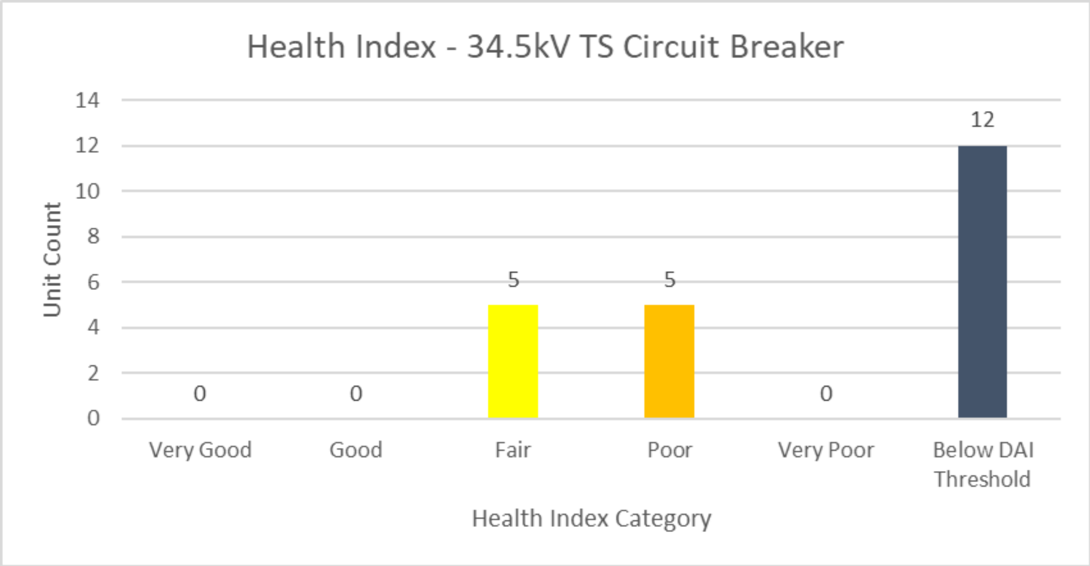


Figure 5.3-38: HI Results – 34.5kV TS Circuit Breaker

Battery Banks and Chargers

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

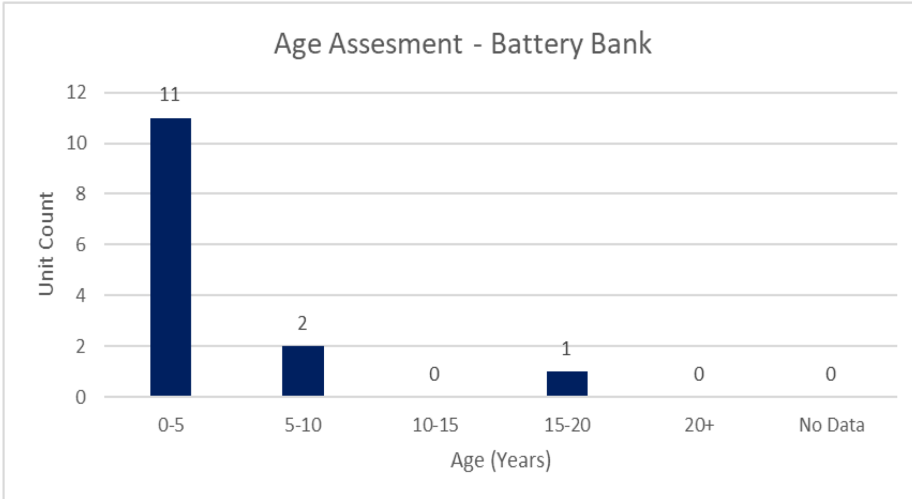


Figure 5.3-39: Substation Battery Banks Age Demographics

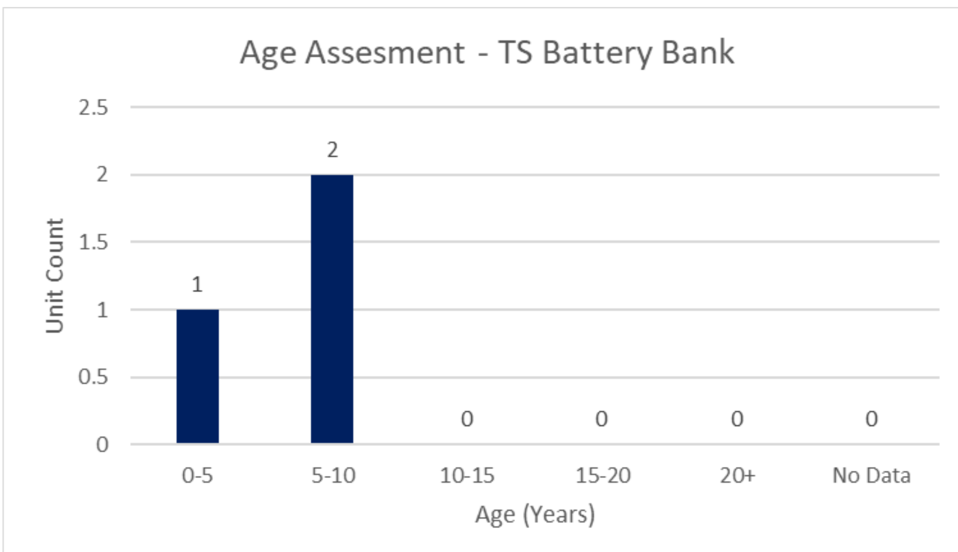


Figure 5.3-40: TS Battery Bank Age Demographics

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

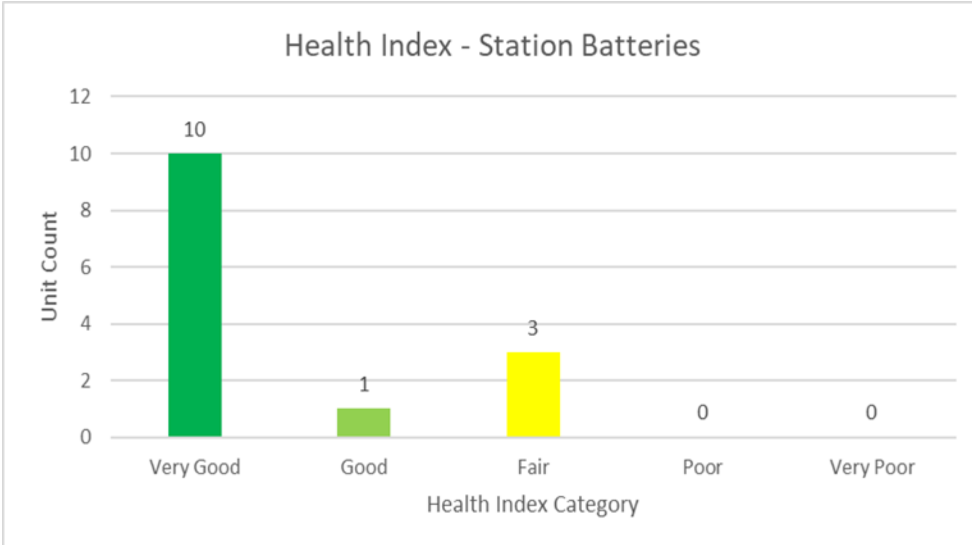


Figure 5.3-41: HI Results – Substation Battery

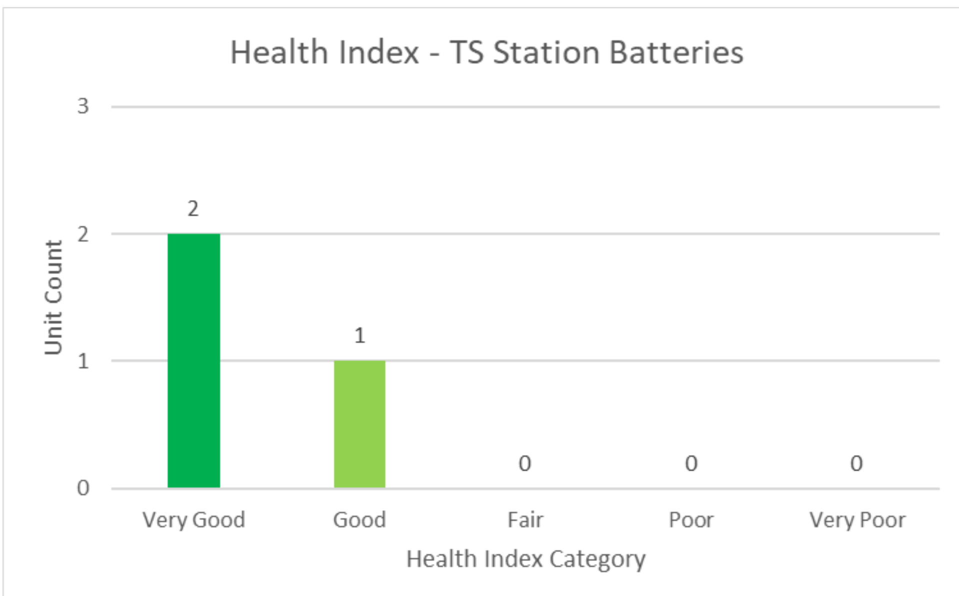


Figure 5.3-42: HI Results – TS Station Battery

<u>Station Buildings</u>

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

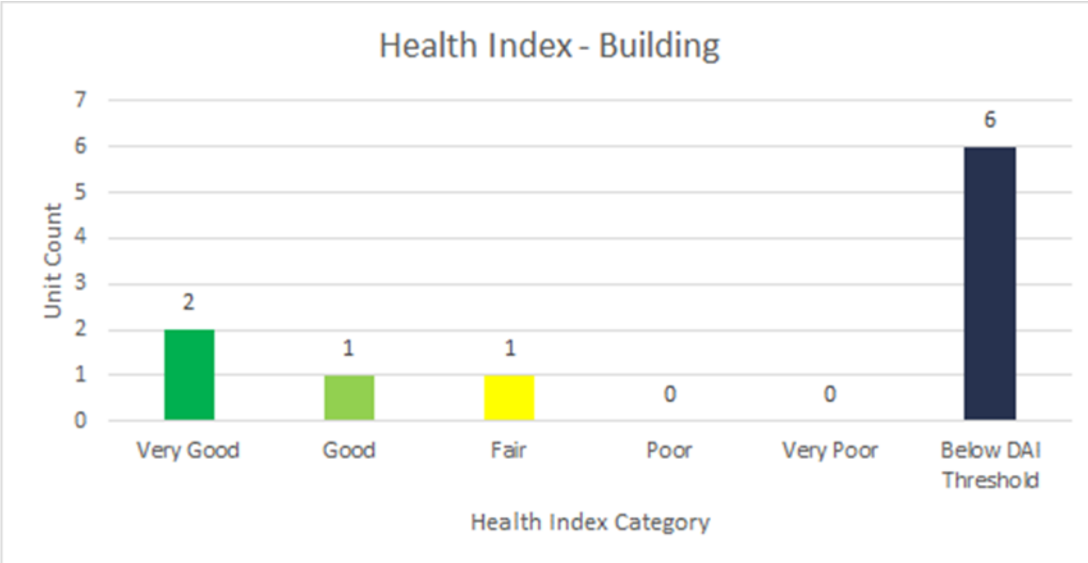


Figure 5.3-43: HI Results – Station Building

<u>Station Fences</u>

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

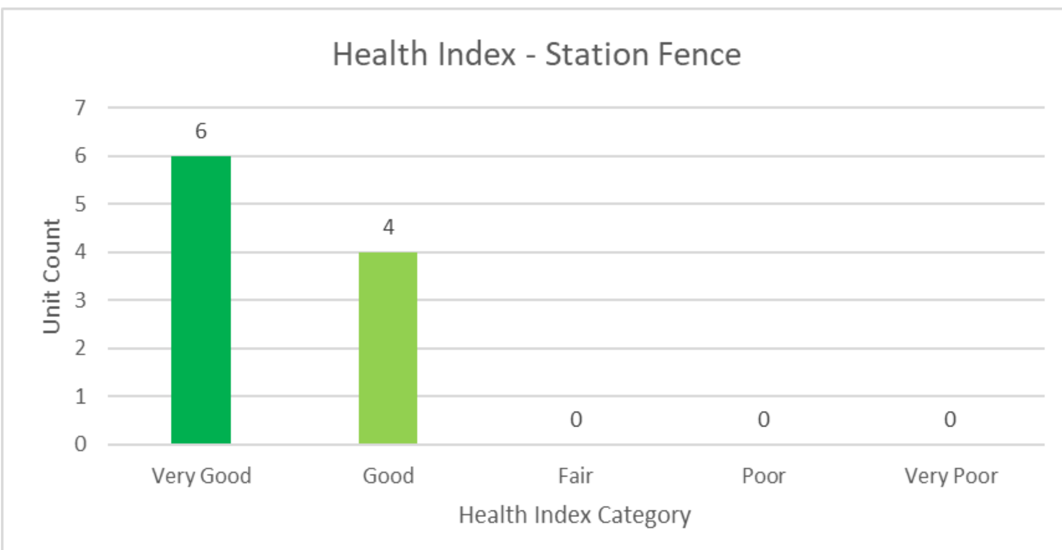


Figure 5.3-44: HI Results – Substation Fence

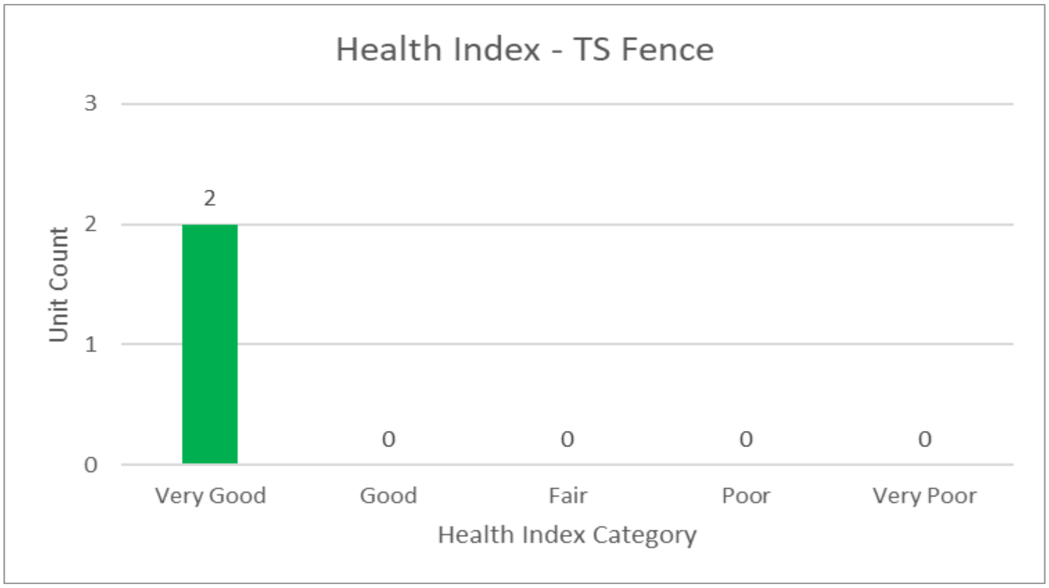


Figure 5.3-45: HI Results – TS Fence

<u>Station Riser Cables</u>

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

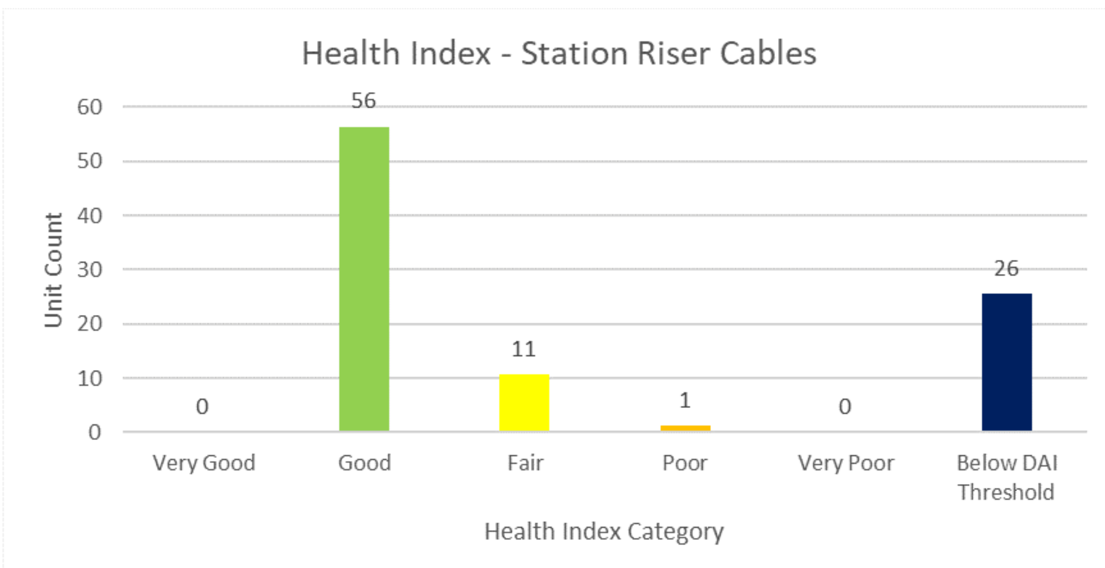


Figure 5.3-46: HI Results – Station Riser Cable

<u>115kV Switches</u>

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

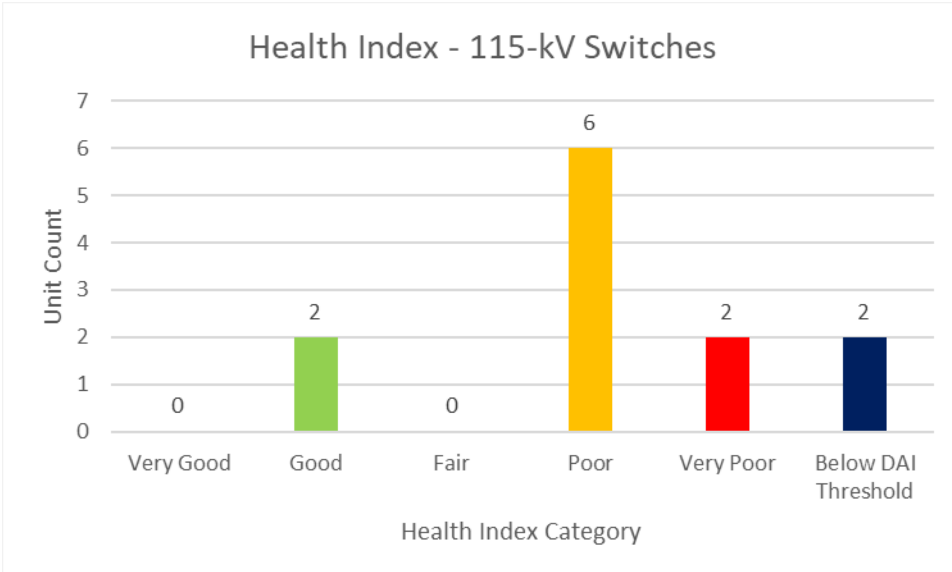


Figure 5.3-47: 115-kV Switches HI Results

5.3.2.2.2.3 Health Index Improvements

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

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

1. Wood Poles

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

Table 5.3-14: Data Collection Recommendation for Wood Poles

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

2. Underground Primary Cables

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

Table 5.3-15: Data Collection Recommendation for Underground Cable

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

3. Pole-mount Distribution Transformers

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

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

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

4. Pad-mount and Submersible Distribution Transformers

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

Table 5.3-17: Data Collection Recommendation for Distribution Transformers

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

5. Underground Switches

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

Table 5.3-18: Data Collection Recommendation for Underground Switches

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

6. Station Power Transformers

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

Table 5.3-19: Data Collection Recommendation for Power Transformers

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

7. Station Riser Cables

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

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

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

5.3.2.2.3 Asset Risks

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

5.3.2.3 Transmission or High Voltage Assets

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

PUC has the following high voltage assets:

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

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

5.3.2.4 Host & Embedded Distributors

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

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

5.3.3 Asset Lifecycle Optimization Policies and Practices

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

5.3.3.1 Asset Replacement and Refurbishment Policy

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

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

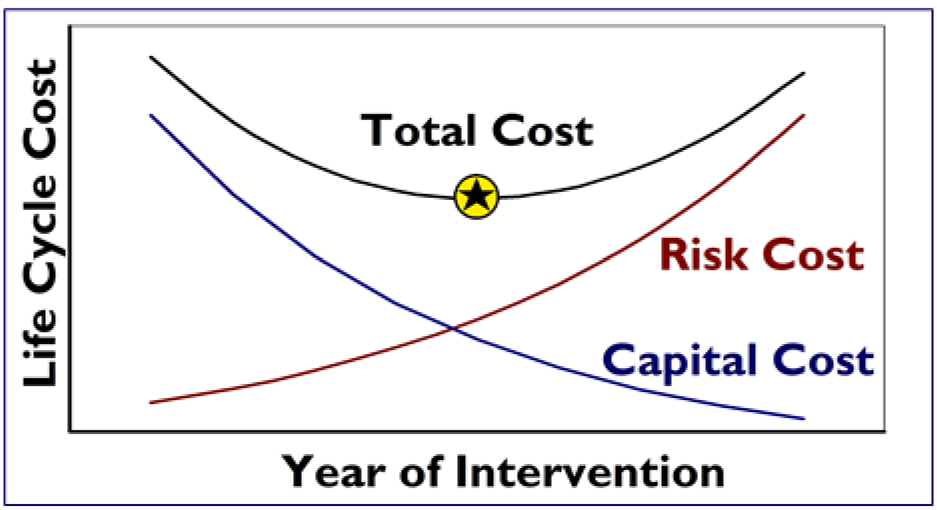


Figure 5.3-48: Risk Based Decision Support System

5.3.3.2 Description of Maintenance and Inspection Practices

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

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

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

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

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

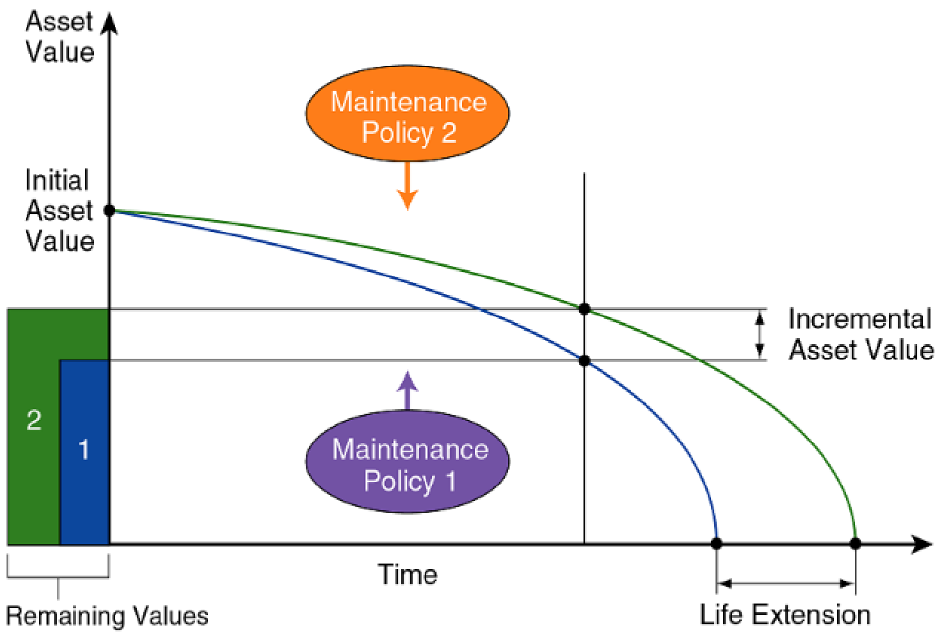


Figure 5.3-49: Risk Based Decision Support System

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

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

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

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

5.3.3.2.1 Preventative Maintenance of Critical Equipment in Substation

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

Table 5.3-21: Substation Preventative Maintenance

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

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

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

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

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

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

5.3.3.2.1.1 Vegetation Management Program

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

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

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

5.3.3.2.1.2 Safety Inspections of Overhead and Underground Distribution Assets

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

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

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

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

5.3.3.3.1 Forecasting

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

An ACA study was carried out by METSCO for PUC to establish the health and condition of distribution and substation assets in service. By taking into account all relevant information related to assets' operating condition, the condition of all infrastructure assets were assessed and expressed on a normalized index in the form of a Health Index (HI). The HI was related to probability of failure values for each project, using a weighted average approach, as described in detail in Appendix H, and each asset was assigned a health indicator expressed as "very good", "good", "fair", "poor" and "very poor." The resulting information from the ACA study was used to help forecast the renewal needs of PUC's assets over the forecast period.

5.3.3.3.2 Prioritization

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

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

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

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

5.3.3.3.3 Optimization

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

The continued performance of assets is also managed through PUC's capital investments and maintenance programs. PUC's inspection, maintenance, and testing practices described previously in Section 5.3.3.2 support asset life cycle risk management by rectifying deficiencies to extend the lives of the assets and identifying the assets in the very worst condition for replacement.

Information obtained through asset registers, maintenance and inspection records and outage records are all critical inputs into prioritizing and in optimizing which projects will bring the best value. For example, PUC can use information from its pole testing program, its annual plant inspection program and reliability statistics, all together, to maximize risk reduction while minimizing cost impacts when addressing end of life and failing poles.

5.3.3.3.4 Strategies for Operating within Budget Envelopes

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

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

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

5.3.3.3.5 Risks of Proceeding / Not Proceeding

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

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

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

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

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

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

5.3.4 System Capability Assessment for REG

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

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

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

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

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

5.3.4.1 Applications for Renewable Generators over 10 kW

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

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

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

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

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

5.3.4.1.1 Applications for REG Generators 10kW or less

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

5.3.4.2 Forecast of REG Connections

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

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

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

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

Table 5.3-23: Five-year REG Forecast

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

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

5.3.4.3 Capacity Available

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

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

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

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

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

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

5.3.4.4 Constraints – Distribution and Upstream

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

5.3.4.4.1 Operational Flexibility

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

5.3.4.4.2 Protection, Control and SCADA

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

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

5.3.4.4.3 Regional Infrastructure Planning

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

5.3.4.5 Constraints – Embedded Distributor

Constraints for an embedded distributor that may result from the connections

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

5.3.5 CDM Activities to Address System Needs

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

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

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

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

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

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

5.3.6 The Sault Smart Grid Project

5.3.6.1 Project Overview

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

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

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

5.3.6.2 OEB Decision and Order

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

Table 5.3-25: SSG Project ICM - OEB Orders

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

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

5.3.6.2.1 PUC’s Response to OEB Order #4

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

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

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

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

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

5.3.6.2.2 PUC's Response to OEB Order #5

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

Project Cost Comparison

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

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

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

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

Table 5.3-26: Sault Smart Grid ICM Reconciliation

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

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

Customer Annual Net Benefit Comparison

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

Table 5.3-27: Customer Annual Net Benefit Summary Comparison

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

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

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

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

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

<u>Other Project Benefits</u>

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

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

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

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

5.3.6.2.3 PUC's Response to OEB Order #6

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

VVO Link to ROE

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

Table 5.3-29: Customer Net Benefit Summary

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

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

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

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

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

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

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

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

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

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

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

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

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

5.3.6.2.4 PUC's Response to OEB Order #9

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

5.4 Capital Expenditure Plan

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

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

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

5.4.1 Capital Expenditure Summary

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

The capital expenditure summary provides a snapshot of PUC's capital and System O&M expenditures over the 2018 – 2027 DSP period. For summary purposes, the entire costs of individual projects have been allocated to one of the four OEB investment categories based on the primary driver for the investment:

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

The breakdown of OEB-approved amounts from PUC's last DSP versus actuals over the historical period by investment category, is provided in Table 5.4-1 and the forecast costs broken down by investment category are provided in Table 5.4-2. Additional details can also be found in the Chapter 2 Appendices 2-AA and 2-AB.

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

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

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

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

5.4.1.1 Plan vs Actual Variances for the Historical Period

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

Assessing and understanding the variances is an important step for PUC to promote continuous improvements in its estimation and budgeting process. Excluding projects identified as mandatory, PUC creates each project budget based on preliminary designs and historical costs for planning its programs annually. Once detailed designs are complete and ready to be issued for construction, the project estimate is revised to reflect any changes in the design. The revised estimate is used to track against the actual costs, which are reviewed monthly. Customer demand projects are budgeted using averages from previous years. These projects are mostly unplanned and tracked in real-time to balance the total annual budget with other discretionary projects (i.e., PUC may take action to reduce system renewal projects to ensure the total annual actual expenditures remain in line with the total annual proposed budget). Likewise, if the actual budget of system access projects is less than the forecasted budget, PUC may plan to allocate the budget to other system access planning years or to other project categories where appropriate to maintain consistent annual expenditures.

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

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

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

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

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

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

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

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

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

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

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

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

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

5.4.1.2 Forecast Expenditures

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

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

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

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

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

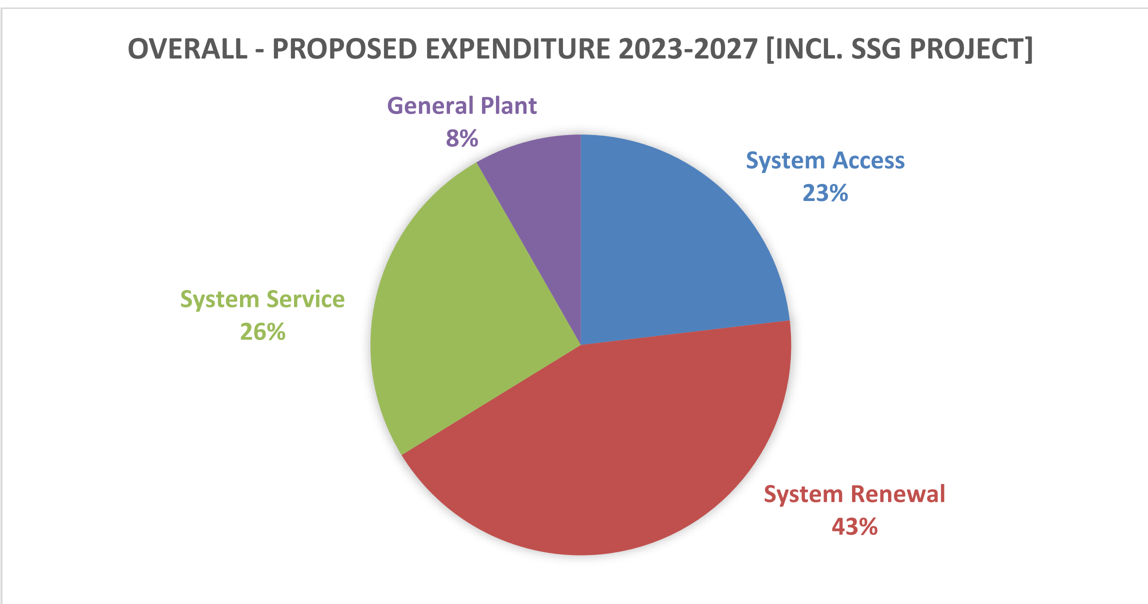


Figure 5. 4-1: Forecast Net Capital Expenditures Ratio [Incl. SSG Project]

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

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

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

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

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

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

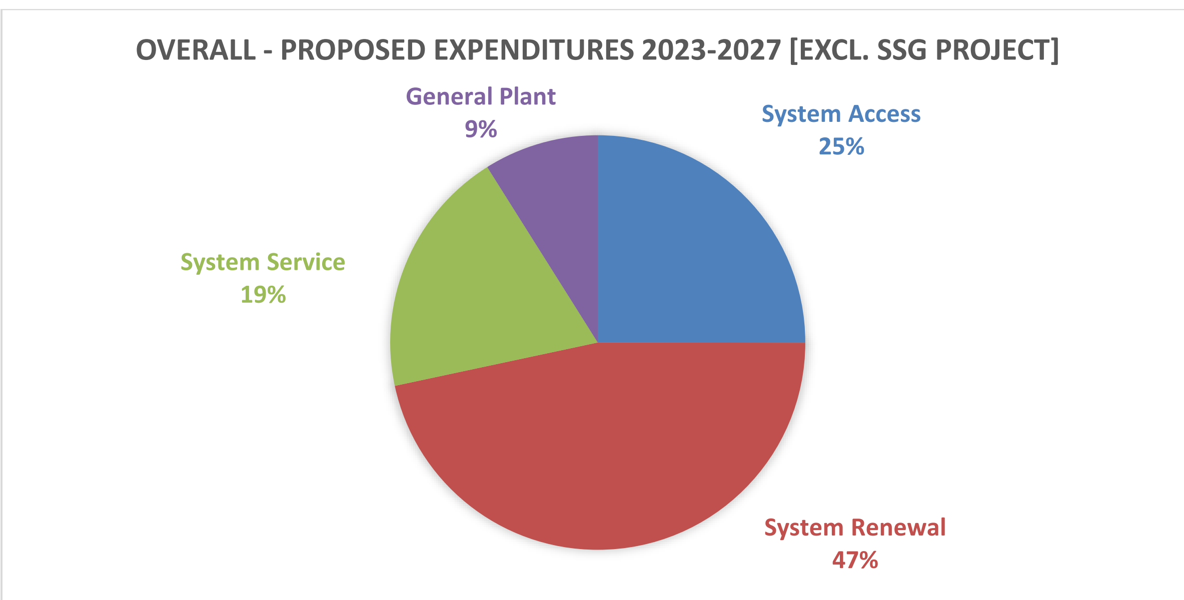


Figure 5.4-1: Forecast Net Capital Expenditures Ratio [Excl. SSG Project]

5.4.1.2.1 System Access

Expenditures within the system access category are largely driven by customer service requests for new connections and/or service upgrades, and mandated service obligations. The timing of investments in this category are driven by the needs of external parties and are considered mandatory. Investments in system access are captured in the following table and figure.

Table 5.4-10: Forecast Net System Access Expenditures

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

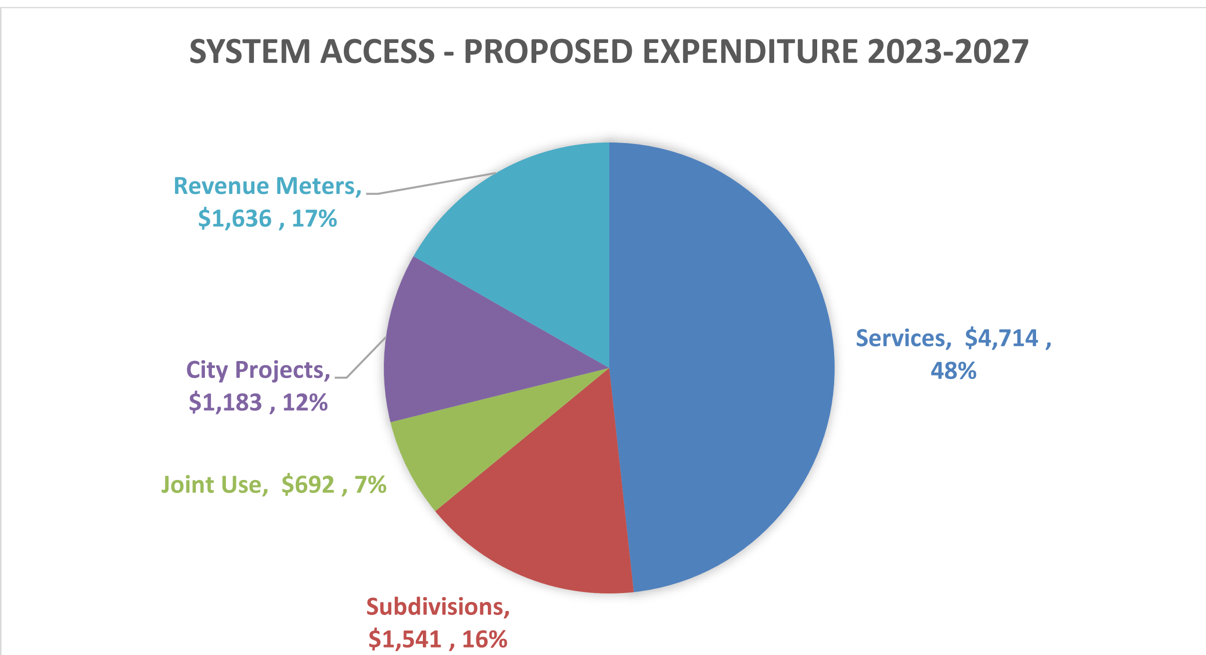


Figure 5.4-2: Forecast Net System Access Expenditures Ratio

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

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

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

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

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

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

5.4.1.2.2 System Renewal

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

Table 5.4-11: Forecast Net System Renewal Expenditures

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

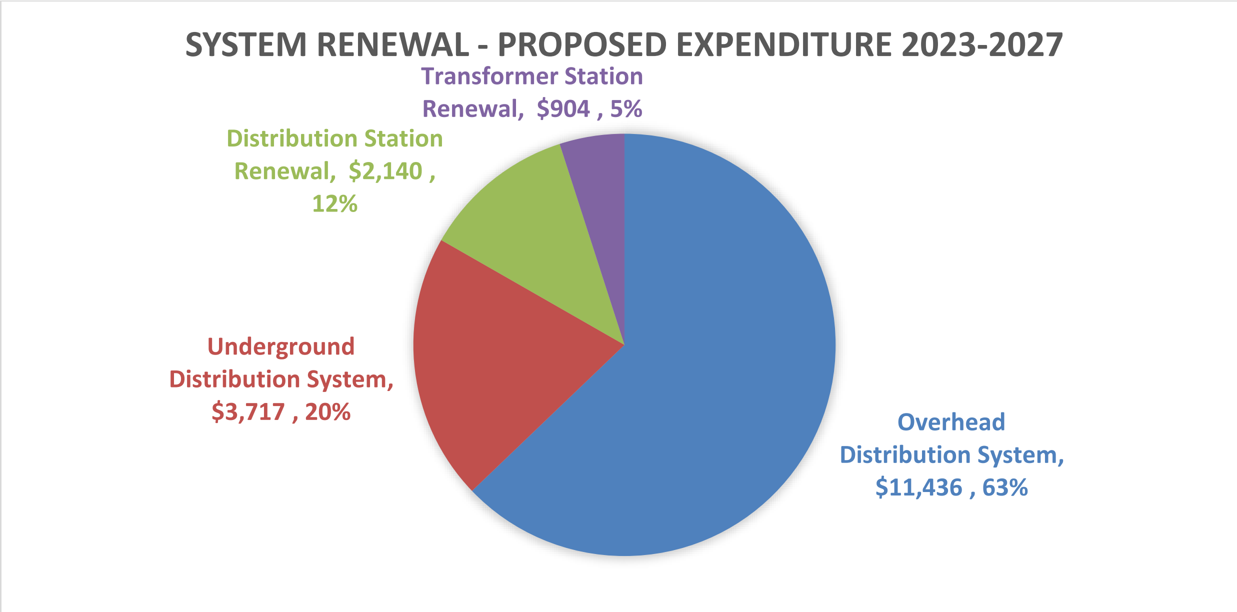


Figure 5.4-3: Forecast Net System Renewal Expenditures Ratio

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

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

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

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

The level of investments required over the forecast period was determined using PUC's AM process, which is described in detail in Section 5.3 It is noted that priority of investment has been given to assets where strong ACA data is available such as deteriorated poles, distribution transformers and restricted conductor. For assets where ACA data was limited, such as underground cables, station riser cables and distribution and transmission station assets, only smaller investments are proposed for critical assets, and further studies and testing are included in the next five year plan to better quantify the investment needs in these areas. Some specific initiatives planned in the next five years to address these gaps are the establishment of a formal buildings and facilities asset management plan, a transmission station study to determine a course of action for stations TS-1 & TS-2, and expenditure allotted to partial discharge testing of critical direct buried, radial feed cables. PUC will continue to further review its testing and data gaps and put in place additional plans to address these gaps as required.

The year over year fluctuations and overall decrease in system renewal spending over the forecast period is partly driven by the completion of some of PUC's key system renewal investments including the voltage conversion program in 2023 and the replacement of distribution transformers with PCB >50ppm in 2025. The observed decrease is also partially driven by the need to accommodate and balance the increased level of investments required under other investment categories (i.e., System Service). Year over year fluctuations are also impacted by the availability of resources and contractors.

5.4.1.2.3 System Service

System service investments are modifications to PUC's distribution system to ensure the distribution system continues to meet PUC operational objectives (system efficiency, power quality etc.) while addressing anticipated future customer electricity service requirements. Investments in system renewal are captured in the following table and figure.

Table 5.4-12: Forecast Net System Service Expenditures [Incl. SSG Project]

Category	Forecast					Total ($ '000)	Percent of Total
	2023	2024	2025	2026	2027		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Capability – DX Station Build	-	-	324	409	4,904	5,637	52%
Expansions – 34.5 kV OH Lines	-	-	518	341	955	1,814	17%
Expansions – 34.5 kV UG Lines	-	127	-	-	-	127	1%
SSG Project	3,190	-	-	-	-	3,190	30%
Total Expenditure, Net	**3,190**	**127**	**841**	**750**	**5,859**	**10,768**	**100%**

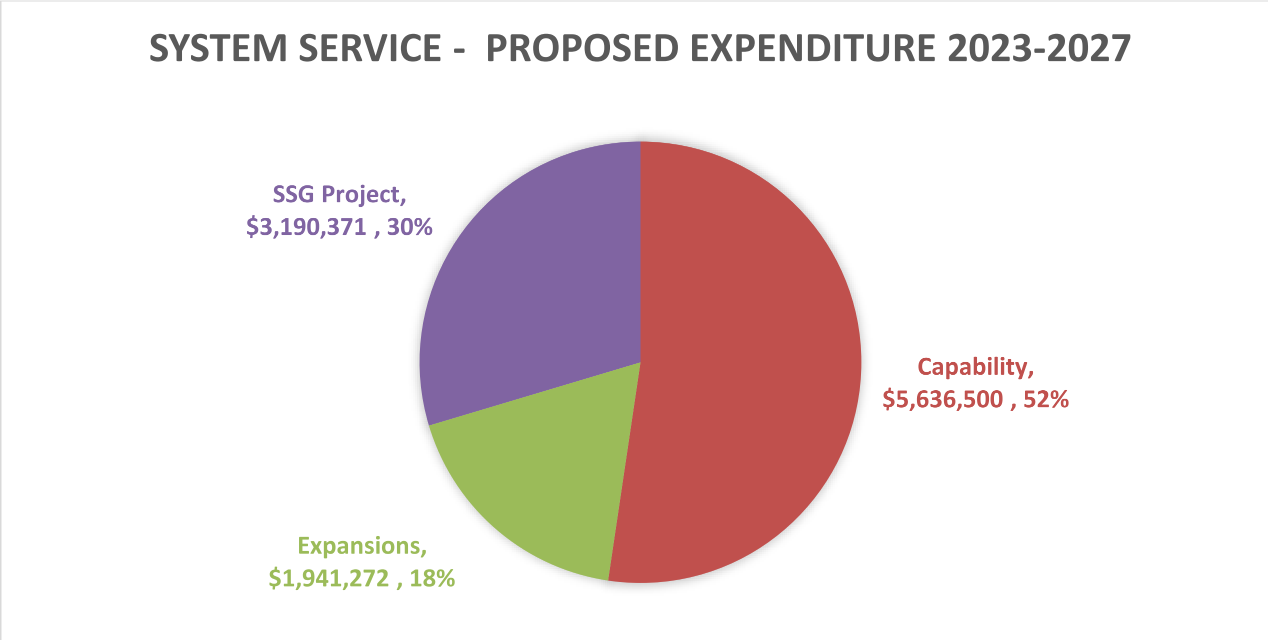


Figure 5.4-2: Forecast Net System Service Expenditures Ratio [Incl. SSG Project]

When including the SSG Project, system service investments represent 26% of PUC's overall budgeted net capital expenditures over the forecast period. Within this category, 52% of the expenditures are associated with Capability, 30% are associated with the SSG Project, and the remaining 18% is associated with Expansions.

The capability costs relate to a new distribution station build (Substation 22 due to be built in 2027) that is proposed to accommodate the localized shift in demand occurring in the westerly portion of PUC's service territory which is being driven by requests for connection of several large and medium sized commercial customers. Additional information on this investment can be found in Section 5.2.1.4.

The costs associated with OH and UG expansions are attributable to costs to construct a new 34.5 kV express feeder tie between PUC's two 115kV/34.5kV transformer stations TS-1 and TS-2. The ability to transfer load between these two critical transformer stations is currently limited. The project will help reduce the potential impacts of a TS component failure and allow the transfer of load promptly during a failure event. As mentioned elsewhere in this application and in the ACA, TS-1 and TS-2 are expected to approach a critical point for replacement in the next five to 15 years and a plan for renewal withing that time horizon is being pursued. The proposed 34.5 kV express feeders will serve as a reliability bridge to see customers through until the larger proposed TS renewal becomes cost effective.

When excluding the SSG Project costs, the ratio of system service expenditures decreases to 19% of overall budgeted net capital expenditures over the forecast period, and approximately two thirds of the expenditures within this category are associated with capability, with the remaining third towards OH and UG expansions, as shown in Figure 5.4-4.

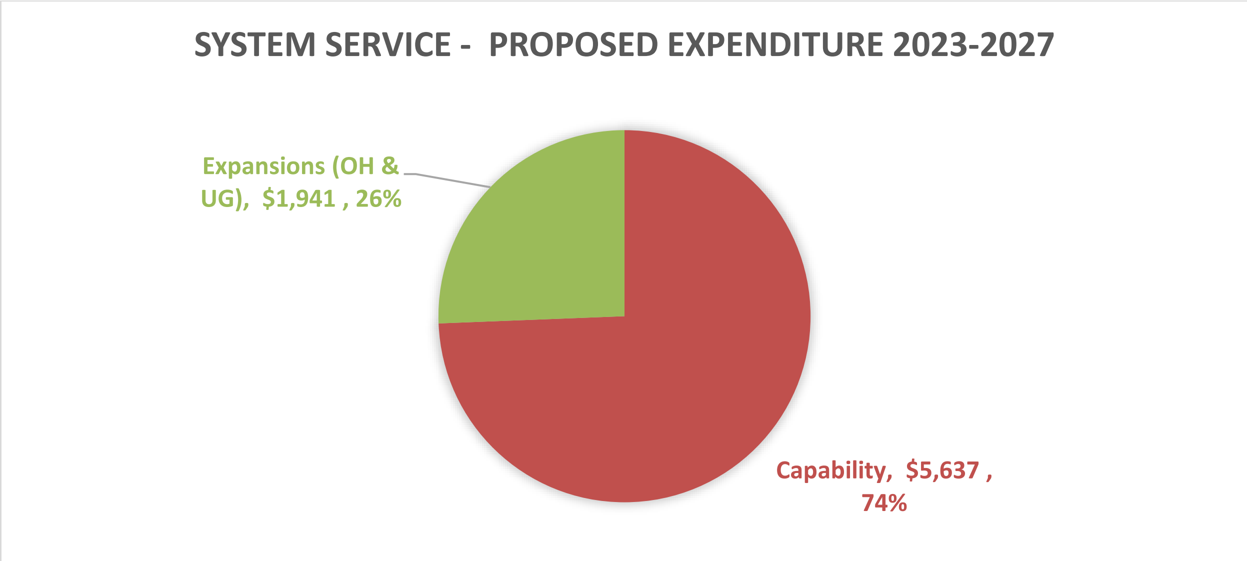


Figure 5.4-4: Forecast Net System Service Expenditures Ratio [Excl. SSG Project]

5.4.1.2.4 General Plant

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

Table 5.4-13: Forecast Net General Plant Expenditures

Category	Forecast					Total ($ '000)	Percent of Total
	2023	2024	2025	2026	2027		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Tools & Equipment	295	38	188	-	-	521	15%
Distribution IT	44	483	580	71	41	1,219	35%
Buildings	238	293	265	361	592	1,750	50%
Total Expenditure, Net	**577**	**813**	**1,033**	**432**	**633**	**3,489**	**100%**

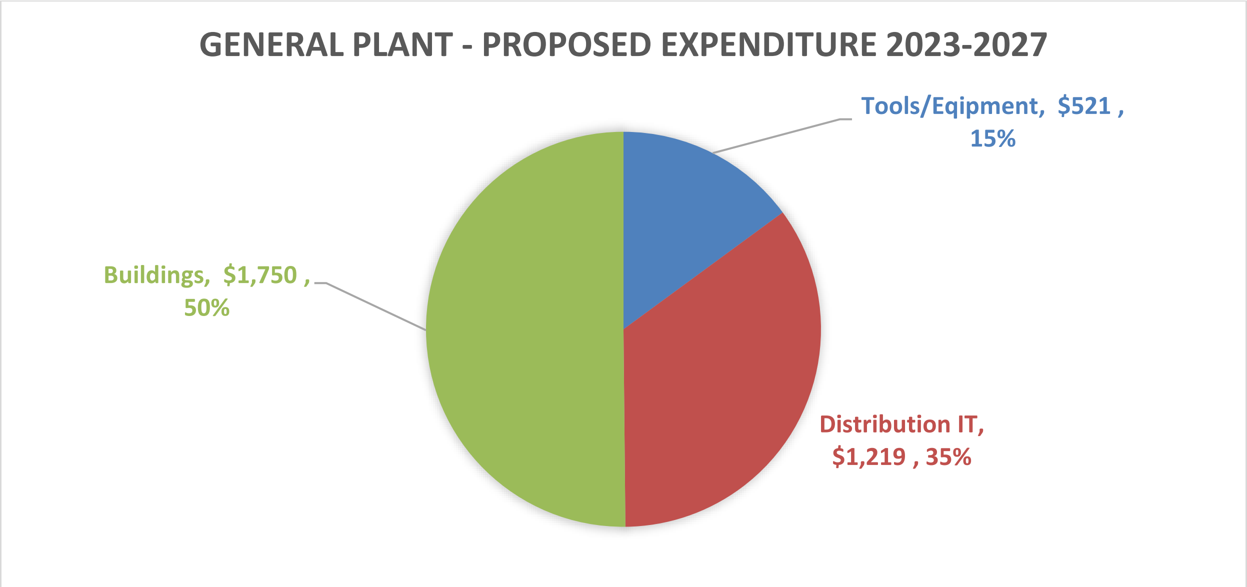


Figure 5.4-5: Forecast Net General Plant Expenditures Ratio

General plant investments represent 8% of PUC's overall budgeted net capital expenditures over the forecast period (or 9% when excluding the SSG Project costs). Representing the largest portion (50%) of the expenditures within this category, Buildings involve the renewal and upkeep of PUC's main facility, which represents the critical backbone of PUC's 24/7 operations. Ongoing Building investments are proposed over the forecast period to ensure safe and reliable continuation of PUC's operations.

Distribution IT, which represents the second largest driver within this category at 35%, is primarily driven by PUC's GIS Utility Network (UN) Migration project planned for 2024/25. PUC's existing GIS is based on Geometric Network technology, which is approximately twenty-five years old, approaching end of useful life, and will no longer be supported by the vendor in the next three years as they move exclusively to a UN platform. Migration to the new platform, including all of PUC's existing asset information and custom developed applications is expected to take two years. Additional information on the GIS UN Migration project can be found in Section 5.4.2.1.1.

The remaining 15% of expenditures in this category is allocated towards tools/equipment, which involves planned investments in tools/equipment to help improve PUC's testing and inspection regimes.

The year over year fluctuations observed in forecast general plant spending are primarily being driven by the SSG Project. The SSG Project timing and resource requirements have resulted in the deferral of the GIS UN Migration project to a 2024/25 implementation timeframe, which explains the overall increase in general plant spending during these years. Following completion of the GIS UN Migration project, PUC expects the Distribution IT spending to return to traditional levels of spending. The other more minor fluctuations observed under tools/equipment and buildings are driven by one-time costs associated with the replacement of larger and more expensive equipment (i.e., oil drying unit and compressor/chiller pump replacements).

5.4.1.2.5 Investments with Project Lifecycle Greater than One Year

For capital investments that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress.

For capital projects spanning multiple years, costs remain under construction work-in-progress (WIP) until the capital project is in service. Therefore, capitalization will only occur at the end of the project once it is in service.

Two examples of multi-year capital projects proposed over the forecast period include the GIS UN Migration project and the new distribution station build (Sub 22). In each case, although the project costs span multiple years, costs will remain under WIP throughout the execution of the project and will only be capitalized once in service.

5.4.1.3 Comparison of Forecast and Historical Expenditures

An analysis of capital expenditures in the DSP's forecast period as compared to the historical period.

A comparison of PUC's net capital expenditures over the forecast period as compared to the historical period is provided in the following sub-sections.

5.4.1.3.1 System Access

The historical system access trend is variable year over year due to the unpredictability of customer connection service requests and other external factors. As shown in Figure 5.4-6, PUC's system access forecast average expenditures are approximately 22% greater than the historical plus bridge year average. This proposed increase is attributable to two factors. Firstly, in 2022, PUC began experiencing a ramping up of residential and commercial development in the community not seen in over a decade. Through consultations with the City, developers, consultant and contractors, PUC has updated their projections for the forecast period to reflect that this trend which is expected to continue for the next three to five years. Secondly, slightly elevated activity in the area of joint use projects is expected, as the provincial government moves forward with initiatives to expand broadband access across the province.

Historically, an increasing trend in system access costs is observed from 2018 to 2020, followed by a declining trend from year 2020 to year 2022. This is explained by a combination of two factors. Firstly, there was a surge in the area of joint use activity 2018 through 2020 as one of the major telecom utilities in the service territory implemented their 'fibre to the home' initiative. The increase in spending was primarily attributable to the make-ready work associated with this project. This investment, however contributed to renewal of infrastructure that was approaching end of life and did so with partial capital contributions in accordance with joint use agreements, bringing added benefit for ratepayers. The subsequent decline in expenditures in 2021 and 2022 is reflective of the return to more typical historical levels, somewhat dampened by a slowdown in customer connections due to the COVID-19 pandemic.

The temporary increase in forecast costs observed between 2023-2025 can be attributed to the required costs associated with Joint Use projects and MIST meter installations. However, following the completion of these projects, system access costs are expected to return to more standard costs adjusted for inflation.

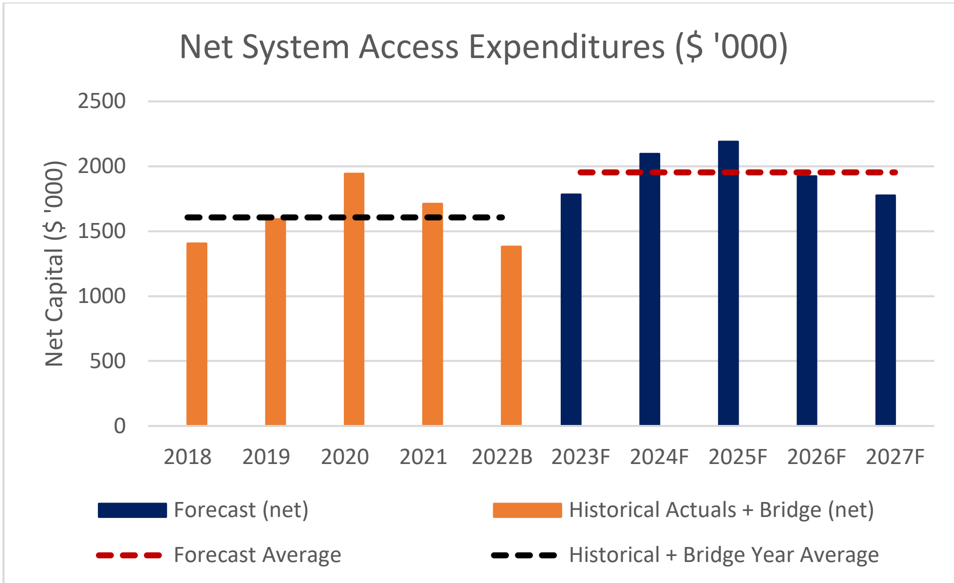


Figure 5.4-6: System Access Comparative Expenditures

5.4.1.3.2 System Renewal

As shown in Figure 5.4-7, PUC's forecast average for system renewal is 28% lower than the historical plus bridge year average. This is primarily as a result of the significant historical spending associated with the following projects:

- The large jump in 2021 is due to the $6.02M spend associated with PUC's Substation 16 ICM (EB-2019-0170). The actual cost for implementation of this project ($6.02M) was above the amount approved at the time of the ICM application ($4.73M) due to inflation in material and labour costs available at the time of construction.
- The jump in 2022 is primarily driven by a $2.7M spend associated with the renewal of six distribution station transformers and primary switchgear at three of PUC's substations that were purchased in support of the SSG Project. Although these investments were not originally planned for 2022, they were identified as having warranted asset renewal needs and received higher priority as a result of their alignment with the SSG Project.

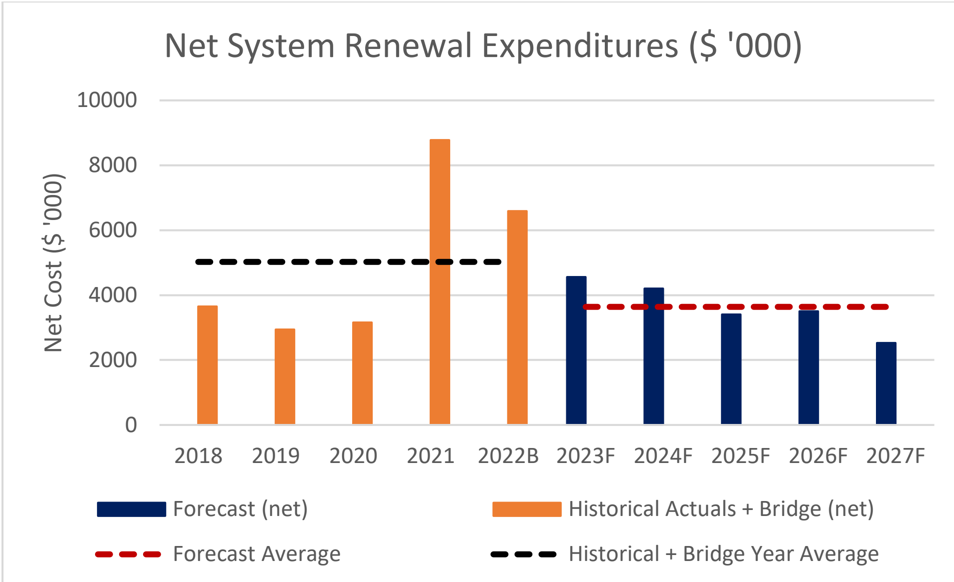


Figure 5.4-7: System Renewal Comparative Expenditures [Incl. Sub 16 ICM]

The timing and magnitude of Substation 16 was not finalized at the time of the previous COS filing, and an ICM application was required and approved by the OEB. When excluding the costs associated with PUC's Substation 16 ICM project, the forecast average for system renewal is 5% lower than the historical plus bridge year average, as shown in Figure 5.4-8.

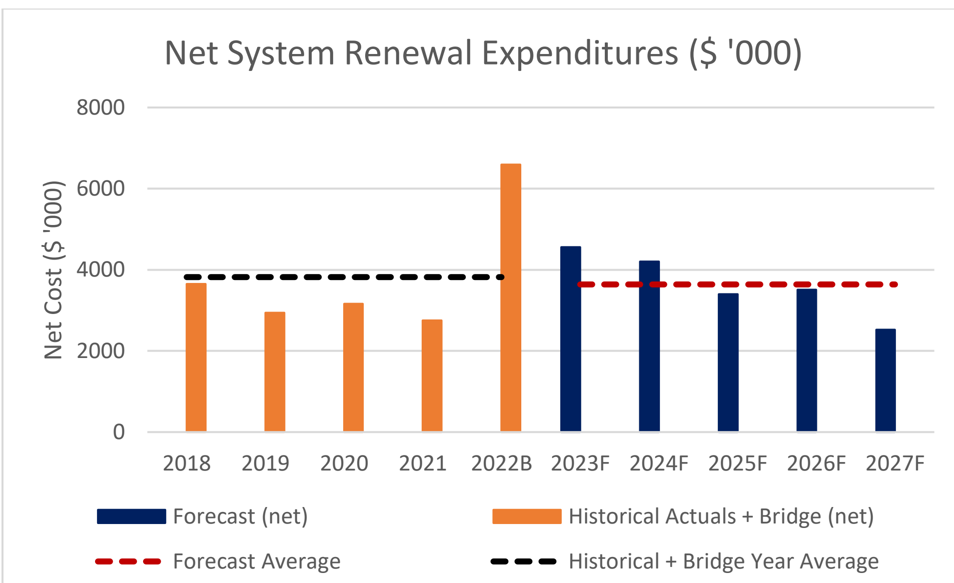


Figure 5.4-8: System Renewal Comparative Expenditures [Excl. Sub 16 ICM]

The observed decrease in forecast system renewal spending is partially driven by the need to accommodate and balance the increased level of investments required under other investment categories over the forecast period. At the same time, the level of forecast system renewal spending is reflective of the ongoing efforts needed in asset renewal to keep pace with recommendations identified in the ACA, while staying in step with customer preferences for maintaining costs, reliability, and service levels status quo.

5.4.1.3.3 System Service

As shown in Figure 5.4-9, PUC's forecast average for system service is approximately 50% lower than the historical plus bridge year average. This is primarily as a result of the significant spending associated with SSG Project, which has a net capital cost of $21.36M in 2022 and $3.19M in 2023.

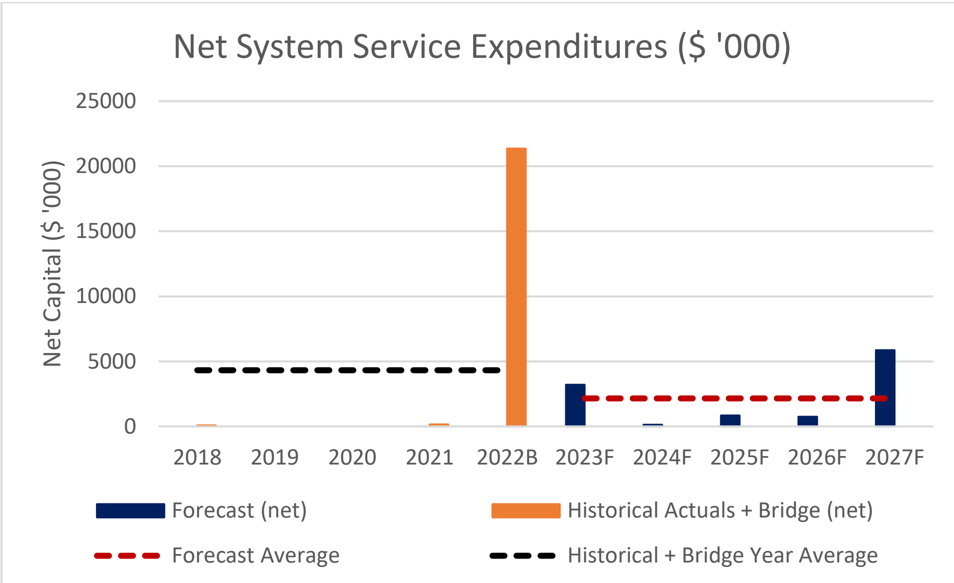


Figure 5.4-9: Net System Service Comparative Expenditures [Incl. SSG Project]

When excluding the SSG Project cost, PUC's forecast average for system service is approximately 3,238% greater than the historical plus bridge year average, as shown in Figure 5.4-10. This increase is driven by the new distribution station build in 2027 to mitigate the capacity constraints in the western part of PUC's service territory.

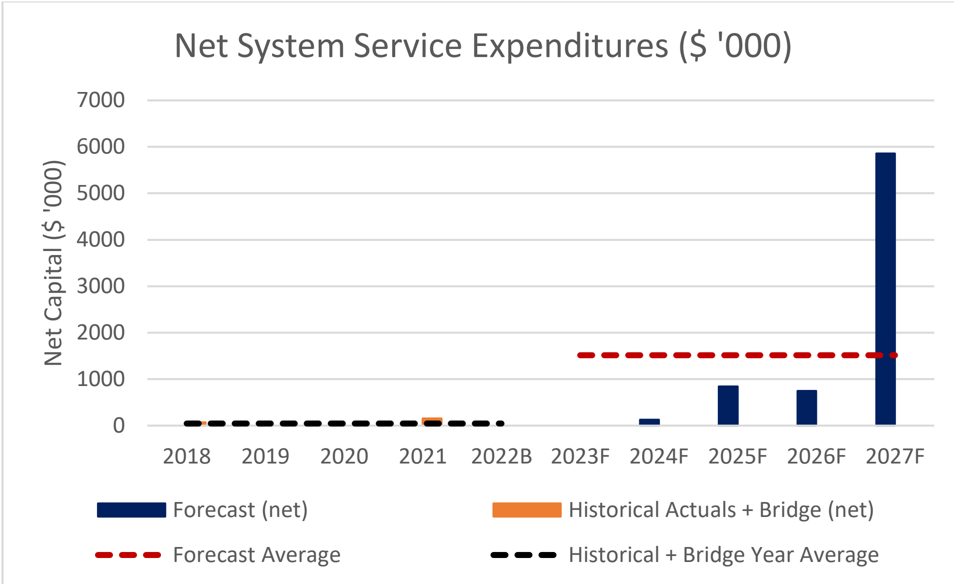


Figure 5.4-10: Net System Service Comparative Expenditures [Excl. SSG Project]

5.4.1.3.4 General Plant

As shown in Figure 5.4-11, the forecast average for general plant is approximately 280% higher than the historical plus bridge year average. This is primarily due to increased renewal investments required in buildings, tools & equipment over the forecast period, and the GIS UN Migration project planned for 2024/25.

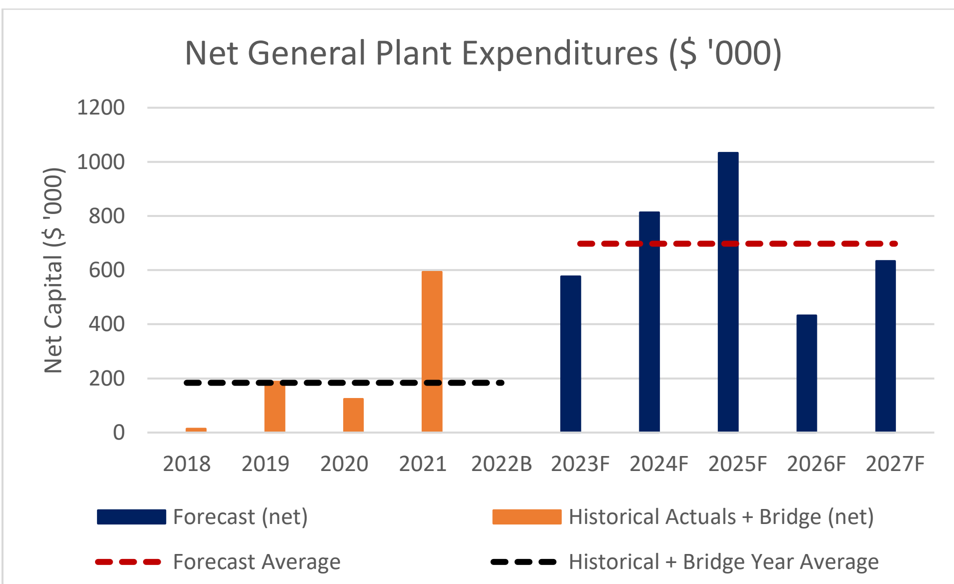


Figure 5.4-11: General Plant Comparative Expenditures

5.4.1.3.5 Overall Capital Expenditures

The overall net capital expenditure trends over the 2018 to 2027 period, including PUC's two ICM projects, are shown in Figure 5.4-12. The average overall capital expenditures forecast is approximately 24% lower than the historical plus bridge year average. This is largely as a result of the costs associated with the Substation 16 ICM and SSG Project ICM.

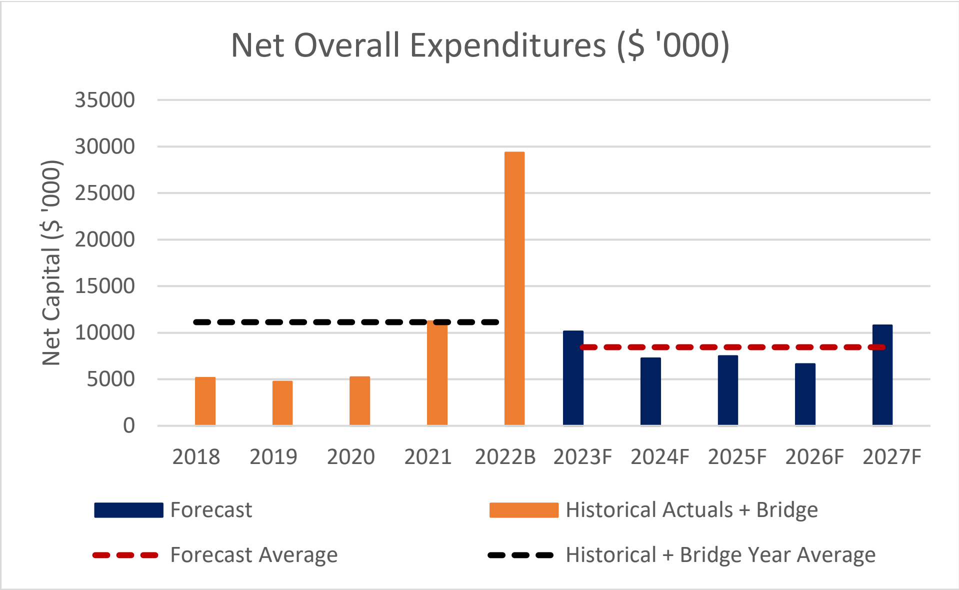


Figure 5.4-12: Overall Comparative Expenditures [Incl. Sub 16 ICM & SSG Project ICM]

When comparing overall net expenditures over the historical and forecast periods, it is important to compare expenditures on an apples-to-apples basis. Since the SSG Project is not considered to be part of PUC's normal capital expenditures, these costs should be removed to provide the OEB and interveners with a more representative comparison of the forecast expenditure compared to historical expenditures.

On the other hand, although significant substation renewal projects and new builds tend to be more costly and less frequent, they are still an expected capital expenditure for any LDC that owns, maintains and operates distribution substations. As a result, PUC's historical and forecast substation investments should both be included in the comparison of overall expenditures.

When excluding the SSG Project costs, the average overall capital expenditures forecast is approximately 14% greater than the historical plus bridge year average, corresponding to an annualized increase of 2.65%.

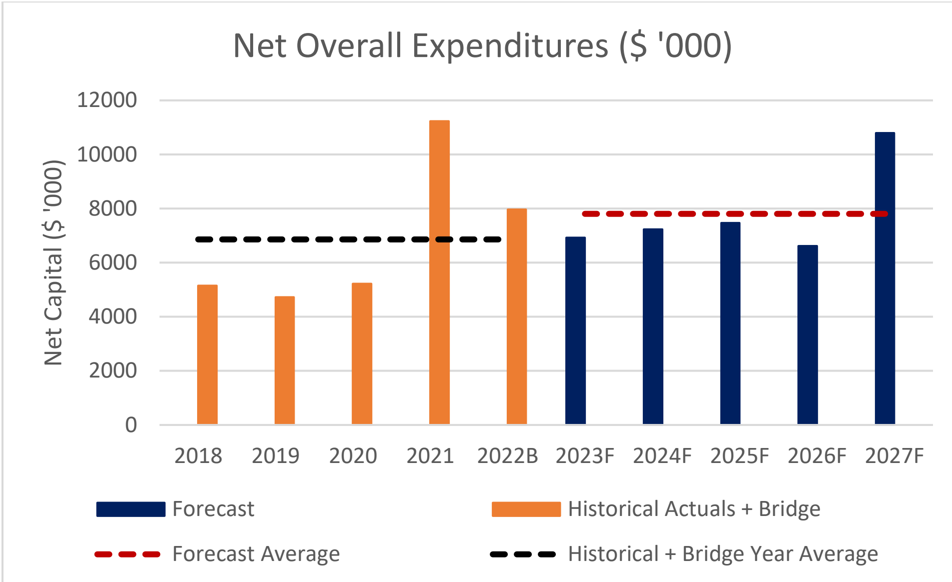


Figure 5.4-13: Overall Comparative Expenditures [Excl. SSG Project ICM only]

Given the rising cost of goods and services required to complete the forecast work, a 14% increase (or 2.65% annualized increase) over the forecast period is considered to be quite modest. This modest increase reflects the increase in system access due to anticipated development in the community, an increase in system service to mitigate the capacity constraints in the western part of PUC's service territory, and an increase in general plant required to maintain and upgrade PUC's buildings, tools & equipment and GIS system.

It should also be noted that, at the direction of the OEB, the SSG Project was accommodated through the re-prioritization of other capital expenditures. If the SSG Project did not occur, there would have been other capital expenditures in its place, so the 2022 and 2023 capital expenditure levels shown in Figure 5.4-13 may not be entirely accurate of what the 2022 and 2023 expenditures would have looked like without the SSG Project.

5.4.1.4 Forecast Impact of System Investments on System O&M Costs

System O&M costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. A distributor is expected to consider the reduction in O&M costs when planning capital investments. A description of the impacts of capital expenditures on O&M must be given for each year, or a statement that the capital plans did not impact O&M costs. A distributor must consider the trade-offs between capital and O&M when assessing alternative options to a capital investment.

Table 5.4-14 summarizes the forecast system O&M spending over the forecast period.

Table 5.4-14: Forecast System O&M Expenditures

Category	Forecast ($ '000)				
	2023	2027	2025	2026	2027
System O&M	7,280	7,644	8,026	8,428	8,849

Although PUC’s forecast capital investments are not expected to reduce system O&M costs, they are expected to prevent System O&M costs from growing over time above regular inflation. Efficiencies achieved in some areas are expected to offset growing O&M needs in other areas as assets continue to age. Based on the ACA findings, and to respect customer preferences to maintain costs and service levels, the forecast level of capital investment has been carefully set with a goal of maintaining system O&M expenditure requirements.

5.4.1.5 Non-Distribution Activities

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

There are no expenditures for non-distribution activities in PUC’s budget.

5.4.2 Justifying Capital Expenditures

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor’s rate proposal is based.

Customer Value

Filings must enable the OEB to assess whether and how a distributor’s DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate optimization, prioritization and pacing of capital-related expenditures.

Customers represents one of the three areas of strategic focus at the centre of PUC’s five-year Strategic Plan, and meeting customers’ needs and expectations is one of PUC’s AM objectives. These key inputs and objectives drive PUC’s planning and AM processes, and customer feedback is a key input considered when developing capital plans.

By prioritizing system access projects, including new customer connections, service requests, new subdivisions, City projects, and joint use projects, as mandatory, PUC ensures that customer needs and requests are being met.

The scope of capital investments planned in the system renewal category has also been determined with the objective of keeping power supply reliability from deteriorating below an acceptable level while also keeping the overall investment envelope for this DSP within a range which would not result in retail rates escalations beyond the affordability of PUC’s customer base. This is in alignment with the top two customer priorities identified in a recent survey, which corresponds to the delivery of reasonably priced electricity services and ensuring safe and reliable electricity services.

The proposed system service investments deliver value to customers by mitigating capacity constraints in the western part of PUC’s service territory, thereby allowing the connection of several large and medium sized commercial customers, which in turn will help drive economic growth within the region. PUC’s general plant investments are also selected and prioritized such that PUC can continue to operate safely, efficiently and support other work.

Customer value per dollar spent is also one of the refinement criteria considered as part of PUC’s prioritization process, which is detailed further in Section 5.3.1.3.

The SSG Project will also deliver direct benefits to customers through reduction in energy consumption and monthly bills, reliability improvements, and improved planning and data reporting systems, and will also deliver significant, direct GHG emissions reductions.

Technological Changes and Innovation

A distributor should also keep pace with technological changes.

There are several ongoing and proposed innovative projects that PUC is undertaking to address current issues including grid modernization, distributed energy resources (DERs) integration and climate change adaptation. The following activities are being undertaken at PUC:

- **SSG Project** – The SSG project is a community wide smart grid which will cover PUC's entire service territory. The SSG project is expected to transform PUC's entire distribution system through an integrated project implementing the following technologies:
    - Voltage/VAR Optimization: allows a utility to operate its distribution system at the lower end of the acceptable voltage ranges and reduces reactive power in the distribution system resulting in lower system losses, lower energy consumption, and an overall system energy and demand reduction.
    - Distribution Automation: provides better monitoring and control of the distribution system by providing real time data as well as the capabilities to remotely locate faults and remotely operate equipment to restore service in the event of fault or loss of upstream power
    - Advanced Metering Infrastructure: allows a utility to leverage its AMI data for better data analytics and reporting.

- **Voltage Conversion** – Completion of PUC's long standing voltage conversion project during this filling period is expected to bring benefits in a number of ways. Firstly, these remaining circuits once transferred over from 4kV to 12kV, will allow for the connection of DER as the newer 12kV feeders include the necessary protection systems to support their connection. Secondly, the elimination of multi-circuit lines along many streets should lead to a less complex and better hardened system better able to withstand more severe wind and ice loading weather conditions expected with climate change. Furthermore, the reduction in electrical losses retiring two 4kV stations and with the move to higher voltage are expected to bring advantages from an environmental perspective.

- **GIS Utility Network (UN) Migration** – PUC's existing GIS is based on Geometric Network technology, which is approximately twenty-five years old, approaching end of useful life, and will no longer be supported by the vendor in the next three years as they move exclusively to a UN platform, which is industry typical practice platform. As a result, PUC is planning to undertake a GIS UN Migration project in 2024/25, wherein all of PUC's existing asset information and custom developed applications will be migrated to the new platform.

In addition, advanced technology will be considered and incorporated in system design selectively over the forecast period. Where benefits outweigh the costs, advanced technologies may be incorporated during implementation of asset renewal projects, to meet the current and future needs of the customers, to improve operating efficiency and to support the integration of renewables and smart grid technologies.

Consideration of Traditional Planning Needs

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

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

Load growth is a direct input into PUC's planning for system access and system service type projects. At a macro-level, there are currently no overall system level capacity constraints in the supply system that would prevent connection of anticipated overall load or generation customers during the next five years. However, an analysis of loading data archived in PUC SCADA historian has revealed that a localized shift in demand is occurring in a westerly portion of the service territory and investments in additional infrastructure in that area is proposed to mitigate the capacity constraints previously discussed in Section 5.3.2.2.1.

Asset condition and reliability data are key inputs considered by PUC when identifying, selecting and prioritizing system renewal expenditures. A significantly large portion of the existing infrastructure employed on PUC's supply network has, or soon will reach a service age beyond its typical useful life. Through a recently completed ACA exercise, a significantly large fraction of critical power supply infrastructure components employed at distribution stations, overhead lines and underground distribution system have been determined to be in "fair", "poor" or "very poor" operating condition. In the absence of investments into asset renewal, the existing infrastructure presents high risk of failure in service, affecting supply system reliability and public safety. However, renewal and replacement of all infrastructure components determined to be in "poor" or "very poor" condition during the next five years, would be difficult to manage through PUC's resources and it would lead to unaffordable increase in retail rates. Given that the highest priority concern from almost all customer engagement activities is the high cost of electricity bills and an increasing worry over affordability followed by the importance placed on reliability and customer communications, PUC's challenge is to seek an optimized balance of these generally opposing factors. Therefore, in preparing this DSP, PUC has focused on prioritizing the investments into renewal of the most critical infrastructure components, to achieve the balance required between keeping the power supply reliability from degrading while maintaining the electricity distribution rates at affordable levels.

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.

Capital expenditure trends over the 2018 to 2027 period, for net capital expenditures and the underlying investment categories, are shown in Figure 5.4-14.

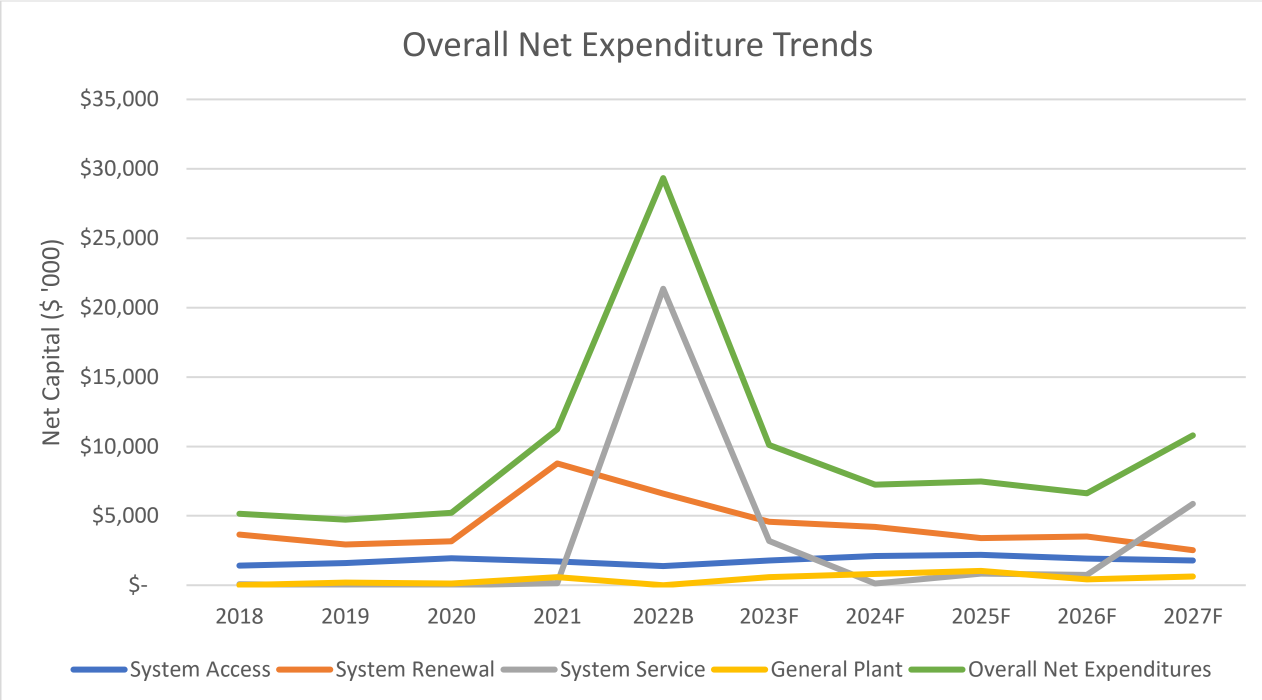


Figure 5.4-14: Overall Net Capital Expenditure Trends

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

Over the historical period, a relatively stable trend is observed from 2018 to 2020, which is followed by a jump in costs in 2021 and 2022. As previously explained, the observed increases in 2021 and 2022 are driven by the Substation 16 ICM costs, the SSG Project ICM costs, and the additional renewal costs implemented to support the SSG Project.

Costs are reduced significantly in 2023 relative to 2022 but are still higher than other forecast years as a result of the reallocation of a portion of the SSG Project costs from 2022 to 2023 for testing and optimization purposes. Following the completion of the SSG Project, a reduced and relatively stable trend in overall net capital expenditures is observed from 2024 to 2026. This is followed by a significant increase in 2027 which is driven by PUC's proposed new station build in the west end of its service territory. This new station is required to accommodate the localized demand in this area which is being driven by requests for connection of several large and medium sized commercial customers. Additional information on this investment can be found in Section 5.2.1.4. To accommodate the increased level of investment associated with this new station build, PUC has decreased the level of investment elsewhere in its budget (i.e., system renewal) to help balance the overall budget and limit the overall impact on rates.

As previously noted in Section 5.4.1.3.5, when excluding the SSG Project costs, the average overall capital expenditures forecast is approximately 14% greater than the historical plus bridge year average, corresponding to an annualized increase of 2.65%. Given the current rate of inflation[7], investments over the next five years will allow PUC to continue to meet customer and system needs while also keeping the rate impact to customers at or below future inflation.

5.4.2.1 Material Investments

The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g., unique characteristics; marked divergence from previous trend) are supported by evidence that enables the OEB's assessment according to the evaluation criteria set out below. The level of detail filed by a distributor to support a given investment project/program should be proportional to the materiality of the investment.

For this Application, the materiality threshold is $135,000. All capital projects, proposed to be implemented during the Test Year, with investments level exceeding the materiality threshold, are listed in Table 5.4-15. The project prioritization criteria along with scoring to determine project priority rankings are shown in Table 5.4-16.

The first five projects in the table fall in the system access category for which meeting the regulatory obligations is the primary driver. Of the next 13 projects in the table, one corresponds to the SSG Project, ten belong to the system renewal category, for which supply system reliability and public safety are the primary drivers, and the final two projects belong in the general plant category, for which business operations efficiency and non-system physical plant are the primary drivers. Detailed scope of each project along with its key driver and justification are described in detail in Appendix A and briefly summarized below.

In addition to these material Test Year projects, PUC is also proposing to undertake a GIS upgrade/ UN migration project in 2024/25. A formal business case is not yet available for this project as it is not being undertaken in the Test Year, however additional project information is included in Section 5.4.2.1.1 below.

[7] Consumer Price Index by product group, monthly, percentage change, not seasonally adjusted, Canada, provinces, Whitehorse, Yellowknife and Iqaluit. Reference Period: May 2022. https://www150.statcan.gc.ca/t1/tbl1/en/tv.action?pid=1810000413&pickMembers%5B0%5D=1.2&cubeTimeFrame.startMonth=05&cubeTimeFrame.startYear=2022&referencePeriods=20220501%2C20220501

Table 5.4-15: Proposed Capital Investments during Test Year - Projects over Materiality

Category	Project Code	Project Description	Priority Rank	2023 Planned Expenditure ($ '000)
System Access	1C100-1	Customer Demand - Services	1	924
System Access	1C100-2	Customer Demand - New Subdivisions	1	301
System Access	1C100-3	Customer Demand - Joint Use	1	171
System Access	1C100-4	Customer Demand - City Projects	1	201
System Access	1C100-7	Revenue Meters	1	187
System Renewal	1C200-1-1	Unplanned OH Renewal (forced)	1	276
System Renewal	1C200-1-2	Unplanned UG Renewal (forced)	1	376
System Renewal	1C300-1-5	OH Renewal - Transformers (PCBs)	1	711
System Service	1C400-1-1	System Wide - Sault Smart Grid (SSG) Project	2	3,190
System Renewal	1C300-1-3	OH Renewal - Voltage Conversion	3	864
System Renewal	1C300-1-4	OH Renewal - Restricted Conductor	4	362
System Renewal	1C300-1-2	OH Renewal - Poles	5	602
System Renewal	1C3033-3-3	Stations Renewal - Switchgear, Protection & Control Renewals	6	176
System Renewal	1C300-2-8	UG Renewal - Vaults	7	401
System Renewal	1C300-3-1	Stations Renewal - Building & Fence Repairs	8	144
General Plant	1C500-2-1	Buildings	9	238
General Plant	1C500-2-1	Tools & Equipment	10	295
System Renewal	1C300-1-1	OH Renewal - General Asset	11	172
Total Net Expenditure on Material Projects During Test Year				**9,591**
Total Net Expenditure on Capital During Test Year (All Investment Categories)				**10,113**

Table 5.4-16: Prioritizing Matrix for Test Year Projects over the Materiality Threshold

Rank	Area	Project / Program	Public Safety Impact				Outage Customer Impact				Customer Value for $				System Service Improvements				Project Interdependence				Score (%)
			Weight: 40%				Weight: 10%				Weight: 15%				Weight: 10%				Weight: 25%				
			R	C	PSI	PSI (n)	QTY	HRS	COI	COI (n)	$k	C	CV	CV (n)	QTY	SIV	SSI	SSI (n)	SQI	FI	PI	PI (n)	
1	System Access	Services, New Subdivision, Joint Use, City Projects, Revenue Meters	Ranked as first priority as these are non-discretionary (Customer/External Driven)																				n/a
1	System Renewal	Unplanned OH & UG Renewal																					n/a
1	System Renewal	OH Renewal - Transformers (PCBs)	Ranked as first priority as these are non-discretionary (Regulatory Compliance)																				n/a
2	System Service	System Wide – Sault Smart Grid (SSG) Project	0	0	0	0.0%	33000	1.81	59747	7.7%	24548	33000	1.3	0.3%	33000	5	165000	8.7%	2.5	2.5	6.3	1.1%	17.8
3	System Renewal	OH Renewal - Voltage Conversion	1	1	1	0.3%	82	1.5	123	0.0%	864	82	0.1	0.0%	82	1	82	0.0%	10	10	100.0	17.4%	17.7
4	System Renewal	OH Renewal - Restricted Conductor	7.5	5	38	9.5%	111	3	333	0.0%	362	111	0.3	0.1%	111	1	111	0.0%	5	5	25.0	4.4%	14.0
5	System Renewal	OH Renewal - Poles	5	10	50	12.7%	480	1.5	720	0.1%	602	480	0.8	0.2%	480	1	480	0.0%	1	5	5.0	0.9%	13.9
6	System Renewal	Stations Renewal - Switchgear, Protection & Control Renewals	2.5	10	25	6.4%	2357	2.5	5893	0.8%	176	2357	13.4	3.2%	2357	5	11786	0.6%	0	0	0.0	0.0%	11.0
7	System Renewal	UG Renewal - Vaults	5	5	25	6.4%	1000	4	4000	0.5%	401	1000	2.5	0.6%	1000	5	5000	0.3%	2.5	2.5	6.3	1.1%	8.8
8	System Renewal	Stations Renewal - Building & Fence Repairs	2.5	5	13	3.2%	2357	1.5	3536	0.5%	144	2357	16.3	3.9%	2357	0	0	0.0%	0	0	0.0	0.0%	7.5
9	General Plant	Buildings	0	0	0	0.0%	0	0	0	0.0%	1750	33000	18.9	4.5%	33000	0	0	0.0%	0	0	0.0	0.0%	4.5
10	General Plant	Tools & Equipment	0	0	0	0.0%	2357	1	2357	0.3%	295	2357	8.0	1.9%	2357	2.5	5893	0.3%	0	0	0.0	0.0%	2.5
11	System Renewal	OH Renewal - General Asset	2.5	2.5	6	1.6%	100	4	400	0.1%	172	100	0.6	0.1%	100	1	100	0.0%	1	1	1.0	0.2%	2.0

Notes Regarding Ranking Methodology:

1) Public Safety Impact (PSI) due to failure = Risk (R) x Consequence (C) where (R = (1 = low, 10 = high), C = (1 = low, 10 = high)
2) Customer Outage Impact (COI) = (Qty Customers Affected (QTY) x anticipated outage hours/year (HRS))
3) Customer Value (CV) = Customers Served (C) / $100,000 ($K)
4) System Service Improvements (SSI) = Quantity of Customers Affected (QTY) x Service Improvement/Enhancement Value (SIV) factor, (1 = low, 5 medium, 10 = high)
5) Project Interdependence (PI) = Impact of a project not proceeding negatively impacting the ability to complete other future planned work = (SQI = service quality impact x FI = financial impact), values (1 = low, 10 = high)
6) Score = Sum of five factors above (Public Safety, Outage Customer Impact, Customer Value, System Service Improvements and Project Interdependence after weighting each according to weighting shown in the spreadsheet above allowing for a maximum attainable score
7) (n) represents a normalized score where for the ranked projects, each is normalized to a scale of 0%-20%
8) Rank is determined by placing Scores for all planned capital projects in a rank ordered list. A rank of 1 represents the highest priority. Non-discretionary customer demand work and capital work driven by unplanned repairs and regulatory compliance have all been weighted equally and assigned a Rank of 1
9) It is noted that the projects within this matrix are those previously screened through the Asset Management Plan process, and they therefore represent only the most critical projects identified and prioritized through that process.

System Access: Services, New Subdivision, Joint Use, City Projects, Revenue Meters (Ranked #1)

These projects are required to fulfil PUC's regulatory obligations under its Condition of License and Conditions of Service, and are primarily driven by customer demand. The first project involves fulfilling customer requests for new services or upgrade of existing services. The second project covers requests from land developers involving servicing of multiple lots within subdivisions. The third project covers requests from telecommunication companies in the City for make ready work to facilitate joint use of distribution infrastructure by third parties. The fourth project involves meeting requests from the municipality to relocate overhead or underground lines installed in the public right-of-way to coordinate with road widening projects. The fifth project is related to the supply, installation and maintenance of revenue meters installed at each customer service point for retail settlement and billing purposes for all customers connected to PUC's distribution system.

Forced System Renewal: Unplanned OH & UG Renewal (Ranked #1)

These two projects involve reactive expenditure to restore power following a power interruption caused by equipment failures by replacing the failed and unsafe distribution system assets with new equipment. These expenditures are required in accordance with PUC's Condition of License and the DSC. The key drivers for these projects are supply system reliability and public safety, because when equipment has failed in service, the proposed expenditure becomes necessary to restore power and remove the unsafe equipment from service. Unplanned OH renewal is intended to cover expenditure for renewal of failed assets on overhead lines and Unplanned UG Renewal is intended to cover expenditure for renewal of assets on underground distribution system.

System Renewal: OH Renewal - Transformers (PCBs) (Ranked #1)

This project involves the replacement of PUC's remaining PCB-contaminated pole mounted transformers in accordance with PCB regulations, which set a deadline of December 31, 2025 to eliminate electrical transformers with concentrations of PCB's greater than 50 ppm. This is a high priority investment in accordance with the Federal PCB regulations.

System Service: System Wide – Sault Smart Grid Project (SSG) (Ranked #2)

As previously noted, the SSG Project will transform PUC's distribution system by integrating technologies that allows for voltage optimization, monitoring of the distribution system, and leveraging real time data. This will improve PUC's system reliability and operational effectiveness, while positioning PUC for future growth and grid modernization.

Since $3.19M of the SSG Project net spend has been reallocated to the 2023 Test Year, PUC has included the SSG Project in its prioritization process to demonstrate the priority of the project relative to other material investments proposed in the Test Year. The SSG Project is ranked #2 out of 11, following the non-discretionary projects detailed above. Further justification for the prioritization of the SSG Project is included in Section 5.3.6.2.1.

Since the SSG Project has been pre-approved as part of the EB-2020-0249/EB-2018-0219 ICM application, PUC has not prepared a material investment narrative for this project.

System Renewal: OH Renewal - Voltage Conversion (Ranked #3)

This program involves renewal of overhead distribution system assets by rebuilding of the existing overhead distribution system currently operating at 4.16 kV. The overhead lines will be rebuilt to operate at 12.47 kV upon completion of the projects. As detailed in PUC's asset condition assessment report, PUC has approximately 22 km of 4.16 kV line and two 4.16 kV distribution stations in service (Substations 4 and 5), most of which is in poor condition and at the end of their service life.

Project interdependence is the primary criterion that impacted the scoring of this project, as the work proposed will bring an end to PUC's voltage conversion program which is essential to allowing the retirement of the final two remaining end of life 4.16 kV stations (i.e., Substation 4 and 5) and retirement of all remaining 4.16 kV stock from storage, tools and training. Completion of the long-standing voltage conversion program will simplify, standardize and improve the overall performance and efficiency of the distribution system. There are 82 customers immediately impacted by the remaining works under this program.

System Renewal: OH Renewal - Restricted Conductor (Ranked #4)

PUC has identified #6 copper overhead primary conductor as a safety hazard. It is classified by PUC as "restricted wire". Due to the nature of the conductor, it being small and constructed of copper, its tensile strength is known to degrade over years of use. Due to this, the conductor is prone to failure. Additionally, when the conductor fails, due to its nature, the fault current dissipates quickly and therefore may not trigger the nearest protective equipment. This may cause the conductor to remain energized in an area where staff or the public may come into contact. The conductor is replaced with #2ACSR, along with related insulation and aged and poor condition infrastructure. The specific project areas covered by this project are identified in the supporting material narrative.

Public safety impact is the predominant criterion that impacted the scoring of this project since the risk of failure is relatively high. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service but working around restricted conductor can be handled through work procedures until all restricted conductors can be removed. PUC has already eliminated the risk from high public traffic areas, parks, and schools to limit the consequence of a failure, but the work proposed over the DSP period is required to continue eliminating the risks associated with the #6 conductor. There are 111 customers immediately impacted by the projects planned for the 2023 Test Year.

System Renewal: OH Renewal – Poles (Ranked #5)

This project involves replacement of poles determined to be "unsafe" due to degradation of their structural strength, based on in-situ testing of the poles. For the forecast period, PUC plans to replace approximately 60 wood poles per year.

Public safety impact is the predominant criterion that impacted the scoring of this project due to the potential failure mode of this asset class, with an assumed average impact of eight customers per pole (or 480 customers impacted annually). Deferring or reducing the quantities of poles proposed for replacement will result in an increased safety and reliability risk.

System Renewal: Stations Renewal - Switchgear, Protection & Control Renewals (Ranked #6)

This project involves the renewal of stations assets. As identified through the ACA, a number of breakers associated with the switchgear have reached end of life and are at greater risk of failure.

Public safety impact is the primary criterion that impacted the scoring of this project, followed by customer value for dollars spent. In case of an outage or loss of a main breaker at one of PUC's 14 distribution stations, over 2,350 customers would be affected on average. In terns of non-operational breakers, a fault could lead to high liability consequences such as shock, burn, or fire. PUC is proposing to replace two station breakers per year over the forecast period. Deferring or reducing these planned renewals will result in an increased safety and failure risk.

System Renewal: UG Renewal – Vaults (Ranked #7)

This project involves the rejuvenation of underground vaults and manholes that have been identified as deficient and are therefore more prone to failure. PUC is proposing to proactively rejuvenate one major vault and two minor vaults per year over the forecast period, as well as a manhole rejuvenation in the test year.

Public safety impact is the primary criterion that impacted the scoring of this project. A failure of a vault or manhole could pose significant safety hazards to workers and the public, while also impacting the reliability and effective operation of the system. A single failure could impact 250 customers.

System Renewal: Stations Renewal - Building & Fence Repairs (Ranked #8)

PUC has identified the need for a station building and fences repair program to ensure the upkeep of the buildings and fences that are required for the safe and efficient operation of stations in the system. Failure risk and safety are primary drivers for this project.

Customer value for dollars spent and public safety impact are the primary criteria impacting the scoring of this program. Since PUC has 14 stations, it is assumed that over 2,350 customers would be impacted on average per station. Other than the handful of grounding repairs and breached station fence repairs anticipated, the balance of other repairs does not constitute an immediate material safety risk. However, if left unaddressed for too long, they are expected to lead to a decrease in service levels through reliability reductions and lead to the need for much more costly remedial solutions in the long term. (e.g., the need to replace an entire switchgear cubicle or overhead structure due to advanced rust rather than sanding and painting minor rusting areas proactively).

General Plant: Buildings (Ranked #9)

This project involves the renewal of buildings. PUC is planning to invest in the upkeep of PUC's main facility, which represents the critical backbone of PUC's 24/7 operations. Ongoing investments in this facility are required to ensure safe and reliable continuation of PUC's operations.

The proposed building investments have been ranked as 9^{th} out of the 11 initiatives for the Test Year. Impacts in the area of safety, customer outages, system service and project interdependence are minimal relative to other projects. As a result, the benefits to be derived from this project are primarily in the area of customer value for dollars spent, where customer dollars are focussed on eliminating inefficiencies that over time would lead to burdensome O&M expenses or costly unplanned capital expenditures to address if deferred for too long. All PUC customers will derive value from this project.

General Plant: Tools & Equipment (Ranked #10)

This project involves the renewal of tools/equipment. The planned investments in tools/equipment will help improve PUC's testing and inspection regimes which in turn will enable PUC to make better informed asset investment decisions in order to continue providing safe, reliable and effective services to customers.

Customer value for dollars spent is the primary criterion that impacted the scoring of this project. The equipment proposed to be purchased is critical in PUC being able to carry out their testing programs and gather further data to enable PUC to continue to determine the condition of assets and develop an informed ACA process. This data is then used as an input to help inform the investment plan.

System Renewal: OH Renewal - General Asset (Ranked #11)

This project involves small unplanned projects over the forecast period that are not considered emergency repairs. This includes the removal, cleanup and disposal of pole butts and the replacement of minor assets in poor condition which are identified through maintenance programs, field inspections and/or information provided from third parties.

Public safety impact is the primary criterion that impacted the scoring of this project, however this is a lower priority investment relative to other material projects detailed above. Although the safety risks of the pole after the wires and related infrastructure have been minimized, completion of the project immediately impacts PUC's image in the community, and it is important to complete the projects and restore the network to pre-existing conditions. Given that this investment involves a variety of projects, PUC has assumed that approximately 100 customers would be impacted annually if this work was to be deferred.

5.4.2.1.1 GIS UN Migration Project

The GIS system is used as PUC's primary asset registry, keeping track of the location and important attributes for all assets in the field. The data stored in the GIS is utilised by all aspects of the company and is a critical part of the operational infrastructure. Importantly, the data stored in the GIS is used by the operations group to perform activities ranging from responding to outages to field maintenance. This can include switching and load transfers during outages. It is imperative that the data is 100% accurate to ensure field staff are directed to the correct equipment when undertaking these activities. The GIS is used on a daily basis.

An assessment took place in 2020 regarding the current use of PUC's GIS. It was determined that using the "current" approach left PUC behind in today's evolving GIS technology and behind what is considered industry typical practice. Many LDCs are already utilizing tablets and smart phones in the field to view and update information. In January 2021, ESRI Canada was consulted to provide a gap analysis and assist in developing a technology roadmap for the migration to the Utility Network (UN). The output of the services engagement provided a current state assessment, future state and implementation roadmap that will identify and address high-priority operational and technical governance-related requirements.

PUC's existing GIS is based on Geometric Network technology, which is approximately twenty-five years old, approaching end of useful life, and will no longer be supported by the vendor in the next three years as they move exclusively to a UN platform. The UN technology is replacing the geometric network which has a more open web-based architecture. It is the latest model, that is becoming typical industry practice, and allows for enhanced performance with applications such as ArcGIS Portal and ArcGIS Online, enhanced field mobility and direct editing. ArcGIS Desktop is the application that will be replaced with ArcGIS Pro which is already in production.

As a result, PUC is planning to undertake a GIS UN Migration project in 2024/25, wherein all of PUC's existing asset information and custom developed applications will be migrated to the new platform. Migration to the new platform, including all of PUC's existing asset information and custom developed applications is expected to take two years. The current cost estimate for the project is between $900,000 - $1,200,000. The diagram below shows the current propose phases (one to three) defined as Design, Execution and Transition.

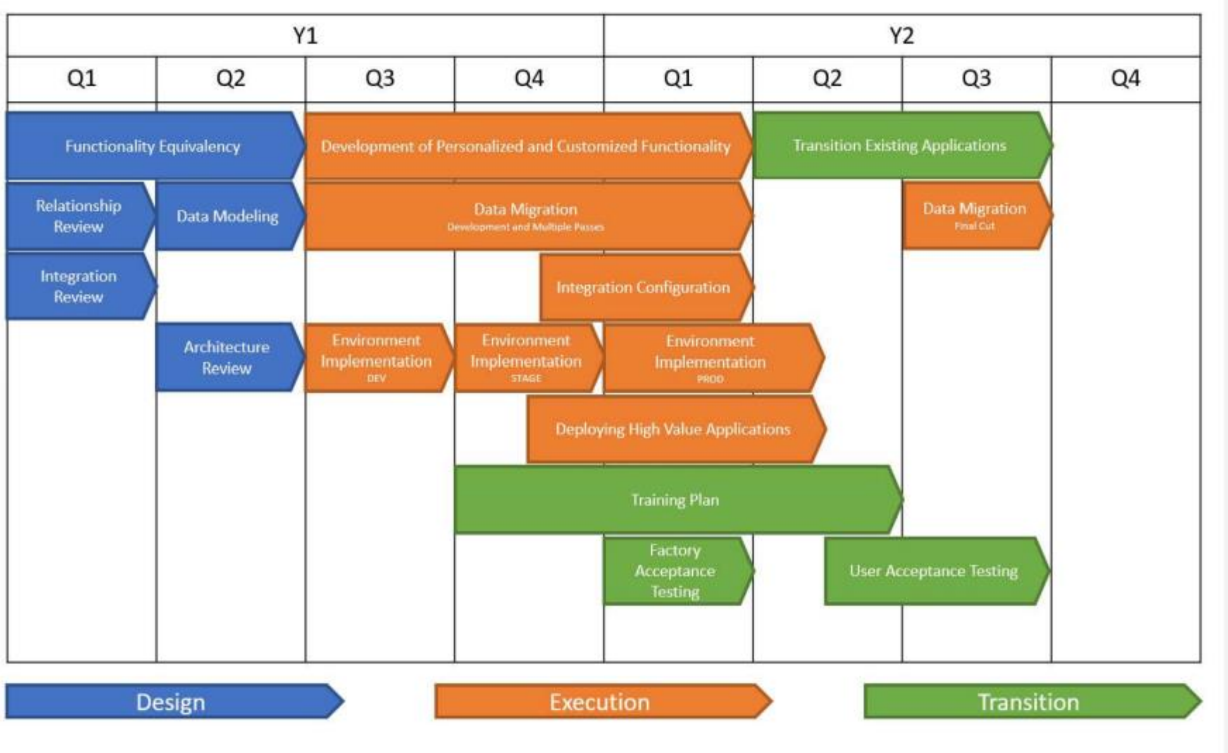


Figure 5.4-15: GIS UN Migration Project Phases

The primary driver for this project is technology obsolescence, with it becoming unsupported by the vendor in the next three years. If PUC does not upgrade the GIS, a vital backbone to PUC's operations, such that it is supported, it could significantly impact PUC's ability to manage the grid safely, effectively and efficiently.

In addition, by moving to the UN platform this will allow PUC to modernize and implement industry best practices such as field staff being able to access GIS on their tablets and phones to access the latest information as well as update it straight away. This not only ensure field staff have the most up to date information to respond and perform their tasks, but it also enables efficiency in the inputting of data from the field, responding to work request and outages. Rather than documenting this information on paper and then inputting this back at the office, this only needs to be recorded once and straight onto the live system.

PUC is currently reviewing and working with the vendors to put a detailed plan together to deliver this project in 2024 and 2025. This will include a more detailed scope and updated costs.

Appendix A

Material Investment Narratives

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

CUSTOMER DEMAND – SERVICES

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

In an effort to comply with the Distribution System Code (DSC) requirements and to support ongoing customer demand and customer-initiated requests, service projects have been budgeted based on historical expenditure trends and predictions from the City of Sault Ste. Marie regarding project developments. Service projects vary from year to year and may include installations of new/upgraded residential services, commercial services, new transformers to support services, replacement/relocation of infrastructure due to customer requests, and other miscellaneous requests from customers. New connections and service upgrades are planned using standardized designs that meet the requirements of O. Reg. 22/04, made under the Electricity Act, 1998. All requests are also reviewed against the DSC requirements and reasonableness to determine PUC's contribution level.

As part of this program, PUC typically installs between 50 and 100 new residential services annually contingent upon the local economy. Many of the new services installed are located in residential subdivision areas, requiring minimal distribution system upgrades. Some new/upgraded services in existing areas require distribution system upgrades to service the customer. These upgrades include, but are not limited to pole replacements, transformer installations/replacements and system expansions.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Year-over-year fluctuations in the volume of work performed under this program vary based on the number of customer requests received each year. The timing of work depends on when the customer request is made.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)				Forecast Costs ($ '000)					
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	628	1,191	1,080	1,331	1,164	1,254	1,273	1,294	1,364	1,274
Contributions	(89)	(163)	(169)	(238)	(322)	(330)	(343)	(350)	(357)	(364)
Capital (Net)	539	1,028	911	1,093	842	924	929	944	1,007	910

4. Economic Evaluation (Expansion Projects)

This is generally not applicable. From time to time a new residential service will require an extension of our electrical distribution system. In such scenarios, PUC follows the regulated process within the DSC to fairly expand the electrical distribution system.

5. Comparative Historical Expenditure

The historical costs for services are identified in Section 3 of this document. Typically, the number and scope of services will fluctuate each year depending on the requests made by customers. Expenditures under this program are forecast based on historical trends and considerations of forecast growth and development.

6. Investment Priority

This investment program is classed as a high priority since it is a non-discretionary program driven by customer service requests and regulatory compliance. When customer connection and service upgrade requests are initiated, they will take priority over other system undertakings and plans.

7. Alternatives Analysis

Since this is a non-discretionary program, doing nothing is not a viable option. Alternatives are considered on a case-by-case basis, and the most practical solution is installed considering safety, regulatory, system reliability, economics and customer relations.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	PUC considers options when services are installed/revised on a case by case basis to provide the most cost-effective solution for all parties. Where appropriate, PUC might also revise timing of planned projects within similar areas to gain overall economic efficiencies.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	The main benefit to customers is timely connection to the electrical system and having access to safe and reliable electricity. By assuring sustainable, reliable, cost-effective electrical services to customers in PUC's service territory, this program contributes towards economic development in the region as well.
Reliability	There will be negligible impact to reliability performance resulting from this project. Very minor upgrades to individual services should result in less long-term outages for the individual customer.
Safety	All new/upgraded services are installed to the most current safety standards available ensuring safety for all.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Mandated Service Obligations* - This program is driven by customer requests and regulatory compliance. It is essential for PUC to maintain customer satisfaction and compliance with the DSC by providing all customers with access to safe and reliable electricity.

ii. Secondary Drivers: *New Customers, Increased Revenue & Customer Relations* - This investment will increase the quantity of customers supplied by PUC and revise service sizes affecting revenue stream. Replacing/relocating assets to accommodate customers provides PUC with an opportunity to improve customer relations and replace assets at a reduced cost through customer contributions.

iii. Information Used to Justify the Investment: The new connections and service projects are based on customer requests and vary year to year based on need. The number of customer connections and service upgrades are forecast based on historical trends and projections from the City of Sault Ste. Marie regarding project developments and population growth. At a minimum, PUC meets with the City annually to coordinate and to review anticipated development and associated growth. Additional information on PUC's engagement efforts are included in Section 5.2.2 of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives *considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).*

i. *Demonstrating Accepted Utility Practice*: PUC informs customers that it is their responsibility to coordinate third party services to be installed. PUC provides contractor information to customer for the customer to obtain benefits of installing multiple utilities in the same excavation. PUC designs and installs services as per USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access. All new/upgraded services are installed to the most current safety standards.

ii. *Cost-Benefit Analysis:* PUC considers options when services are installed/revised on a case by case basis to provide the most practical and cost-effective solution for all parties. PUC also considers other projects when installing new services. If the service is within the area of an upcoming project, PUC might revise timing of projects to gain overall economic efficiencies.

iii. *Historical Investments & Outcomes Observed:* PUC routinely provides new connections and service upgrades to its customers. These investments have enabled unrestricted access to the distribution system which in turn has allowed continued growth and development within SSM. They also allowed PUC to ensure dependable and reliable service for its customers.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

CDM is not applicable for new customer connections and service upgrades.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this investment.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

CUSTOMER DEMAND – NEW SUBDIVISIONS

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

To comply with Distribution System Code (DSC) requirements and support ongoing customer demand, subdivision projects have been budgeted for the forecast years based on historical expenditures and predictions from the City of Sault Ste. Marie on development. The projects include installations of new subdivisions inclusive of the expansion of PUC's distribution system and transformation up to property lines for projected residential customers. To service many of the expansions, some existing asset upgrades are required, including, but not limited to pole replacements, overhead switch replacements/coordination, pad mounted switch replacements. All requests are reviewed against the DSC and reasonableness to determine PUC's contribution level.

PUC is currently anticipating approximately five major subdivision developments in the 2023 Test Year for the connection of approximately 150 new lots throughout PUC's service territory. These subdivisions are listed below, however the subdivisions listed may or may not proceed and additional subdivisions may be presented.

- Allen's Side Road
- Eastside Subdivision
- Fox Run Subdivision
- Jack Roderick Way
- Queensgate Greens

Where possible, capital contributions towards the cost of these projects are collected by PUC in accordance with the DSC and the provisions of its COS.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Key factors that may affect timing include funding and preliminary payments from customers/developers; procurement and sourcing of materials and labour to complete installation. In addition, the schedule for these types of projects is largely dictated by third-party developers and is therefore outside of PUC's control.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018*	2019*	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	(1)	65	81	416	299	376	382	388	409	382
Contributions	0	6	(18)	(80)	(63)	(75)	(78)	(80)	(81)	(83)
Capital (Net)	(1)	70	63	336	236	301	304	308	328	299

*****Negative capital and positive contribution amounts are due to timing issues around receiving contributions from developers.*

4. Economic Evaluation (Expansion Projects)

Subdivisions typically involve an expansion of the electrical distribution system. As outlined in the DSC, capital contributions received from subdivision developers are calculated considering the initial cost of the expansion, operation and maintenance costs and anticipated revenue to be received by PUC. An example of an economic evaluation is shown in Figure 1 below for reference.

Net Present Value Summary

	With taxes	Without Federal and Provincial taxes
1. PV of Operating Cash Flow		
a) PV of Net Operating Cash Flow	130,034	130,034
b) PV of Taxes	-34,459	0
PV of Operating Cash Flow	95,575	130,034
2. PV of Capital	-175,000	-175,000
3. PV of CCA Tax Shield	17,852	
NET PRESENT VALUE	($61,573)	($44,966)

Figure 1: NPV Summary Example

Economic evaluations for the five major subdivision developments expected in the 2023 Test Year are not available at the time of writing since the project details including scope, budget and schedule are still under development. Economic evaluations will be completed closer to project execution once the project details are finalized.

5. Comparative Historical Expenditure

Connecting new subdivisions is an ongoing annual activity for PUC. Historical costs for subdivisions are identified in Section 3 of this document. Typically, the scope of subdivision developments will fluctuate each year depending on third-party requests. PUC considered historical spend, projected growth, inflation and other supply chain and material cost factors when generating the forecast costs for this program.

6. Investment Priority

This investment program is classed as a high priority since it is a non-discretionary program driven by customers and third party requests, which is essential to maintain regulatory compliance and customer satisfaction. When subdivision requests are initiated under this program, they are balanced with other mandatory system access projects but will take priority over other system undertakings and plans.

7. Alternatives Analysis

Since these are non-discretionary projects, doing nothing is not a viable option. PUC reviews options for subdivision projects on a case by case basis to ensure the solution is designed and constructed in a safe, low maintenance and economical manner for all parties. An initial design is presented to the developer with the option to discuss alternatives based on the developer needs for their subdivision projects. The final decision is made considering safety, regulatory, system reliability, economics and customer relations.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC associated with the subdivision work.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

Currently there are no Leave to Construct (LTC) approvals required as part of this program. However, if tasks arise that require LTC approval, PUC will follow the required protocol.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Although this program will typically have no impact on existing system operation efficiency, PUC strives to pursue efficiency and cost-effectiveness with regards to the execution of any subdivision developments within its service territory.
Customer Value	Customers benefit by being supplied with reliable service built to current standards. By assuring sustainable, reliable, and cost-effective electrical services to customers, this program also contributes towards economic development in the region.
Reliability	When designing new system expansions to accommodate subdivisions, PUC evaluates its whole system to identify opportunities to improve safety, reliability, and system redundancy. For example, some expansions caused by subdivision developments provide PUC with an opportunity to further loop its system to reduce outage areas more effectively as they occur. Expansions also allow PUC to review circuit and system imbalances, and further balance the electrical

Primary Criteria for Evaluating Investments	Investment Alignment
	system through connection of additional demand. Through this, customers will have more reliable access to electricity.
Safety	All new subdivision work considers safety as paramount by designing and installing to USF standards and PUC standards, in coordination with municipal road allowance standards and/or specifics approved by a Professional Engineer.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Mandated service obligations* – These projects are mandatory, and the scope and timelines are based on requirements put forth by developers and/or obligations set forth in connecting customers in the DSC. PUC considers and complies with all requirements while ensuring all installations add to a safe, efficient, and reliable system.

ii. Secondary Drivers: *New Customers, Increased Revenue & Customer Relations* – This program will increase the quantity of customers supplied by PUC affecting revenue stream. Expanding the distribution system to connect new subdivisions and in turn, individual customers, provide PUC with an opportunity to improve customer relations.

iii. Information Used to Justify the Investment: PUC's subdivision investments are driven by regulatory compliance and customer demand. Subdivision investments are forecast based on historical trends and projections from the City of Sault Ste. Marie regarding project developments and population growth. Additionally, PUC consults with primary subdivision developers on an ongoing basis to inquire about upcoming plans to ensure PUC is prepared.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: PUC informs developers that it is their responsibility to coordinate third party services to be installed. PUC provides contractor information to developer for the developer to obtain benefits of installing multiple utilities in the same excavation. PUC designs and installs as per the latest CSA, USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access.

ii. *Cost-Benefit Analysis:* Subdivision alternatives are considered on a case by case basis to provide the most practical and cost-effective solution for all parties.

iii. *Historical Investments & Outcomes Observed:* PUC routinely accommodates new subdivision projects within its service territory. These investments have enabled unrestricted access to the distribution system, which in turn has allowed continued growth and development within Sault Ste. Marie.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

CUSTOMER DEMAND – JOINT USE

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC is a partner with multiple third-party communication companies in Sault Ste. Marie. Third-party communication companies request to attach to PUC poles to minimize infrastructure. In doing so, PUC charges a monthly rental fee established in agreements between each company. On a regular basis, third-party companies will apply for revisions to their existing attachments or for new attachments to be added to coordinate with their business objectives and customer demand. When applications are received, it is identified whether the existing PUC infrastructure is adequate to support the new/revised infrastructure in a safe manner. If PUC's infrastructure requires revisions (make ready work), the work is performed by PUC on a time and material basis.

Currently, PUC limits the number of attachments on a PUC pole to three. Ensuring a single attachment company resides on a maximum of one attachment position allows other third-party companies the same potential benefit.

Investments within this program are geared towards "make-ready" work on PUC infrastructure which may include replacement/installation of poles, anchors and related infrastructure.to accommodate the use of this equipment by joint use partners. Joint use projects are expected to increase between 2023-2025 to accommodate the government initiatives to increase broadband coverage in rural areas but are expected to return to standard values afterwards.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Tasks under this project occur throughout the year as requested by third party companies and is therefore outside of PUC's control. Resource constraints might also affect the timing of the work. New regulations further accelerating response requirements may further impact resource concerns as well.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021*	2022	2023	2024	2025	2026	2027
Capital (Gross)	280	755	569	19	110	251	254	259	136	127
Contributions	(190)	(566)	(199)	(64)	(37)	(80)	(83)	(85)	(43)	(44)
Capital (Net)	90	189	370	(45)	73	171	171	174	93	83

**The net negative capital amount shown in 2021 is due to a timing issue associated with receiving capital contributions from the Bell Canada Fibre-to-the-Home (FTTH) program.*

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Undertaking work to accommodate the use of PUC's distribution equipment for third party joint use is an ongoing activity for PUC, and the historical actual costs associated with this program are shown in Section 3 of this document. Investments under this program can vary substantially year over year depending on the timing and scope of third party developments being undertaken within PUC's service territory. As a result, when referencing historical average expenditures to generate forecast costs under this program, large unique projects are excluded from this. For example, increased costs in 2018-2020 over the historical average are contributable to a Bell Canada Fibre-to-the-Home (FTTH) program where Bell attached new infrastructure to approximately 4,000 PUC poles. This project required significant make ready work to ensure PUC's infrastructure was safe to attach to. Forecast costs are also informed by ongoing conversations with third party communication companies.

6. Investment Priority

This investment program is classed as a high priority since it is a non-discretionary program driven by third party requests and contractual obligations. When joint use requests are initiated under this program, they are balanced with other mandatory system access projects but will take priority over other system undertakings and plans.

7. Alternatives Analysis

Since this is non-discretionary program, doing nothing is not a viable option as failure to perform the requested work would place PUC in violation of contractual obligations with the third party joint use partners. PUC reviews each application for new/revised attachments on a case by case basis to maximize system operation efficiency and cost effectiveness. Make ready work is reviewed and analyzed to minimize benefit for both parties while ensuring cost effectiveness.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	When partnered with third-party companies, the infrastructure required to support the communities in the region is minimized. Shared conduit structures and shared poles can be used in lieu of standalone systems, leading to less conflict in the field. PUC also reviews each request for new/revised attachments on a case by case basis to maximize system operation efficiency and cost effectiveness.
Customer Value	By permitting third-party companies to attach to PUC's infrastructure in a safe and economical manner, this investment influences communication companies to establish reliable communication systems throughout PUC's service territory and beyond. This contributes towards the economic growth and development of the region. In addition, PUC is able to offset project costs with revenue received from third party companies, thereby reducing the impact to customer rates.
Reliability	Any altering or upgrading of PUC's distribution line equipment to accommodate joint use partners will be completed such that reliability of the system is not negatively affected.
Safety	All work completed under this program considers safety as paramount by designing and installing to USF standards, PUC standards and/or specifics approved by a Professional Engineer.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Mandated Service Obligations* – PUC must meet contractual obligations to joint use partners as per existing Joint Use Agreements. By permitting third-party companies to attach to PUC's infrastructure, PUC is meeting its contractual obligations while also enabling customers throughout PUC's service area and beyond to benefit from the establishment of reliable communication systems.

ii. Secondary Drivers: *Increased Revenue* – PUC is partnered with multiple third-party communication companies in Sault Ste. Marie. All attachment points from third-party companies result in revenue for PUC, which is used to offset project cost and reduce the impact on rates.

iii. Information Used to Justify the Investment: PUC's Joint Use program is driven by contractual obligations and third party requests. Historical average expenditures within this program, excluding any unique large projects, inform forecast costs for this program. PUC also consults with third party communications companies on an ongoing basis to inquire about upcoming plans to ensure PUC is prepared. Additional information on PUC's consultation efforts with telecommunication companies can be found in Section 5.2.2.4 of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: New/revised joint use attachments will be reviewed against CSA, USF and PUC specific standards, and any infrastructure revisions will be completed using USF and/or PUC standards which are in line with industry standards allowing third parties reasonable access.

ii. *Cost-Benefit Analysis*: Options are considered on a case-by-case basis to provide the most practical and cost-effective solution for all parties.

iii. *Historical Investments & Outcomes Observed*: PUC routinely accommodates joint use projects within its service territory. These investments have enabled the successful connection of joint use projects to PUC's distribution equipment, reducing the need for standalone systems and leading to less conflict in the field. These investments have also enabled communication companies to establish reliable communications system throughout PUC's service territory and beyond, which has also contributed towards the economic growth and development within the region.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

CUSTOMER DEMAND – CITY PROJECTS

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Much of PUC's infrastructure is located within the municipal right of way in Sault Ste. Marie and some on the right of way owned by the Ministry of Transportation (MTO). The City of Sault Ste. Marie conducts complete road reconstructions, storm sewer replacement, curb, and asphalt work annually. During these projects, PUC's infrastructure may require relocation/replacement to support the excavation. Due to the Municipal Act and specifically the Public Service Works on Highways Act, PUC is required to relocate/replace infrastructure to support these projects upon request. A cost apportionment is identified in the Public Service Works on Highways Act as 100% material and 50% labour to be absorbed by the utility. The extent of the project areas varies from year to year depending on the City's overall plan and on the nature of PUC's infrastructure in the area being addressed. These projects typically occur between Spring and Fall with majority of the work occurring in early summer in preparation for road excavations.

For the forecast period, PUC assumes infrastructure relocation to accommodate road construction and realignment. In 2023, an underground vault requires relocation to accommodate the construction of Passchendaele Road, multiple pole relocations are required to accommodate a new sidewalk installation on Northern Avenue, and the completion of an overhead to underground relocation in the Bigham Street area is required to accommodate the construction of a Downtown Plaza on land that was previously a municipal right of way. Cost recovery for this program is typically based upon the cost apportionment set out in the Public Service Works on Highways Act.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Key factors that may affect timing include City approvals, roadway schedules, construction needs, and resource constraints. In addition, the schedule for these types of projects is largely dictated by the City/MTO and is therefore outside of PUC’s control.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ ‘000)					Forecast Costs ($ ‘000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	802	390	134	179	90	251	255	324	341	318
Contributions	(205)	(160)	(36)	(59)	(15)	(50)	(52)	(66)	(68)	(69)
Capital (Net)	597	230	98	120	75	201	203	258	273	249

4. ECONOMIC EVALUATION (EXPANSION PROJECTS)

This is not applicable.

5. COMPARATIVE HISTORICAL EXPENDITURE

Undertaking infrastructure relocation/replacement work to accommodate city projects is an ongoing activity for PUC, and the historical actual costs associated with this program are shown in Section 3 of this document. PUC also references the City of Sault Ste. Marie's five-year capital works program to identify the approximate scope of work and requirements for upcoming years. Historical values are used in conjunction with the City's five year plans to generate the forecast costs for this program. Examples of City Projects completed over the historical period are noted in the table below.

Table 2: Historical City Project Examples

Year	City Projects Completed
2018	• Black Road Reconstruction (2nd Line to 3rd Line) – Replacement of entire pole line to accommodate road widening
2019	• Black Road Reconstruction (McNabb to 2nd Line) – Replacement of poles to accommodate road widening. • McNabb Street Storm Sewer Replacement – Replacement of poles and underground infrastructure to accommodate a major storm sewer replacement.
2020	• Bay Street Reconstruction – Road realignment required multiple pole relocations and manhole restorations.
2021	• Downtown Plaza construction – relocation of overhead infrastructure to underground to accommodate the downtown plaza construction on previous municipal right of way. • Third Line East – Relocation of poles to accommodate road alignment and retaining wall installation.

6. INVESTMENT PRIORITY

This investment program is classed as a high priority since it is a non-discretionary program driven by third party requests and regulatory compliance. When infrastructure relocation/replacement requests are initiated under this program, they will be balanced with other mandatory system access projects but take priority over other system undertakings and plans.

7. ALTERNATIVES ANALYSIS

Since this is a non-discretionary program, doing nothing is not a viable option. PUC is required to relocate/replace infrastructure to accommodate City/MTO projects so that the projects can progress smoothly while minimizing or eliminating any potential safety hazards relating to PUC's infrastructure. For each request received under this program, alternatives are considered on a case by case basis at the time of project implementation, and the most practical solution is pursued considering safety, regulatory, system reliability, economics and customer relations.

8. INNOVATIVE NATURE OF THE PROJECT

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

Currently there are no Leave to Construct (LTC) approvals required as part of this program. However, if tasks arise that require LTC approval, PUC will follow required protocol.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	These projects typically have negligible effects on system operation efficiency, however PUC attempts to coordinate projects where possible to optimize efficiency and cost effectiveness. For example, when there is an opportunity to address future concerns, it may be advantageous from a cost perspective to address these needs at the time of relocation rather than returning at a late date to perform the work.
Customer Value	Customers benefit from PUC infrastructure located on municipal road allowances, minimizing cost for PUC to install electrical services. This cost saving will be reflected back to customers.
Reliability	Although the purpose of these projects is not to increase reliability, depending on the age of the assets being relocated/replaced, system reliability may be positively impacted due to the installation of new infrastructure based on current design standards.
Safety	All relocation/replacement work to accommodate City projects consider safety as paramount by designing and installing to USF standards, PUC standards and/or specifics approved by a Professional Engineer.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Mandated service obligations* – This program is mandatory, and the scope and timelines of the infrastructure relocation works required under this program are based on requests put forth by the City/MTO.

ii. Secondary Drivers: *Cost savings* - During relocation, there may be opportunities for PUC to update infrastructure and gain increased life and increased asset value at a reduced cost due to cost apportionment.

iii. Information Used to Justify the Investment: PUC is required to relocate infrastructure to support City/MTO projects. PUC references the City of Sault Ste. Marie's five-year capital works program to identify the approximate scope of work and requirements for upcoming years (to date, PUC has received plans up to and including 2023). Additionally, PUC consults with the City and MTO on an ongoing basis to inquire about upcoming plans to ensure PUC is prepared. Additional information on PUC's consultation efforts with the City of Sault Ste. Marie and other municipal stakeholders can be found in Section 5.2.2.2 of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

Demonstrating Accepted Utility Practice: When infrastructure relocation projects are required to accommodate City/MTO projects, all areas revised are reviewed and constructed in compliance with the latest CSA, USF, and/or PUC specific standards. In addition, any infrastructure relocation work presents an opportunity to update dated infrastructure to current standards which can address existing reliability and performance concerns.

i. *Cost-Benefit Analysis*: Project alternatives are considered on a case by case basis to provide the most practical and cost-effective solution for all parties.

ii. *Historical Investments & Outcomes Observed*: PUC routinely undertakes infrastructure relocation projects to accommodate City/MTO projects within its service territory. These investments have helped to ensure the successfully implementation of City/MTO projects in the past by eliminating any safety hazards relating to PUC's infrastructure. In addition, historical work completed under this program has also enabled PUC to update its infrastructure and gain increased life and increased asset value at a reduced cost due to cost apportionment.

iii. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. INNOVATION

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

REVENUE METERS

INVESTMENT CATEGORY:

SYSTEM ACCESS

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC owns and operates approximately 34,250 revenue meters, installed on its customers' premises for the purpose of measuring electric consumption and demand of connected load for the purpose of billing. All existing residential and general service (GS) customers (< 50 kW) were equipped with smart meters between 2009 and 2010.

This program includes expenditures related to the supply, installation and maintenance of revenue meters installed at each customer service point for retail settlement and billing purposes for all customers connected to PUC's distribution system. Revenue meters have four primary drivers, including (a) new meters for new customers, (b)) replacement of failed units, (c) reliability (elimination of meter types that have history of poor reliability) and (d) standardization.

The metering services included within this program are divided across 3 main sub-programs:

- **General:** This sub-program includes the installation of meters for new customers, replacement of faulty or expired meters, and the maintenance and upgrade of supporting metering infrastructure over the 2023-2027 forecast period. All new meters installed or replaced are 'iConA' remote disconnect smart meters. Meters to be purchased by PUC are forecast based upon historical information, quantity of meters expected to reach their seal expiry date, as well as the forecast new customer connections. PUC is looking to purchase approximately 400 new meters on average each year over the forecast period. This sub-program also includes costs associated with the purchase of smaller items that are used for maintenance and repairs, including but not limited to, meter seals, meter rings, disconnect sleeves, and metering wire. The number of meters and supporting metering infrastructure required for purchase will be reviewed each year by PUC to ensure the appropriate amounts are purchased.
- **Compliance Testing & Resealing:** In accordance with Measurement Canada Guidelines, PUC is required to reseal meters at specified intervals to ensure that a customer's electricity usage is metered accurately. Once a seal expires, the meter can no longer be used for billing purposes and must either have its seal period extended via compliance testing, or be replaced. Between 2023 to 2027, approximately 27, 968 of PUC's residential smart meters will subjected to testing by Measurement Canada using compliance sampling methods. This method sees compliance sample groups of approximately 1,000 meters that are tested. If the units pass the sample testing, their seal period will be extended and they can remain in service for the number of years as determined by the statistical sampling process. Additionally, in this same period 454 meters will expire and will need resealing. If the units fail sample testing, they will have to be removed from service and replaced by the end of the year that they are sampled in.
- **MIST Conversion for GS>50kW Customers:** A Metering Inside the Settlement Timeframe (MIST) is an interval meter from which data is obtained and validated within a designated settlement timeframe. In accordance with the DSC, PUC is required to install MIST meters for all general service customers that have a monthly average peak demand during a calendar

year of over 50 kW (i.e., GS > 50 kW). PUC is planning to complete the conversion of 78 existing GS>50 kW customers to MIST meters in years 2024 and 2025.

Since these investments are required by the Distribution System Code (DSC) and Measurement Canada guidelines, they are considered non-discretionary. By implementing this program, PUC can continue to accurately and correctly measure and bill customers for the electricity that they use and satisfy the OEB "Billing Accuracy" requirement to have 98% billing accuracy.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: The timing of the metering services included in this program are highly dependent on customer requests for new services as well as on the timing of metering system upgrade cycles. Other factors that might affect timing include material and resource constraints.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	174	62	500	208	173	207	509	527	243	255
Contributions	0	0	0	0	(20)	(20)	(21)	(21)	(22)	(22)
Capital (Net)	174	62	500	208	153	187	488	506	222	233

Note: The forecast capital contributions are expenditure that is collected from general customers where instrument transformers are required to be used with the primary metering. These are purchased by the customers as per PUC's Conditions for Service. The reason there are no capital contributions from 2018-201 is that no primary customer connections were carried out.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Metering services are ongoing annual expenditures. In the previous five historical years, PUC has purchased 1,590 meters to be used for new meter installs or meter replacements as part of this program. The following table shows the number of meters purchased each year. Meters are purchased into inventory and exact installation timing depends upon the needs of customers.

Table 2: Historical Number of Meters Purchased

	2018	2019	2020	2021	2022
Number of Meters Purchased	782	413	215	50	130

It is also noted that for the historical period 2018-2021 that there were no capital contribution amounts received although it is regularly budgeted for. This reflects the fact that there were no larger or primary customer service connections in which the customer is required to purchase their own instrument transformers in alignment with PUC Conditions of Service.

PUC considered historical expenditure, existing meter information, forecast customer needs, inflation, and other supply chain and material cost factors to generate forecast costs under this program.

6. Investment Priority

This investment program is classed as a high priority due to the obligation to connect new customers and the need to comply with mandated service obligations as defined by the DSC and Measurement Canada.

7. Alternatives Analysis

This investment is non-discretionary. No alternatives were considered since failure to perform the work to install, repair, replace and/or reseal meters would be in violation of the DSC and Measurement Canada Guidelines, and has the potential to negatively impact the reliable source of billing settlement data.

8. Innovative Nature of the Project

There is nothing innovative in this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	To enable cost efficiencies, PUC will look to purchase the new meters and associated equipment in bulk. Additionally, through addressing meters that are expiring, PUC will have reduced the number of meters that would be susceptible to unexpected failure and therefore reduce the cost for having to reactively repair these meters. Metering technology also supports the efficient and effective operation of PUC's system, and the metering services under this program will increase operational efficiency by reducing the number of manual reads.
Customer Value	For new meter installations as part of customer connection requests, the primary benefit for the customer is access to the

Primary Criteria for Evaluating Investments	Investment Alignment
	distribution system thereby meeting customers' power needs. Additionally, by upgrading and renewing existing meters that are expiring, this will ensure that customer meters continue functioning, capturing accurate electricity usage, and therefore enabling PUC to produce an accurate bill. Customer also have the ability to monitor their historical consumption through the PUC Customer app.
Reliability	Revenue meters have no impact on reliability performance on the feeder or at the customer location. However, by installing new meters that are up to current standards, this ensures that the reliability of the meters themselves continues to be maintained, thus enabling a reliable source of billing settlement data. All meters have last gasp functionality which in turn enables emergency response and outage restoration activities more effectively.
Safety	New meters will meet all safety standards.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Mandated Service Obligations* - The main driver for this program is PUC's obligation related to metering services as defined by the DSC and Measurement Canada. PUC is obligated to install and maintain meters at all customer connection points from both residential and commercial customers. By accommodating new connection requests and by replacing meters that have expired with new meters, PUC ensures that it complies with its obligations to provide, install, and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distribution system.

ii. Secondary Drivers*: Failure Risk* - By addressing expired meters, this reduces the risk of the meters failing and ensures the continued delivery of reliable and accurate bills.

iii. Information Used to Justify the Investment*:* New meter installations are mandatory investments arising from customer requests for new service connections, therefore customer requests are the source of information used to justify the new meter installations. PUC also collects and tracks data on its existing meters, and this information is used to determine when a meter requires testing, resealing or replacing.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital *investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).*

i. *Demonstrating Accepted Utility Practice*: PUC plans and executes its metering program to accommodate customer requests and comply with regulations. All new meters installed comply with the latest standards and regulations, and all metering services will be carried out in accordance with PUC's standards and practices.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Historical Investments & Outcomes Observed:* This historical costs and number of meters replaced during the historical period are detailed in sections 3 and 5 in part A of this document. Through its metering program, PUC has been able to continue to accurately bill customers.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing innovative in this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

UNPLANNED OH RENEWAL (FORCED)

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

The unplanned overhead (OH) renewal program is intended to cover costs associated with capital asset renewal from unplanned occurrences, typically resulting from weather related occurrences and/or vehicle accidents. When an unplanned occurrence materializes, PUC reviews the situation and determines whether a repair (maintenance budget) is adequate or if a complete replacement of the asset is warranted. When a complete replacement is warranted, PUC will replace the asset to today's standards, where feasible.

The number of customers affected by each failure is dependent on the location of the failure and the assets affected. For example, if a single distribution transformer fails, the customers affected should be limited to approximately 15. If the asset failed is a distribution pole supporting the sub transmission line (34.5kV), the customers affected could be up to 50% of the City. The number of customers immediately affected is not within PUC's control. PUC attempts to limit the number of customers that experience extended outages by switching, repairing and/or replacing assets.

For the forecast period, PUC has estimated the average number of assets that may need replacement based on historical failure information. The following table highlights the estimated number of replacements based on asset type. To be clear, as this is a reactive program, it is hard to predict the exact and type of assets that will need to be replaced on an unplanned basis. These figures are provided based on historical information and will likely be change.

Table 1: Estimated Number of Replacements by Asset Type

Asset Class	2023	2024	2025	2026	2027
Poles	15	15	15	15	15
Pole mount transformer	15	15	15	15	15
Fused switches	4	4	4	4	4
Disconnect switches	1	1	1	1	1

2. Timing

i. Start Date: January 2023

ii. In-Service Date: 2023 - 2027

iii. Key factors that may affect timing: Forced (reactive) replacements are prioritized and therefore no factors should affect timing.

3. Historical and Forecast Capital Expenditures

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	244	357	304	457	293	314	318	324	341	318
Recoverable[1]	74[2]	(156)	(163)	(86)	(37)	(38)	(39)	(40)	(41)	(41)
Capital (Net)	318	201	141	371	256	276	279	284	300	277

[1] The recovery rate is around 15% from vehicle accident poles.
[2] The positive removal amount in 2018 is the reversal of some uncollectable invoicing from prior years.

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PUC compares historical values for each category to budget for a recent average. As this budget is dependent on externally driven aspects such as weather and traffic accidents, the expenditures are considered on an annual basis and become difficult to predict. Between 2019 and 2021, 52 poles and 45 pole mount transformers were replaced, with total costs around $734,000 including recoverable, which averages around $245,000 per year.

6. Investment Priority

This is a high priority investment and falls under non-discretionary category. Projects under this investment are on top of PUC's list because they arise from system outages and safety concerns. Using PUC's prioritization process, this project ranks 1st out of 11.

7. Alternatives Analysis

PUC considered the following options:

- **Option 1: Proactive Replacement of Overhead Assets** - Although PUC tests assets and performs regular system inspections to understand where majority of concerning assets are located, completely eliminating system outages through planning is not possible. External factors such as weather or accidents can cause unplanned outages and reactive measures are required to respond to those situations, therefore this is not a viable option.
- **Option 2: Reactive Repair/Replacement of Overhead Assets** - There are no other practical alternatives to be considered because of the reactive and high priority nature of these projects. It is essential to replace affected overhead assets as soon as possible to ensure safety and access to reliable electricity. A reactive approach to safe asset failures extends the assets useful life to the point of failure. Balancing the value to the extended life and the incremental costs due to the reactive approach is considered to optimize replacements.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	This is not applicable.
Customer Value	Through this investment, customers will have reduced outage times and safety concerns managed in a timely fashion.
Reliability	This investment has a significant impact on reliability performance. Although these projects do not impact the frequency of outages (SAIFI), they do limit the size of the extended outage and reduce the duration of outages (SAIDI, CAIDI).
Safety	Safety is a driving factor for this investment. By attending the site, making it safe, and replacing the failed infrastructure, PUC reduces hazards for both the public and the workers. Final installations are then completed as per CSA, USF and/or PUC specific standards.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Failure risk* - When a fault occurs, it typically causes an outage for several customers. PUC strives to provide a reliable system for all its customers by attending to the site as soon as possible.

ii. Secondary Drivers: *Safety* - Safety to the public and workers when a fault occurs in the system is a driving investment factor. Although the system is protected through fusing, reclosers, relays, and breakers, it is imperative that PUC assesses the site to ensure safety.

iii. Information Used to Justify the Investment*:* This investment is required to provide a safe and reliable electrical system to customers and mitigate the risk of PUC's reliability statistics from decreasing by limiting the duration of outages.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: Emergency replacement of assets are constructed in accordance with USF and/or PUC specific standards, which are in line with industry standards allowing third parties reasonable access. Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or PUC standards. Final installation will be completed as per CSA, USF and/or PUC specific standards.

ii. *Cost-Benefit Analysis:* There are no other cost-effective and practical alternatives to this investment.

iii. *Historical Investments & Outcomes Observed:* Although PUC compares historical values for each category to budget for a recent average number of unplanned outages, it is difficult to accurately project due to the unpredictable nature of the outages. In the past, these projects have had minimal long-term effects on O&M costs. Asset replacements due to failure do not require significant O&M attention in the future.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

UNPLANNED UG RENEWAL (FORCED)

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

The unplanned underground (UG) renewal program is intended to cover costs associated with capital asset renewal from unplanned occurrences, typically resulting from failed underground and/or pad mounted assets. When an unplanned occurrence materializes, PUC reviews the situation and determines whether a repair (maintenance budget) is adequate or if a complete replacement of the asset is warranted. When a complete replacement is warranted, PUC will replace the asset to today's standards, where feasible.

Impacts to customer vary on a case-to-case basis. Some examples are extended outages on residential homes heated using electrical heat, commercial properties with extended outages during regular business hours and critical customers who rely on electricity for emergency services. Due to the unknowns and the possibility for loss of electricity being detrimental, PUC responds to each case effectively with the goal of minimizing the duration of outages for all customers.

For the forecast period, PUC has estimated the number of assets that might fall under the forced underground renewal program. To be clear, as this is a reactive program, it is hard to predict the exact and type of assets that will need to be replaced on an unplanned basis. These figures are provided based on historical information and will likely be change.

Table 1: Estimated Number of Replacements by Asset Class

Asset Class	2023	2024	2025	2026	2027
Pad mount transformer	6	6	6	6	6
Submersible transformer	7	7	7	7	7

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Forced (reactive) replacements are prioritized and therefore no factors should affect timing.

3. Historical and Forecast Capital Expenditures

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	208	303	344	388	322	376	382	388	409	382
Contributions	(17)	(2)	0	(19)	0	0	0	0	0	0
Capital (Net)	191	301	344	369	322	376	382	388	409	382

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PUC compares historical values for each category to budget for a recent average. Since this budget is dependent on unexpected failures, the expenditures are considered on an annual basis and become difficult to predict. Limited investment into aging underground infrastructure result in increased forced replacement and maintenance costs.

Between 2019 and 2021, five (5) mini pad, 13 pad mount, and 21 submersible transformers were replaced, for a project total cost of approximately $786,000, making the average yearly cost of forced underground renewal projects to be around $262,000.

6. Investment Priority

This is a high priority investment and falls under non-discretionary category. Using PUC's prioritization process, this project ranks 1st out of 11. Projects under this investment are on top of PUC's list because they arise from system outages and safety concerns.

7. Alternatives Analysis

PUC considered the following options:

- **Option 1: Proactive Designing of Underground Assets** - Proactively designing all potential failure assets or designing asset on the spot after the failure is not practical and therefore not a viable option.
- **Option 2: Reactive Repair/Replacement of Underground Assets** - There are no other practical alternatives to be considered because of the reactive and high priority nature of these projects. It is essential to repair/replace affected assets as soon as possible to ensure safety and access to reliable electricity. This investment also has some cost-savings opportunities for PUC. A reactive approach to safe asset failures extends the assets useful life to the point of failure. Balancing the value to the extended life and the incremental costs due to the reactive approach is analysed to optimize replacements.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	This is not applicable.
Customer Value	Through this investment, customers will have reduced outage times and safety concerns managed in a timely fashion.
Reliability	This investment has a significant impact on reliability performance. Although these projects do not impact the frequency of outages (SAIFI), they do limit the size of the extended outage and reduce the duration of outages (SAIDI, CAIDI).
Safety	Safety is a driving factor for this investment. By attending the site, making it safe, and replacing the failed infrastructure, PUC reduces hazards for both the public and the workers. Final installations are then completed as per CSA, USF and/or PUC specific standards.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Failure risk* - When a fault occurs, it typically causes an outage for several customers. PUC strives to provide a reliable system for all its customers by attending to the site as soon as possible.

ii. Secondary Drivers*: Safety* - Safety to the public and workers when a fault occurs in the system is a driving investment factor. Although the system is protected through fusing, reclosers, relays, and breakers, it is imperative that PUC assesses the site to ensure safety.

iii. Information Used to Justify the Investment*:* This investment is required to provide a safe and reliable electrical system to customers and mitigate the risk of PUC's reliability statistics from decreasing by limiting the duration of outages.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital *investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).*

i. *Demonstrating Accepted Utility Practice*: Emergency repair and replacement of assets are constructed in accordance with USF and/or PUC specific standards, which are in line with industry standards allowing third parties reasonable access. Emergency replacements are typically constructed like-for-like, but when practical, they are constructed to USF and/or PUC standards. Final installation will be completed as per CSA, USF and/or PUC specific standards.

ii. *Cost-Benefit Analysis:* There are no other cost-effective and practical alternatives to this investment.

iii. *Historical Investments & Outcomes Observed:* Although PUC compares historical values for each category to budget for a recent average number of unplanned outages, it is difficult to accurately project due to the unpredictable nature of the outages. In the past, these projects have had minimal long-term effects on O&M costs. Asset replacements due to failure do not require significant O&M attention in the future.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

OH RENEWAL – TRANSFORMERS (PCBS)

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC owns, operates and maintains 1,850 pole mounted transformers, all of which are oil filled. Historically, a chemical compound known as a polychlorinated biphenyl (PCB) was widely deployed in dielectric and coolant fluids in the manufacturing of oil filled electrical apparatus. However, this manufacturing practice was discontinued when it became evident that PCBs build up in the environment and exposure to high levels can cause harmful health effects.

In 2008, Environment Canada enacted Federal Regulation *SOR 2008-273 – PCB Regulations* which dictates requirements to replace equipment with oil containing PCBs by various dates depending on the PCB concentration. The regulations set a deadline of December 31, 2025 to eliminate concentrations of PCB's greater than 50 ppm in pole mounted, oil filled, electrical transformers. This project addresses the removal and replacement of the remaining overhead pole mounted transformers with PCB concentrations greater than 50 ppm within PUC's distribution system.

PUC undertook a PCB transformer testing program in 2020/2021 to determine the number of remaining pole mounted transformers within its distribution system with PCB concentrations greater than 50 ppm. To date, approximately 73% (1,350 of 1,850) of PUC's transformers have been inspected and tested, and PUC has confirmed that 11% (145) of transformers have PCB concentrations greater than 50 ppm. PUC is planning to inspect and test the remaining transformers over the period from 2023 to 2024, however based on an extrapolation of the testing results, PUC anticipates that approximately 200 transformers (i.e., 11% of the total pole mount transformer population) will have PCB concentrations greater than 50 ppm and therefore need to be replaced by December 2025. As a result, PUC is planning to replace approximately 67 PCB-contaminated transformers annually between 2023 to 2025 with new standardized transformer equipment in order to comply with PCB regulations.

To take advantage of timing, cost and resource efficiencies, PUC is also planning to replace end-of-life poles, which are associated with the transformer forecast to be replaced, as part of this project.

By implementing this project, PUC will ensure continued compliance with environmental legislation while also mitigating the health, environmental and safety risks associated with PCB contamination >50 ppm.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2025

iii. Key factors that may affect timing: Material and resource constraints may affect timing, however PUC intends to complete designs and order materials as required. Due to the significant delay on transformer delivery (quoted up to 2 year delivery time), this may impact the program and how PUC is able to meet the December 31, 2025 deadline.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	0	0	0	0	0	711	721	734	0	0
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	711	721	734	0	0

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

As part of this project, the average pole mount transformer replacement cost including a portion of pole replacements is on average $8,500 per location. Since this is a new separate project for PUC, there is no direct comparative historical expenditure information.

However, PUC has replaced pole mounted transformers historically as part of other projects or programs, at an average cost of $5,000 per replacement for the transformer only or $10,000 when the pole requires replacement.

6. Investment Priority

This investment is classed as a high priority due to the obligation to eliminate concentrations of PCB's greater than 50 ppm in electrical transformers by December 31, 2025, in accordance with the Federal PCB Regulations.

7. Alternatives Analysis

This investment is non-discretionary. No alternatives are considered, since failure to remove PCB contaminated distribution line equipment would place PUC in violation of Federal PCB Regulations and result in increased public health, environmental and safety risks.

8. Innovative Nature of the Project

There is nothing innovative in this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Planned replacement of these pole mounted transformers rather than reactive replacement at the time of a leak or catastrophic failure can usually be organized as part of regular work and therefore not subject to overtime premiums. Planned replacements will also eliminate the risk of any additional work or costs associated with potential PCB contamination.
Customer Value	The potential health and safety hazards to customers and the public associated with PCB transformers are being mitigated via the execution of this project. Remediation of PCB contamination is costly and therefore minimizing the exposure provides additional long term customer value.
Reliability	This project will replace old PCB contaminated transformers with new equipment. As the existing transformer is beyond its useful life, the new transformer should improve reliability. In addition, the replacement of EOL poles as part of this project will also improve the overall reliability of the system.
Safety	The potential health, environmental and safety risks associated with PCB transformers are being mitigated via the execution of this project.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Mandated Obligations Mandated Service Obligations* – the main driver for this project is the Federal Regulation SOR 2008-273 which dictates that all pole mounted equipment with oil containing PCBs in concentrations of 50 ppm or greater must be removed from service by 2025.

ii. Secondary Drivers*: Failure Risk* – By addressing the contaminated pole mounted transformers, this eliminates the risk of these transformers leaking or failing and ensures PUC's ability to guard worker, public and environmental safety and while maintaining system reliability. All transformers being replaced within this program are beyond their useful life and are subject to failure. Replacement will help improve reliability.

iii. Information Used to Justify the Investment*:* PUC undertook a PCB transformer testing program in 2020/2021 to determine the number of remaining pole mounted transformers within its distribution system with PCB concentrations greater than 50 ppm. Approximately 73% of PUC's transformer population has been inspected and tested to date, and the results were used to identify the transformers that require replacement by the December 31, 2025 deadline.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: PUC is executing this project to comply with regulations. All new pole mounted transformers purchased will comply with the latest standards and regulations, and all installations will be carried out in accordance with PUC's standards and the *ON Reg. 22/04* to ensure no undue safety hazards. The transformers will be replaced with PUC's current standards for pole mounted transformers used throughout PUC's system.

ii. *Cost-Benefit Analysis:* This is not applicable.

iii. *Historical Investments & Outcomes Observed:* Pole mounted transformers have been replaced historically as part of other projects or programs, but this is the first project focused on eliminating pole mounted transformers. Historical information from other projects has been used to create a program budget. Estimates will be reviewed for accuracy during detailed design.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that *allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.*

There is nothing innovative in this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

OH RENEWAL – VOLTAGE CONVERSION

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Approximately 30 years ago, PUC started a program to gradually upgrade its distribution system from 4.16 kV to 12.47 kV. When the existing 4.16 kV infrastructure reaches the end of its service life, rather than like for like replacement of 4.16 kV rated equipment with 4.16 kV rated equipment, the voltage is upgraded to 12.47 kV, which results in greater operating efficiency. A vast majority of the distribution system has already been upgraded to 12.47 kV and at present relatively small pockets of service area with 4.16 kV network remain.

PUC has approximately 22 km of 4.16 kV circuits and two 4.16 kV distribution stations (Substations #4 and #5) remaining in service. Most of the remaining distribution infrastructure operating at 4.16 kV is at the end of its service life and the poor condition of equipment has been resulting in frequent equipment failures with adverse impacts on reliability. Maintaining a distribution system with two operating voltages has also resulted in duplication of lines and economic inefficiencies due to system energy losses.

As part of this Voltage Conversion program, PUC is proposing to complete its long standing voltage conversion initiative by retiring the remaining network equipment operating at 4.16 kV from the grid. This includes replacing two sections of 4.16 kV circuits with 12.47 kV circuits (detailed below), disconnecting Substations #4 and #5, and removing all remaining 4.16 kV circuits from service. In the 2023 Test Year, the following activities are planned:

- **Railway Tracks (Elizabeth to Simpson):** This project includes the replacement of *1,400 m* of overhead end of life 4.16 kV circuit with 12.47 kV circuit from Elizabeth Street to Simpson Street. The circuit is primarily 3phase and will be reduced to single phase further increasing reliability and reducing operations and maintenance costs. There are eighty-two (82) customers immediately impacted by the project.

Figure 1: Railway Tracks (Elizabeth to Simpson) – Project Area

Figure 2: Typical Pole in Project

- **Pim (Ontario to Sub 4):** This project includes the replacement of *765 m* of overhead end of life 4.16 kV circuit to 12.47 kV circuit from Ontario Street to Substation 4. Although this project does not directly service any customers, removal of the existing 4.16 kV line will permit PUC to decommission Substation #4 and reduce reliability concerns and ongoing operations and maintenance costs.

Figure 1: Pim Street (Ontario to Sub 4) - Project Area

Figure 2: Typical Pole in Project

- **Installation of 34.5kV switch point:** This project includes the installation of a new 34.5 kV switching point in an area adjacent to Substation #4 (shown in Figure 5 below). The installation of a 34.5 kV switching point will provide PUC the same level of switching flexibility currently available in the 34.5 kV sub-transmission system.

Figure 3: 2012 Photo of Area Adjacent to Substation #4

PUC is also planning to disconnect Substations #4 and #5, which will increase safety, reliability and reduce operation and maintenance costs.

Completion of PUC's long standing voltage conversion project during this filling period is expected to bring benefits in a number of ways. Firstly, these remaining circuits once transferred over from 4.16 kV to 12.47kV, will allow for the connection of DER as the newer 12.47 kV feeders include the necessary protection systems to support their connection. Secondly, the elimination of multi-circuit distribution lines along many streets eliminates the need to stock multiple types of equipment and should lead to a less complex and better hardened system better able to withstand more severe wind and ice loading weather conditions expected with climate change. Additionally, removal of the remaining 4.16 kV distribution lines will permit the disconnection of the two remaining 4.16 kV substations improving system safety and reliability. Furthermore, the reduction in electrical losses from retiring the remaining 4.16 kV infrastructure and with the move to higher voltage are expected to bring advantages from an environmental perspective.

Although Substations #4 and #5 will be disconnected during this DSP period, decommissioning of the substations has been deferred to the next cost of service period.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2023

iii. Key factors that may affect timing: Project implementation may be delayed depending on unplanned or higher priority work arising, resulting in resource constraints.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	257	557	296	640	663	864	0	0	0	0
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	257	557	296	640	663	864	0	0	0	0

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PUC has extensive historical information on voltage conversion projects and projects of similar nature. Using this information, PUC can reasonably estimate each project without a detailed design being completed beforehand. For example, according to 2017 estimates, the conversion project along McDonald (Pine to Sub 4) cost around $100,000, whereas the McDonald (Lake to Moluch) project costs were around $210,000. Since each project is unique (e.g., some projects require complete rebuilds of the pole lines while others are mostly removal with some replacements, some projects have vehicle accessibility while others are in difficult to access rear lots, etc.), average costs are difficult to identify.

6. Investment Priority

Using PUC's prioritization process, this project is ranked 3rd out of 11 projects. In the prioritization process, project interdependence is the main contributor to the ranking of the project, meaning that not proceeding with this project will negatively impact the ability to complete other future planned work. It is important to complete the remaining conversion projects in order to simplify, standardize and improve the overall performance and efficiency of the distribution system.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Do Nothing** – System assets planned for replacement under this program are nearing or beyond their anticipated lifespan, making them unreliable and unsafe in some situations. Replacing these assets is essential in maintaining a safe and reliable distribution system, therefore doing nothing is not an option. Since most of the conversion and replacement has already taken place, it is important to complete the remaining conversion projects.
- **Option 2: Voltage Conversion and Station Replacement** – This option includes retiring the remaining network equipment operating at 4.16 kV from the grid, upgrading all the remaining line sections to 12.47 kV, and replacing Substation 4 with a 34.5 kV switch point. This is the preferred option as it will enable PUC to replace end of life poor condition equipment with new standardized equipment while also reducing electrical losses, eliminating multi-circuit distribution lines, and enabling future opportunities for the connection of DER and EVs.

8. Innovative Nature of the Project

Although voltage conversion projects are not considered innovative for PUC, once these circuits are transferred over from 4.16 kV to 12.47 kV, this will allow for the connection of distributed energy resources (DER) and electric vehicle (EV) charging as the newer 12.47 kV feeders include the necessary protection systems to support their connection.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that *it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).*

Currently there are no Leave to Construct (LTC) approvals required as part of this program. However, if tasks arise that require LTC approval, PUC will follow the required protocol.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Upgrading 4.16 kV rated equipment to 12.47 kV equipment will result in greater operating efficiency, reduced power losses, and standardized equipment allowing for purchasing efficiencies. It will also eliminate the last of many complex multi-circuit distribution lines and the need to stock multiple types of equipment.
Customer Value	Customers will benefit from continued access to safe and reliable electricity. The conversion will also enable future opportunities for DER and EV charging.
Reliability	This investment will have a positive impact on system reliability since old poor condition assets are being replaced with new assets with lower failure risk.
Safety	To convert voltages, many transformers will require replacement. The framing, inclusive of separations on existing poles may be well below current standards. In order to ensure separations are achieved and working space is considered, many poles beyond their useful life will require replacement. In replacing poles, safety is increased for both the work (working space) and the public (new asset). Additionally, removal of the 4.16 kV distribution lines will permit retiring of the two remaining 4.16 kV substations improving system safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Safety & Reliability* - Most of the remaining distribution infrastructure operating at 4.16 kV is at the end of its service life and the poor condition of equipment has been resulting in equipment failures with adverse impacts on reliability. The two remaining 4.16 kV substations have surpassed their useful life creating increased safety and reliability risks. Decommissioning the existing substations is not feasible without the complete system conversion. With stations being replaced with higher distribution voltage to meet industry standards, the system will be more dependable, and customers will have access to reliable electricity.

ii. Secondary Drivers: *Cost effectiveness* - The conductors are currently operating at a lower voltage (4.16 kV vs. 12.47 kV), which requires a larger amount of current to be fed through conductors to supply the same amount of power. Voltage conversion will result in a reduction in losses. Additionally, standardizing material allows PUC to store less material, requiring less inventory.

iii. Information Used to Justify the Investment: PUC's Voltage Conversion Program is a long standing program that is informed by PUC's asset management process (Section 5.3.1 of the DSP) and asset lifecycle optimization practices (Section 5.3.3 of the DSP). As detailed in PUC's ACA report included in Appendix H of the DSP, PUC has approximately 22 km of 4.16 kV line and two 4.16 kV distribution stations in service (Substations 4 and 5). Most of the remaining distribution infrastructure operating at 4.16 kV is at the end of its service life and the poor condition of equipment has been resulting in frequent equipment failures with adverse impacts on reliability. By allowing poor condition and end-of-life equipment to be replaced, this investment prevents the power supply reliability from degrading below PUC's targets. The planned replacement and conversion projects are essential in maintaining a reliable distribution system for the customers.

3. INVESTMENT JUSTIFICATION

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: Replacements will be constructed using USF standards, PUC standards, and/or specifics approved by a Professional Engineer.

ii. *Cost-Benefit Analysis*: There are no other practical and cost-effective alternatives for projects under this investment that provide the same level of benefits to customers.

iii. *Historical Investments & Outcomes Observed*: PUC has completed several voltage conversion projects historically and has observed many positive outcomes from these projects including but not limited to, improved system efficiency, reduction in losses, and increased standardization requiring less inventory. When end-of-life poor condition assets are replaced as part of these voltage conversion projects, this also results in maintained or improved system reliability.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

Although voltage conversion projects are not considered innovative for PUC, once these circuits are transferred over from 4.16 kV to 12.47 kV, this will allow for the connection of DER and EV charging as the newer 12.47 kV feeders include the necessary protection systems to support their connection.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

OH RENEWAL – RESTRICTED CONDUCTOR

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC has identified #6 copper overhead primary conductor as "restricted wire". Due to the nature of the conductor (i.e., small and constructed of copper), the conductor becomes elongated and brittle over years of use, making it prone to failure through breaking. One of the consequences is an increased frequency and duration of outages. Additionally, because of its potential to break with minimal disturbances, line workers are 'restricted' to only work on these circuits in a deenergized state. The time required to make the worksite safe comes at the cost of more frequent planned outages and higher associated operational costs.

When #6 is replaced, it is upgraded to #2 aluminum conductor steel-reinforced cables (#2ACSR), which are high-capacity and high-strength conductors. Generally, along with restricted conductors, any poor condition and end of life assets such as poles, cross arms, pole mount transformers, fused switches and/or disconnect switches are also addressed at the same time to gain economies of scale.

The typical age of installation in areas where #6 conductor is present is typically mid 1970's or earlier, making the assets 50 years or older. This is generally why restricted conductor projects involve more than simply replacing the conductor, resulting in efficient long-term solution and economies of scale. The following table highlights the areas with #6 conductor that are planned to be addressed over the forecast period as part of this restricted conductor replacement program:

Table 1: Proposed Restricted Conductor Replacements

Year	Areas Addressed for Restricted Conductor Replacement
2023	Bloor Street West, Langdon/Sydenham/Cheshire/Henry/Kingsford/Murton Phase 1
2024	Langdon/Sydenham/Cheshire/Henry/Kingsford/Murton Phase 2, Herkimer/Victoria/Hess, Brule Road, Old Goulais Bay Rd.
2025	St. Basils Dr/Walters St., Fournier Rd./River Rd.
2026	Nettleton Street, 4th Line E, Fish Hatchery Road/Landslide Road, Trunk Rd. (East of Fournier)
2027	None

The two key projects planned for the 2023 Teat Year are described further below:

- **Bloor Street West:** This project includes the replacement of 300 m of #6 copper overhead primary conductor located at Bloor Street West, immediately affecting 16 customers. The area is front lot accessible.

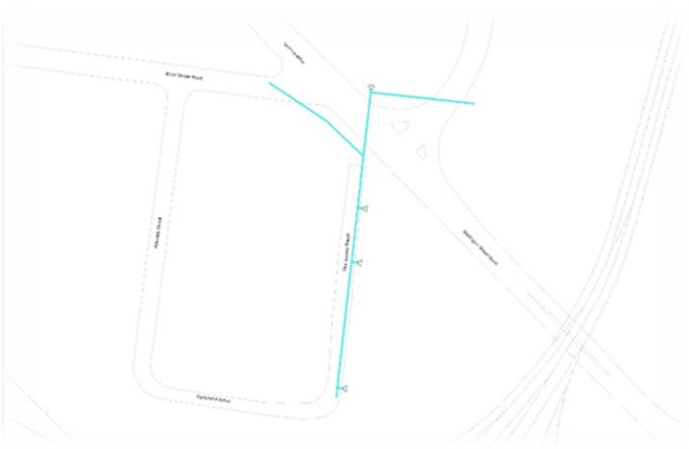


Figure 1: Bloor Street West - Project Area

Figure 2: Typical Pole in Project

- **Langdon/Sydenham/Cheshire/Henry/Kingsford/Murton Phase 1:** This project includes the replacement of 980 m of #6 copper overhead primary conductor located on multiple streets in the area of Langdon Road. The area is front lot accessible immediately affecting 95 customers.

Figure 3: Langdon Road Area - Project Area

Figure 4: Typical Pole in Project

Completing the proposed work under this program will eliminate safety risks associated with the #6 conductor, while also having a positive effect on reliability and system operation efficiency.

2. Timing

i. Start Date: January 1, 2023

ii. In-Service Date: December 31, 2023

iii. Key factors that may affect timing: Project implementation may be delayed depending on unplanned or higher priority work arising, resulting in resource constraints.

3. Historical and Forecast Capital Expenditures

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	930	406	620	222	878	362	1,288	517	834	0
Contributions	0	(14)	(52)	0	0	0	0	0	0	0
Capital (Net)	930	392	568	222	878	362	1,288	517	834	0

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Using historical information, the length of restricted conductor to be replaced, single phase versus three phase, quantity of poles, quantity of transformers and other unique criteria, PUC can reasonably estimate each project without a detailed design being completed beforehand. However, the costs per length on a project-by-project basis are extremely variable and are dependent on many factors. Factors include vehicle accessibility, condition of pole and associated infrastructure and weather conditions during construction. Due to this, it difficult to utilize a single project or even a single year to analyse costs.

6. Investment Priority

Using PUC's prioritization process, this project is ranked 4th out of 11. In the prioritization process, Public Safety is the main contributor to the ranking of the project. Due to the nature of the hazard, it is important to continue to remove restricted conductor from service but working around restricted conductor can be handled through work procedures until all restricted conductors can be removed.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Do Nothing** – Although it is possible to work around a restricted conductor temporarily, not removing it will cause the project to be extended, resulting in increased associated operation and repair costs. Additionally, not replacing restricted conductors can pose serious safety risks for workers and the public. Therefore, this is not a practical and viable option.
- **Option 2: Replacement of Restricted Conductors & Associated Infrastructure** – This option will remove restricted wire and generally replace it with new #2ACSR primary conductor. This option also optimizes mobilization costs to replace aged infrastructure at the same time limiting multiple visits and additional outages to customers. This is the preferred option as it will enable PUC to eliminate the safety risks associated with this conductor, while also having a positive effect on reliability and system operation efficiency.
- **Option 3: Replacement of Restricted Conductors** – This option will remove restricted wire and generally replace it with new #2ACSR primary conductor. This option reinsulates and replaces conductor like-for-like. Although the safety risk of the conductor is removed, the safety and reliability risks of the aged infrastructure remains with additional mobilization costs required. As a result, this option was discarded.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

Currently there are no Leave to Construct (LTC) approvals required as part of this program. However, if tasks arise that require LTC approval, PUC will follow the required protocol.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Removing the restricted conductor will have a positive effect on system operation efficiency since it will reduce the system downtime and the inconvenience associated with routinely isolating these circuits when work is required. During the removal of restricted conductors, associated infrastructure (insulators, poles, transformers, etc.) are also reviewed and addressed if required. This leads to asset management efficiencies and cost savings for PUC.
Customer Value	Customers benefit from a safer, more reliable system and more cost effective electrical distribution system. Reducing downtime of PUC's system also contributes positively towards economic development in the region.
Reliability	Removal of restricted conductor and replacement of associated infrastructure that is in poor condition and beyond its useful life will reduce the risk of outages and downtime, leading to a more reliable system.
Safety	Safety is a driving factor for this investment. Removal of restricted conductor eliminates the risks associated with routinely isolating circuits to provide adequate worker safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Safety* – Safety is the primary driver for this project. The restricted conductor can become brittle and break with minimal disturbances. This becomes even more of a concern when PUC and/or third-party contractors are working on infrastructure attached to PUC's poles with restricted conductor present as additional forces to the conductor further expose failure points. Eliminating the restricted conductor will eliminate the safety hazards associated with this equipment and make the workplace safer.

ii. Secondary Drivers: *Economic Efficiency* - PUC's current practice for work on poles containing restricted conductor is to take an outage if staff, contractors, or joint use telecom parties are working on or below the conductor. By eliminating restricted conductors, PUC reduces the requirements to take outages.

iii. Information Used to Justify the Investment: It is common knowledge and well documented across the utility sector that the #6 conductors, over time, become brittle and present a safety risk if not adequately managed through costly customer impactive work methods. This is a known risk that is being proactively addressed through implementation of this program.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: Given the known safety risks associated with these small copper conductors, most utilities have already eliminated or are in the process of eliminating restricted conductor where it still exists. Replacements will also be constructed using USF standards, PUC standards, and/or specifics approved by a Professional Engineer.

ii. *Cost-Benefit Analysis:* Although doing nothing may be temporarily possible using work arounds, this can lead to increased risk and more expensive procedures in the near future. Therefore, there are no other practical and cost-effective long-term alternatives available to address the remaining restricted conductor in PUC's distribution system. During the design to replace the restricted conductor, a wholistic review of the area is completed to determine the most practical solution.

iii. *Historical Investments & Outcomes Observed*: PUC has completed several restricted conductor replacements historically and has observed many positive outcomes from these projects including but not limited to improved safety, maintained or improved system reliability, and improved operational efficiency. When end-of-life poor condition assets are replaced as part of these restricted conductor replacements, this also results in maintained or improved system reliability while also gaining economies of scale.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. INNOVATION

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this investment.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

OH RENEWAL – POLES

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC has a significant amount of overhead (OH) electrical infrastructure. Within that overhead infrastructure, PUC owns approximately 12,600 poles and are currently joint use on another 3,350 Bell Poles. Poles are classed as critical infrastructure due to the role they play in carrying OH assets that deliver safe and reliable electricity to their customers. PUC has an annual pole replacement program. PUC retains a third-party to perform pole testing on 1/7 of its poles annually that are ten years or older to determine poles that require immediate attention, short term attention, and continuous monitoring. The third-party testing results and field identification and inspection by staff are used to inform the asset condition assessment (ACA). This ACA is used to inform PUC's investment plan in unsafe poles. The asset life relative to the typical life cycle is determined on a case-by-case basis. Generally, deteriorated poles are beyond 45 years old, but some poles are identified as deteriorated prior to this due to ground line rot, infestation, woodpecker damage, etc.

PUC undertook an ACA in 2021, which has been used to help build the proposed plan. The full ACA report can be found in Appendix H of the DSP. As of 2021, 4.7% (590) wood poles are in poor condition and 4.6% (574) wood poles are in very poor condition. For the forecast period, PUC plans to replace approximately 60 wood poles per year. As well as replace the poles, PUC will also look to replace associated attachments at the same time. PUC strives to coordinate multiple programs together to optimize replacements. For example, a restricted wire program in the same area as multiple deteriorated poles will allow both programs to be completed at an overall reduced cost.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: 2023 - 2027

iii. Key factors that may affect timing: Projects with higher priority, resource and supply chain constraints.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	499	476	590	312	695	602	611	621	655	611
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	499	476	590	312	695	602	611	621	655	611

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs associated with pole replacements under this program are shown in Section 3 above. The historical information and factors such as inflation, supply chain and material cost factors into replacement costs. As all poles are different, it is difficult to predict a per pole cost on such a small quantity of poles. For the forecasted period, PUC has assumed an average cost of replacing a single pole is approximately $8,000.

6. Investment Priority

Using PUC's prioritization process, this project is ranked 5th out of 11 projects. In the prioritization process, Public Safety is the main contributor to the ranking of the project. Pole replacement projects are based on identification of deteriorated poles and level of risk associated with them in the field. They are one of the most critical pieced of infrastructure as they carry the critical assets that deliver the electricity supply to the customers.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Proactive Pole Replacement** – Dependent on the level of risk for the poles identified, some may be considered emergency replacements, short term replacements (<1year), or long-term replacements (<5years). The proposed proactive replacement of unsafe poles will ensure that the number of unplanned outages remain minimal by avoiding asset failures, so that the customers have access to reliable electricity for their needs. Costs also be reduced when compared with a completing all pole under a reactive program.
- **Option 2: Do Nothing/Reactive Replacement** – PUC does consider reactive replacement for some pole replacements. While this can be employed for unplanned and unexpected failure of poles, it is not sustainable to carry out for all pole replacements. Customers would experience longer and increased unexpected outages. In addition, replacing poles reactively generally incurs a premium as they are unplanned and inevitably are replaced outside normal hours and therefore resource costs increase. This ultimately would increase forced renewal costs.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Although this investment has minimal effect on system efficiency, failure to replace deteriorating poles might result in asset failure and system reliability concerns. This will have an overall negative impact on the efficiency of the distribution system at a given time. In addition, PUC is being efficient in its replacement plan by replacing other associated assets with the poles (conductor, pole-mount transformer, switches) that have also reached or approaching end of life, rather than return at a later date.
Customer Value	Customers located in the area of the identified deteriorated poles will benefit from the system reliability and safety being maintained at current levels, dependent on the nature of the pole. Additionally, proactive pole replacements reduce the cost in comparison to reactive replacements upon failure, reducing PUC's overall costs and minimizing impacts to customer's monthly bills.
Reliability	Reliability performance directly benefits from replacement of deteriorated poles as it reduces the likelihood of unplanned outages which typically result in longer duration outages. Optimal asset conditions are needed to maintain a safe and reliable distribution system. Replacing less than forecast program will cause increased safety and reliability risks as well as increased forced renewal costs.
Safety	Public and employee safety is a driving factor for this investment. Proactively replacing deteriorated poles minimizes the risk of pole failures that can cause potential maintenance and electrical hazards.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Failure risk* - Power supply reliability is the primary driver for this investment. Proactively identifying poles that are close to failure and replacing them minimizes the risk of asset failure. This reduces the risk of prolonged and uncontrolled power outages. Without pole replacements, PUC's reliability statistics would be negatively affected. By replacing the proposed amount of poles PUC will be able to maintain reliability levels.

ii. Secondary Drivers*: Public Safety* - Proactively replacing deteriorated poles reduces the risk of poles and/or live conductors falling to the ground and creating hazardous conditions for the community.

iii. Information Used to Justify the Investment*:* Recent ACA results has identified around 4.7% (590) of poles to be in poor condition and around 4.6% (574) of poles to be in very poor condition. By identifying and proactively replacing poles nearing their end of life and in deteriorated condition, PUC mitigates the risk of outages and provides a safe electrical system by controlling hazards. It is important that customers have access to a safe and reliable distribution system. The full ACA report can be found in Appendix H of the DSP, and additional information on PUC's asset management process is included in Section 5.3 of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: Pole replacements will be constructed using USF standards, PUC standards, and/or specifics approved by a Professional Engineer, which are in line with industry standards.

ii. *Cost-Benefit Analysis*: Each pole replacement is reviewed on a case-by-case basis to identify any available alternatives. Some alternatives may include coordination of replacement programs and/or the replacement of multiple poles with fewer to save costs, additional coordination with adjacent pole owners, etc. However, there are typically no practical alternatives to pole replacements.

iii. *Historical Investments & Outcomes Observed*: Using age distribution of PUC's poles, previous pole testing data, and historical quantities of deteriorated poles identified in the field, PUC attempts to accurately predict the quantity of poles that will require replacement. Costs vary depending on the quantity of the poles identified and the nature of the poles. Historical costs can be found in section 3 and 5 of part A of this document. Through active pole replacement initiatives, PUC has been able to maintain safe and reliable electricity supply.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. INNOVATION

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

STATIONS RENEWAL – SWITCHGEAR, PROTECTION & CONTROL RENEWALS

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC has 14 substations, which house equipment such as switchgear, protection and control assets. These stations are critical in ensuring PUC can supply safe and reliable electricity to its customers. PUC undertakes regular maintenance and testing of its assets on its stations and as such has identified breakers associated to the switchgear that require replacing. As identified through the asset condition assessment, a number of breakers associated with the switchgear have reached end of life and are at greater risk of failure. Historically, PUC has experienced failures of these breakers and have had to borrow un-used tie-breakers from other stations to keep the overall system running. This is no longer a sustainable solution for PUC and is putting greater strain on the network. PUC is proposing to replace two breakers per year for the forecast period with new vacuum style breakers that meet the latest standards and industry accepted technology type. For the test year, 2023, the two replacement breakers will be installed at Substation 1. For the years 2024-2027, two breakers per year will be replaced at other stations which are selected prior to each year. The prioritization of the stations is based on current test results and consideration to the customer exposure that would arise due to a breaker failure (e.g., a feeder with a high customer count, mains vs. tie breaker or feeder).

2. Timing

i. Start Date: 2023

ii. In-Service Date: 2023 - 2027

iii. Key factors that may affect timing: There are currently no known factors that could affect the timing. PUC will continue to monitor supply chain and resource constraints and adjust as required.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	67	37	244	400	1,326	176	178	181	191	178
Contributions	(5)	0	(22)	(39)	0	0	0	0	0	0
Capital (Net)	62	37	222	361	1,326	176	178	181	191	178

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PUC has periodically replaced failed breakers in the past. In 2022, PUC is replacing a failed breaker at Substation 19, with an estimated quote for the breaker of $65K. PUC has used this quote, and included factors such as inflation, install and material costs to forecast its costs for 2023-2027.

6. Investment Priority

This is a high priority investment. If these breakers are not replaced then there is a greater risk of failure. Should a failure occur this could have a significant impact on PUC ability to deliver safe and reliable electricity supply. Using PUC's prioritization process, the project is ranked 6th out of 11. In the prioritization process, Public Safety Impact and Customer Value for Dollars Spent were the primary reasons for the relatively high ranking of this project.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Do Nothing** – This is not an option, as if the breaker fails then PUC ability to supply safe and reliable electricity is severely impacted and in some cases significant outages could be experienced by multiple customers.
- **Option 2: Like for Like Replacement** – This is the preferred option. PUC will replace breakers at risk of failure and at end of life with a new vacuum stye breaker that meets the latest standards.
- **Option 3: Borrow breakers from other stations** – While PUC has employed this tactic occasionally in the past, this is not a sustainable solution. This requires there to be an ability to borrow un-used tie-breakers from other stations. However, this can put strain on the network overall as these stations would no longer have the full protection in place. In addition, the typical type of breaker now used by utilities is a new vacuum style breaker.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This project does not fall in the category requiring leave to construct.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	New breakers installed will meet the latest technology and standards, which inherently makes them more efficient than the older assets. PUC is planning on installing new vacuum style breakers. PUC plans on purchasing the same breakers as they have in the past, which standardizes equipment bringing efficiencies to maintenance and operating tasks.
Customer Value	By upgrading and renewing station assets, PUC will ensure that customer have access to safe and reliable electricity.
Reliability	This investment will upgrade older and poor condition assets that are at risk of failure, with newer assets that which will ensure PUC continue to maintain system reliability.
Safety	By upgrading and renewing older station assets, PUC mitigates hazards from any unexpected failures to increase worker safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Failure Risk* – This investment includes asset renewal projects of assets that are past end of life, in poor and very poor condition and at risk of failure. This will help maintain an efficient and reliable electricity system by reducing the risk of asset failure.

ii. Secondary Drivers: *Functional obsolescence* – PUC strives to maintain an efficient system, so identifying and replacing inefficient or obsolete technology helps PUC achieve operational efficiency.

iii. Information Used to Justify the Investment: This investment is informed by PUC's Asset Condition Assessment and Asset Management Plan, which helps identify end-of-life assets or assets in poor and very poor condition. From the asset condition assessment, 7 switchgear assets were identified as being in poor and very poor condition, with a further 3 in fair condition (in need of consideration for replacement). This data has been used to help inform it asset management plan and the forecast replacements. More details on PUC's asset management plan and asset condition assessment could be found in Section 5.3 and Appendix H of the DSP.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: The protection and controls meeting interoperability standards will be specified and implemented for this investment. Switchgears used will conform to ESA, CSA, and IEEE standards. PUC is proposing that the new breakers are the new vacuum style breaker which is the latest technology type that utilities use.

ii. *Cost-Benefit Analysis:* Where alternatives have been considered and the ranking of a proposed project relative to alternatives has been affected by the imputed value of benefits and costs, these benefits and costs should be described and explained in relation to the proposed project and alternatives. If PUC was to employ the 'Do Nothing' option, it would have to replace any failed breaker reactively, which inherently puts premium on costs compared to pro-active costs. In addition, there are the potential knock on effects of the outages etc.

   Option 3 may seem to be a beneficial option as other breakers are moved from station that's don't require them at the time. However, it is time consuming to keep moving breakers around to the stations that require them. This is a short term solution and is employed in a reactive setting, where there has been an unexpected failure.
   Option 2 allows PUC to be pro-active and plan out its replacement, procuring the breakers through normal timelines rather than in a rush substation (which would typically mean costs are increased. In addition, staff and resources are used during normal operating hours, whereas in a reactive situation, staff could be working out of hours which incurs additional costs.

iii. *Historical Investments & Outcomes Observed:* The historical costs of breakers associated with the switchgear replaced during the historical period are detailed in sections 3 and 5 in part A of this document. PUC has observed that where it has replaced failed breakers it has been able to maintain its ability to deliver safe and reliable electricity supply to its customers.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this investment.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

UG RENEWAL – VAULTS

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC's underground distribution system employs concrete chambers for various functions. Manholes provide the junction point on underground ducts to facilitate cable pulling and provide access for inspection of cable splices. Vaults provide below grade space of installation of electrical equipment such as submersible transformers or switches. In the case manholes, steel reinforced concrete is used for walls, roofs and floors. Recent constructure of vaults includes reinforced concrete for the walls and floors (where installed), with steel frames and lids installed. Many historical installations of a vault included less secure walls and relied on the stability of the ground itself. In locations subject to flooding floor drains and sump pumps are provided. Vaults where heat generating equipment such as distribution transformers are installed are also equipped with ventilation grates. Man access is provided through the top. When vaults and manholes are located in roadways, parking lots or other areas open to vehicular traffic, the structures must be designed by a structural engineer. Since manholes and vaults are confined spaces, they must be adequately sized to rescue trapped workers during a fire or explosion inside the vault or manhole. As of June 2022, PUC has approximately 1,440 vaults, including manholes, vaults for pad mounted switches, junction units, minipad transformers and submersible transformers.

The common degradation mode for manholes and vaults is the deterioration of concrete structures due to concrete spalling and corrosion of rebar, sinking of the roof top surfaces allowing rainwater to collect and flood the manhole and vaults. Functional obsolescence, where the size of the manhole or vault no longer meets the space requirements, can also lead to end of life of a structure. The continued reliability and safety of the underground distribution system is reliant on the performance and condition of equipment installed in vaults throughout PUC's service territory.

The health and condition of manholes and vaults can be measured through visual inspection looking for structural damage to concrete walls or roof, frequent flooding incidents, non-functioning drains or sump pumps, or inadequate space. A few examples are shown in the following figures.

Figure 1: Pictures Showing the Condition of Underground Vaults on PUC's System.

The majority of PUC's underground electrical system built in the downtown area is beyond its useful life. Physical inspections within PUC's inspection process identify vaults that require repair and/or rejuvenation. PUC is proposing to address short term vault concerns over the forecast period with the following work:

- **Rejuvenation of major vaults identified as deficient:** PUC is proposing to proactively rejuvenate one major vault per year over the forecast period, for a total of 5 major vault rejuvenations. A major vault in this category generally includes a major pullbox or splice vault and excludes manhole replacements. As vaults are identified through annual inspections, they are added to the list to address. The rejuvenation efforts associated with these major vaults vary from a replacement of steel beams and rebuild of concrete to a complete vault replacement. Structural engineering is required to assess on a vault by vault basis to determine the rejuvenation scope of works.
- **Rejuvenation of minor vaults identified as deficient:** PUC is proposing to proactively rejuvenate 2 minor vaults per year over the forecast period, for a total of 10 minor vault rejuvenations. Minor vaults generally include residential splice vaults, submersible transformer

vaults and pad mounted junction unit vaults. Typically, the rejuvenation efforts associated with these minor vaults include a complete replacement. Many submersible transformer vaults that require replacement are replaced with vaults for minipad transformer installation to improve safety and system reliability.

- **Manhole 123:** Through recent inspections, Manhole 123 has been determined to be a safety hazard to traffic passing over the manhole. The manhole lid has been repaired and secured down to the manhole temporarily to minimize risks. However, there is a reliability concern as significant effort will be required to access the manhole. PUC is proposing to complete a full assessment of Manhole which will include an engineering assessment, and recommendation to rejuvenate the manhole. Upon receipt of the assessment, PUC will determine the best course of action which may include rejuvenation, replacement or reworking the electrical system to eliminate the manhole.

By proactively addressing these structurally deficient vaults and manholes, PUC will be able to prolong the useful life of these structures and protection of the assets within these structures, and also mitigate risks to public safety, employee safety and system reliability while maintaining the long-term viability of the distribution system.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Key factors that may affect timing include material and resource constraints.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	79	68	61	5	0	401	89	91	95	89
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	79	68	61	5	0	401	89	91	95	89

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

The costs per vault rejuvenation significantly vary from vault to vault depending on the nature of the repair, especially with major vaults. Replacement of a manhole can be in excess of $250,000 if the deterioration warrants a rebuild. Minor vaults are slightly different and typically result in a $15,000 to $25,000 rebuild.

6. Investment Priority

This is a moderate priority investment, therefore emergency plans and system access projects take precedence over program. Using PUC's prioritization process, this project ranks as 7th out of 11. In the prioritization process, Public Safety is the main contribution to the ranking of this project. Due to the nature of the hazard, it is important to rejuvenate the vaults, removing safety hazards and increasing system reliability.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Do Nothing** – Although it is possible to barricade off the areas around some of the vaults, it is not a practical solution to defer the vault rejuvenation with the increased safety risk to the public.
- **Option 2: Repair Deteriorated Vaults** – Each vault is reviewed on a case by case basis to determine the extent of the deterioration. If a simple repair will safely return the vault to a fair condition extending the vault's useful life, this is completed. In many instances, repair jobs only defer the requirement for rejuvenation and therefore is reviewed in detail prior to proceeding.
- **Option 3: Rejuvenate Deteriorated Vaults** – In cases where the deterioration of the vault has been identified as severe, creating a potential safety hazard, and the deterioration is generally beyond a simple repair, a detailed review from a structural engineer is completed to determine the best solution.

8. Innovative Nature of the Project

There is nothing innovative in this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Planned rejuvenation efforts can be carried out by resources during regular business hours, thus avoiding overtime premiums associated with unplanned efforts potentially occurring after-hours. The proactive rejuvenation of these structures will also ensure continued effective operation of PUC's underground distribution system.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	Customers will benefit via maintained system reliability and reduced risk of vault / manhole failures thereby reducing the potential health and safety risk to customers.
Reliability	The proactive rejuvenation of the structurally deficient vaults and manholes will maintain the reliability performance of the system by reducing the risk of a failure posed by the vaults and manholes.
Safety	By proactively addressing these structurally deficient vaults and manholes, PUC will mitigate risks to public and employee safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Failure Risk* – The identified vaults and manholes requiring rejuvenation have been identified as deficient and are therefore more prone to failure. A failure of a vault or manhole could pose significant safety hazards to workers and the public, while also impacting the reliability and effective operation of the system. This program is required to reduce the failure risk associated with these structures.

ii. Secondary Drivers: *Safety Risk* - This program is needed to rejuvenate those assets such that PUC staff are able to safely enter the vaults to perform work to reduce the outage duration.

iii. Information Used to Justify the Investment: Manholes and vaults are inspected at a minimum frequency of every three years. During these inspections, when a vault demonstrates deterioration to the extent that structural integrity is questioned, the vault is identified as "follow-up required". A more detailed review and inspection from experts occur to determine the most practical course of action. Additional information on PUC's asset management process and maintenance and inspection practices can be found in Sections 5.3.1 and 5.3.3 of the DSP, respectively.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: By proactively addressing deficient vaults and manholes prior to failure, PUC will reduce the cost since work can be performed during regular business hours avoiding overtime premiums that would be incurred if the vaults had to be addressed reactively. In addition, this work will be completed in accordance with PUC's standards and the ON Reg. 22/04 to ensure no undue safety hazard.

ii. *Cost-Benefit Analysis:* Vaults and manholes are an integral part of the underground system, and investments in them are required in order to maintain a safe and reliable system. Doing nothing and running the structures to failure would be more hazardous, costly and impactful relative to proactive rejuvenations as it could impact safety and/or decrease the reliability and operational effectiveness of the system.

iii. *Historical Investments & Outcomes Observed:* PUC has historically not experienced deterioration of many major vaults. Minor vault replacements occur on an annual basis, through inspection, as they are identified as deficient. It is evident that replacement of submersible vaults with vaults to accommodate minipad transformers outside of pedestrian and vehicular traffic areas has reduced safety concerns and maintained system reliability and switching efficiencies.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

STATIONS RENEWAL – BUILDING & FENCE REPAIRS

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

Across PUC's fleet of substations, there are many buildings that house the critical infrastructure that is used to operate the station and the system. In addition, each station has fencing around it to restrict access to authorised staff only and to provide safety protection to the general public and to prevent theft and vandalism. PUC has a Station Renewal - Building & Fence Repairs program to ensure the upkeep of the buildings and the associated fences. Projects are typically split into three categories:

- Contingency Repairs – This category addresses any repairs and upgrades to the fencing around the stations, associated grounding and bonding, gates, as well as any unexpected building repairs that are required.
- Station Upkeep and Aesthetics – This addresses items such as rust removal and treatment, painting and general upkeep to ensure the structures and station equipment remain in good condition and to prevent deterioration. Eliminating any potential safety hazards is also a driver.
- Building Structures and associated assets – Any physical building structure upgrades and repairs are covered under this category. For example, replacement or repair of metal clad enclosures or brick buildings.

PUC has designed an annual program, identifying projects across these three categories.

2. Timing

i. Start Date: 2023

ii. In-Service Date: 2023-2027

iii. Key factors that may affect timing: Timing of these upkeep projects is generally not critical other than safety items identified through stations inspections which are addressed promptly when identified. Materials are generally relatively available and have short lead times so no issues with completing this work in a timely fashion is currently anticipated.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	74	1	2	43	86	144	115	97	102	96
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	74	1	2	43	86	144	115	97	102	96

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Due to the nature of the projects within this program, and the fact that they are relatively variable and different, there are no good cost comparators available.

6. Investment Priority

This is a low priority investment, ranked 8th out of 11 material projects in the test year. Other than the handful of grounding repairs and breached station fence repairs anticipated, the balance of other repairs does not constitute an immediate material safety risk. However, if left unaddressed for too long, they are expected to lead to a decrease in service levels through reliability reductions and lead to the need for much more costly remedial solutions in the long term. (e.g., the need to replace an entire switchgear cubicle or overhead structure due to advanced rust rather than sanding and painting minor rusting areas proactively).

7. Alternatives Analysis

Alternatives considered for these projects are case by case as they arise. Generally, in each case, other than the repair approach, 'run to fail' and 'replace with new' are weighed against one another using criteria identified in our prioritizing methodology (i.e., safety impact, outage impact, customer value, system service and project inter-dependability).

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Upgrading assets that to meet the Electrical Safety Authority (ESA) standards assists in maintaining operationally efficient workplace.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	Fences repair is important to maintain public safety, so customers are ensured of a secure and safe electricity facility in their community. In addition, repairs to buildings that house critical operational assets will ensure they are protected from the elements and continue to function as required, ensuring a safe and reliable supply of electricity.
Reliability	This investment does not directly affect the reliability of the electrical system. However, indirectly through these investments the assets are protected from external interference and therefore ensures that PUC can continue to deliver safe and reliable supply.
Safety	Building and fence repairs are required to maintain public and worker safety.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Safety* – Fences and building repairs help mitigate public and worker safety hazards by maintaining a secure facility.

ii. Secondary Drivers: There are no secondary drivers for this investment.

iii. Information Used to Justify the Investment: This is a need-based investment that has been budgeted based on historical expenditures. It is essential in securing the substations and ensuring public and worker safety.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: ESA and Ontario Building Code standards followed on exhaust fans and climate control when replacing/ upgrading.

ii. *Cost-Benefit Analysis*: Alternatives considered for these projects are case by case as they arise. Generally in each case, other than the repair approach, 'run to fail' and 'replace with new' are weighed against one another using criteria identified in our prioritizing methodology (i.e., safety impact, outage impact, customer value, system service and project inter-dependability).

iii. *Historical Investments & Outcomes Observed:* Due to the facility being relatively new, PUC has no experience with similar historical costs that can be used for comparison.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing inherently innovative to PUC about this project.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

BUILDINGS

INVESTMENT CATEGORY:

GENERAL PLANT

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC has a large operations and administration facility, built in 2012, that represents the critical backbone of PUC's 24/7 operations, as it houses the office and field staff who undertake the daily operations, including customer billing, engineering & planning, field services as well as operations within the control room. Without investing in this facility, there will a be detrimental impact on PUC operations that could affect both the safety of staff, as well as have an indirect impact on the reliability of the system and the ability to deliver services cost effectively.

As the facility is reaching 10 years in service, PUC has undertaken an extensive review of the facility to identify the most critical projects that are required to be carried out to ensure the safe and reliable continuation of PUC's operations. The following list highlights the proposed work and costs to be carried out in the 2023 Test Year:

Table 1: Proposed Building Work & Costs in 2023

Projects	2023
CO/NOx Detecting System (fleet garage) - Replacement	$100,368
BMS (Building Management System) - Software & Hardware – Replacement	$62,730
Rotary Lift - Fleet Mechanic Shop – Upgrade of Obsolete parts	$18,819
Power Washer - Operations Wash Bay – Replacement of end of life system	$25,092
Misc. Items	$31,365
Total	**$238,374**

2. Timing

i. Start Date: Jan 2023

ii. In-Service Date: Dec 2023-2027

iii. Key factors that may affect timing: If new projects of higher priority in other categories are developed then this may mean PUC will have to adjust its plan for lower priority projects (i.e., System Access (non-discretionary) projects take precedent and resources, and budget may be reassigned).

3. Historical and Forecast Capital Expenditures

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	8	178	110	589	36	238	293	265	361	592
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	8	178	110	589	36	238	293	265	361	592

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Building program investments are ongoing expenditures primarily associated with the upkeep of PUC's main facility located at 500 Second Line in Sault Ste. Marie, which was constructed in 2012. The facility entails the office tower for all administrative staff, operations headquarters, the fleet garage, fueling facilities, stores building and stores yard, and a handful of smaller outbuildings. In the previous 5 historical years, PUC has spent approximately $885,000 maintaining and undertaking minor repair projects to ensure the continued safe, efficient and reliable operations. Of that amount, approximately $700,000 went towards an unplanned project to replace all of the original motor operated roll-up doors in the fleet garage in response to a health and safety near-miss deficiency in which the doors could fall abruptly without notice. The historical costs are identified in section 3 of this document.

Typically each building project is different, and therefore a comparison of historical projects and future projects is not indicative of a particular trend. Over the past year, PUC has begun a formal asset management program specific to facilities which is expected to improve information and planning with respect to this area of general plant moving forward. Currently, PUC engages with contractors and suppliers in developing and understanding associated costs. In addition, factors such as inflation and supply chain and material costs are used to generate the forecast costs.

6. Investment Priority

These investments have been assigned a relatively low priority, ranked as 9th out of the 11 initiatives for the test year. Impacts in the area of safety, customer outages, and customer service levels would be minimal relative to other projects. Any benefits to be derived from this basket of projects are primarily in the area of customer value, where customer dollars are focussed on eliminating inefficiencies that over time would lead to burdensome O&M expenses or costly unplanned capital expenditures to address if deferred for too long.

7. Alternatives Analysis

PUC considered the following options:

- **Option 1: Do Nothing –** This option is not feasible. Many of the assets associated with PUC's facility are reaching their end of life and/or have become obsolete. Without investing in replacing these assets, there is a risk that the facility will not be fit for PUC staff to carry out their jobs safely and efficiently.

- **Option 2: Carry out the proposed pacing of investments –** PUC has identified a list of all minor projects it needs to carry out on its facility. PUC has then determined which are most critical to undertake in the next five years and which can be monitored and pushed out to later years. This has resulted in the proposed project plan that accounts for urgency of investment and the resources and budget available.
- **Option 3: Increase pacing of investments required –** This option would see PUC bring forward projects into earlier years and carry out more work each year. While this may help address certain issues quicker, it also increases the overall budget and could take money and resources away from other critical work in the other investment categories. As a result, PUC does not recommend this option.

8. Innovative Nature of the Project

There is nothing innovative about the investments proposed.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	By investing in its facility to keep it up to date, clean and safe, PUC will indirectly ensure that staff can continue to work in a safe and comfortable environment which will enable the staff to maintain its efficiency.
Customer Value	A safe, warm and clean environment ensures that staff can undertake their work effectively and efficiently by delivering what customers need.
Reliability	Through these investments, there is no direct impact on reliability of the network in terms of planned outages. However, the facility houses equipment and materials that are used on a daily basis to help maintain the reliability of the system, and therefore there is an indirect impact. There is also a direct impact of maintaining and upgrading the facilities as in-field crews can continue to get to their work sites and/or respond to outages in a timely manner.

Primary Criteria for Evaluating Investments	Investment Alignment
Safety	The replacement of obsolete and/or end of life assets within the facility, such as the CO/NOx detection system, ensures that PUC has functioning assets that meet the latest health and safety standards and regulations keeping its staff safe while carrying out their work activities.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *Non-System Physical Plant* - The primary driver for this program is to renew and invest in PUC's non-system physical plant. Within the context of this program, it is to invest in PUC's facilities that house in-office & operations staff and equipment that is used for maintenance and operations.

ii. Secondary Drivers: *System Maintenance Support* - The facility houses maintenance equipment and vehicles and contains the workshops for the field staff to undertake repairs. By investing in the facility and ensuring it is fit for purpose, PUC is protecting the equipment stored which helps to ensure that they will work when needed.

iii. Information Used to Justify the Investment*:* The following information has been used to determine the proposed projects:

- CO/NOx detection system – The CO/NOx system is an essential life safety system that monitors air quality in the fleet garages and workshops. These are subject to annual inspections. This system has reached its expected end of life (10 years) and to comply with safety rules it requires replacing.
- BMS (Building Management System) - Software & Hardware – This system is the computerized software system that allows facilities to keep an eye on building systems in the main office building including, heating, cooling, ventilation, life safety and access systems. The software will have reached its end of life in 2023 and will no longer be supported by the vendor and will be deemed to be obsolete. Controllers for air handling units, chillers and boilers are no longer compatible with the software and alarms can no longer be cleared due to some hardware failures and software incompatibility. Furthermore, replacement hardware components will also be more difficult or impossible to source as time goes on. As this system is critical to PUC operations, as it keeps buildings running safely and efficiently, it is imperative that it is upgraded to the latest version to ensure it is fully supported by the OEM.
- Rotary Lift – Fleet Mechanic Shop – The electronics and control board for the remote pendant of the Rotary lift no longer function correctly. The original unit has also been identified as obsolete and is no longer supported by the manufacturer. Therefore, an upgrade kit is required to ensure the continued reliable operation of the lift.

- Power Washer - Operations Wash Bay – The power washer is used to keep the PUC fleet clean and maintained in good working order. The unit has been rebuilt several times and it has become cost prohibitive to rebuild further. A replacement unit is now proposed.
- Misc. Items – There is a set of minor projects required which are typically based on the end of useful life of the assets. Currently identified for replacement are controller units for two motor variable frequency drives (VFD) in the building chillers and refractor replacements for heating and hot water system boilers.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: To ensure that PUC can deliver safe, reliable and efficient service, it is fundamental that PUC has the necessary foundations in place. For any utility it is accepted practice that an office space is required to house staff from engineering to accounting so customer needs can be met. In addition, it is important that field staff have the resources, tools, equipment and space to carry out maintenance and capital projects. It is good practice for utilities to incur costs each year to maintain its back office, field staff shops and storage areas. PUC has carefully reviewed and planned what is required to be carried out to ensure it can still operate and delivery safe, reliable and efficient service to its customers.

ii. *Cost-Benefit Analysis:* On a case-by-case basis for each of the initiatives in this basket of projects, PUC carefully reviews the impacts of doing nothing, completing partial repairs, looking for new solutions or technologies, or employing like for like replacements. This usually entails research of solutions with vendors, reviewing available products online, or consulting with contractors and consultants with expertise in the particular project area. The solution that presents the best long-term value is then selected.

iii. *Historical Investments & Outcomes Observed:* Historical costs are indicated in section 3 of part A of this document. Historical investments have resulted in the ability for PUC staff to continue to perform all its critical services, as well as investing in the upkeep of the building, addressing health and safety defects that were identified. This has ensured the continued ability to operate 24/7 and deliver safe and reliable electricity supply to its customers.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. INNOVATION

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing innovative about the investments proposed.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

TOOLS & EQUIPMENT

INVESTMENT CATEGORY:

GENERAL PLANT

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

PUC plan to continue investing in its tools and equipment used to carryout and improve its testing and inspection regimes. This will allow the utility to make informed decisions on replacing and/or repairing key assets. The Tools/Equipment program is designed to equip PUC with tools, monitoring and testing products that will enable the utility to make more informed asset investment decisions such that the utility can continue to provide safe, reliable, and effective services to its customers. The results and data collected from using these tools and equipment will further help enhance PUC's asset condition assessment and help address some of the data gaps identified in the ACA report.

The following tools/equipment will be purchased across the 2023-2025 period. No investments are currently planned for 2026 and 2027. However, PUC will continue to assess this throughout the period and may any adjustments to its budgets as required.

Table 1: Proposed Tools/Equipment for Purchase

Tools/Equipment	Year of replacement	Description of Function
Omicron Injection Tester	2023	This test equipment is essential to allow testing of protection and control systems, ensuring all system relays and breakers operate correctly. This will ensure downed lines and failed equipment do not lead to public or worker safety hazards and that system reliability remains at acceptable levels
Transformer Oil Drying Equipment	2023	This equipment will allow staff to deal promptly, and cost effectively deal with issues of moisture in stations and padmount transformers in-house.
IR Camera	2024	This infrared camera combined with an inspection program is important to identify poor electrical connections and weak spots in the electrical distribution system. With this equipment and program, staff can easily identify and sort simple O&M activities like tightening a connector nut from prominent failures that might require a larger capital investment. An IR scanning program is a cornerstone of a well-managed ACA program.
Transformer Test Equipment	2025	With transformers being one of an LDC's highest investments, investing proactively in test equipment such as this will ensure downtimes are minimized and expenditure is spent prudently. It also will provide enhanced data that could allow PUC to identify a problem before a failure occurs.

Tools/Equipment	Year of replacement	Description of Function
ARCO 400 Recloser Tester	2025	With a number of reclosers currently deployed on the distribution system, and more being added as part of the Sault Smart Grid project currently, this tester will be essential to maintaining reliability and service levels.

2. Timing

i. Start Date: Jan 2023

ii. In-Service Date: 2023-2025

iii. Key factors that may affect timing: The only factor that could affect the timing of the project are supply chain issues. However, PUC does not expect any delays of the delivery of the testing equipment.

3. Historical and Forecast Capital Expenditures

Table 2: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	0	0	0	0	0	295	68	61	0	0
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	295	68	61	0	0

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PUC periodically purchases or renews various tools and equipment that are used through its testing and inspection programs. In general, PUC purchases its tools through two methods depending upon the application of the tool. For tools that are exclusively for use in the electrical distribution system, PUC buys tools directly, with larger tools being recorded as a one-time capital expenditure. The tools proposed for 2023-2027 in this narrative all fall into that category. For more generic tools that have applications inside and outside of the electrical distribution system, PUC's affiliate company PUC Services Inc. purchases and owns the tools. They are then charged out to the various PUC affiliate companies in proportion to the amount that they are used by each affiliate. For the historical period 2018-2022 there were no tools purchased directly by PUC Distribution Inc. so no historical information is available for comparative purposes.

6. Investment Priority

This is a lower priority investment that was scored 10th out of 11. The equipment proposed to be purchased is critical in PUC being able to carry out their testing programs and gather further data to enable PUC to continue to determine the condition of assets and develop an informed ACA process. This data is then used as an input to help inform the investment plan. Although a deferral of investment now may not have immediate financial or reliability consequences, over time these would be expected to grow.

7. Alternatives Analysis

The following options have been considered:

- **Option 1 – Do Nothing**: Doing nothing is not a viable option for PUC. This would mean that PUC would be unable to carry out the necessary testing and inspections required to help inform the condition of their assets. It would also make it harder for PUC to put together a robust, data driven investment plan. Furthermore, it would put assets at risk of failure and expose customers to longer and more frequent outages in the event of preventable failures.
- **Option 2 – Invest in inspection and testing tools and equipment**: This option sees PUC invest in tools and equipment that allows the field staff to carry out testing and inspections on certain assets, gathering data that is used to inform both capital and maintenance plans. The data can be used to update the asset condition assessment of PUC's assets and inform investment plans. It is common practice amongst utilities to have different testing tools and equipment to help better manage and maintain the electricity network.

8. Innovative Nature of the Project

There is nothing innovative in any of the tools/equipment that PUC is proposing to purchase.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 3: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	PUC will be able to integrate the resulting data into their decision-making analytics such as ACA in order to identify and prioritize investment work that is required. In addition, by enhancing their testing methodologies with tools such as an IR camera, this will allow PUC's field technicians to be more targeted in the maintenance they undertake and be able to address issues efficiently and proactively before they materialise, reducing the likelihood of an outage.

Primary Criteria for Evaluating Investments	Investment Alignment
Customer Value	PUC's approach to determining investment is grounded in a data-driven approach. By investing in various tools and equipment, it enables PUC to gather more data on its assets, improve its testing and inspection process. This enables PUC to address the most critical areas on its distribution system.
Reliability	Through continued investment in tools and equipment that allows PUC to carry out its testing and inspection regime, it enables PUC to better assess the condition of its assets. This allows PUC to proactively address the most critical assets, ensuring that the reliability of the system is maintained.
Safety	The results of any inspection and testing help inform which assets need investment, including in need of immediate investment due to safety concerns.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver: *System Maintenance Support* - The primary driver for this program is to improve its system maintenance support. PUC undertakes regular inspection and testing of its assets. PUC is always looking to make improvements to these processes, both in terms of improving what can be tested and the quality of data. The continued investment in various tools and equipment will enhance PUC's testing capabilities, helping to improve and enhance the development of its investment plans.

ii. Secondary Drivers: There are no secondary drivers for this program.

iii. Information Used to Justify the Investment: Budgeting for these items is based on informal quotes from vendors. Prior to purchase, PUC goes through its formal procurement processes. This involves seeking multiple quotations through an RFP process. These quotes are reviewed prior to purchase of the tools and equipment to ensure that the best value is obtained.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: It is accepted industry practice that utilities should build a data driven investment plan. As part of this, utilities carry out inspections and testing to gather asset condition data. To enable this, various tools and equipment are required, depending on the type of asset. Through investment in the proposed tools and equipment over the forecast period, PUC will be able to improve its knowledge of the condition of its assets which in turn will help refine and inform its investment plans.

ii. *Cost-Benefit Analysis:* On a case by case basis, PUC carefully weighs the pros and cons of purchasing tools to determine the best value approach. For example, test equipment versus contracting out testing services.

iii. *Historical Investments & Outcomes Observed*: Historical costs are indicated in sections 3 and 5 or part A of this document. Through these historical investments in tools and equipment, PUC has been able to successfully gather data that has informed asset condition and been used in its investment decision making process. In addition, these investments have helped PUC's field-staff to better prioritize and carry-out key maintenance activities.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

There is nothing innovative in any of the tools/equipment that PUC is proposing to purchase.

MATERIAL INVESTMENT NARRATIVE

PROJECT / PROGRAM:

OH RENEWAL – GENERAL ASSET

INVESTMENT CATEGORY:

SYSTEM RENEWAL

A. General Information on the Project/Program

A distributor is expected to provide information about the investment, which includes the need, scope, key project timings (including key factors that affect timing); total expenditures (including capital contributions and the economic evaluation as per section 3.2 of the Distribution System Code, as applicable); comparative historical expenditures; investment priority; alternatives considered; and the cost-to-benefit analysis of the recommended alternative. A description of the innovative nature of the investment, if applicable, should be included.

1. Overview

The general asset renewal tasks included under this program represent small projects over the forecast period that are not considered emergency repairs, do fit within the existing program categories and do not warrant additional program categories. This includes:

- **Removal, cleanup and disposal of pole butts:** As a result of resource constraints and other logistical challenges, it is not always possible to remove poles at the time of the pole replacement. The primary factor for this is the joint use attachments and the legal requirement to permit companies to transfer to the new pole. As a result, there are several poles remaining within PUC's distribution system that need to be addressed. As of July 19, 2021, PUC's database indicates that there are currently 420 outstanding poles to be removed across the service territory, with more anticipated to be identified over the forecast period. On average, PUC has historically pulled 142 poles per year that cannot be removed at the time of replacement. Safe removals require vacuum truck excavations, and the cost of pole disposal has significantly increased recently due to new regulatory requirements, which strictly monitors disposals, especially that of creosote-soaked poles. Over the forecast period, PUC is proposing to remove approximately 150 poles per year that cannot be removed at the time of replacement, clean up an additional 100 poles per year, and dispose of all poles in an environmentally acceptable manner.
- **General Overhead Tasks**: General overhead tasks include minor infrastructure renewal tasks that arise from maintenance programs, field inspections and/or information provided from third parties and can include the replacement of minor assets in poor condition, addressing voltage concerns, and/or planning for future projects.

The bulk of the costs included under this program are associated with the removal, cleanup and disposal of distribution poles.

2. Timing

i. Start Date: January 2023

ii. In-Service Date: December 2027

iii. Key factors that may affect timing: Key factors that may affect timing include resource constraints, response time from communication companies and weather restrictions.

3. Historical and Forecast Capital Expenditures

Table 1: Historical & Forecast Capital Expenditures

	Historical Costs ($ '000)					Forecast Costs ($ '000)				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Capital (Gross)	81	68	74	46	184	172	175	178	188	175
Contributions	0	0	0	0	0	0	0	0	0	0
Capital (Net)	81	68	74	46	184	172	175	178	188	175

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Removal of poles after all joint use attachments is the primary cost to this program. Expenditures can fluctuate year to year based on many different factors, including, but not limited to areas of construction, response times of communication companies, resource availability and weather restrictions. The costs to this program are immediately affected by PUC's available resources typically inverse of system access requirements.

6. Investment Priority

This is a low priority investment, therefore emergency plans and system access take precedence over this program. Using PUC's prioritization process, this project ranks 11th out of 11 projects. Although the safety risks of the pole after the wires and related infrastructure have been minimized, completion of the project immediately impacts PUC's image in the community. It is important to complete projects and restore the network to pre-existing conditions.

7. Alternatives Analysis

PUC has considered the following options:

- **Option 1: Complete Communication Transfers –** PUC has reviewed opportunities to complete transfers of joint use attachments at the same time as the pole replacement. After discussions with Joint Use parties, this is not a preferred option as safety and costs would increase.
- **Option 2: Complete Pole Removals After Transfers –** Completing the pole removals after the joint use transfers are completed allows for planned transfers and pole removals increasing safety and optimizing costs.

8. Innovative Nature of the Project

There is nothing inherently innovative to PUC about this project.

10. Leave to Construct Approval

Where an investment within the five-year forecast period involves a Leave to Construct approval under Section 92 of the OEB Act, the applicant must provide a summary of the evidence, to the extent that it is available, for that investment consistent with the requirements set out in Chapter 4 of these Filing Requirements (sections 4.3 and 4.4 in particular).

This is not applicable.

B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

The OEB evaluates material investments based on the outcomes set out in section 5.0.2. Efficiency, customer value, reliability, and safety are the primary criteria for evaluating any material investment.

Table 2: Investment Evaluation - Efficiency, Customer Value, Reliability & Safety

.Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The effect on system operation efficiency and cost-effectiveness may vary from project to project; however the nature of the work included within this program will typically have no effect on this in most cases.
Customer Value	Customer value may vary from project to project, however the work included within this program will ensure the elimination of potential safety hazards (e.g., pole butts). Some of the general overhead tasks could also help mitigate potential safety risks and maintain system reliability.
Reliability	The impact on reliability may vary from project to project, however some of the general overhead tasks could also help maintain system reliability.
Safety	The impact on safety may vary from project to project, however the work included within this program will ensure the elimination of potential safety hazards (e.g., pole butts). Some of the general overhead tasks could also help mitigate potential safety risks.

2. Investment Need

A distributor should demonstrate the need for the investment, which generally should be related to a distributor's asset management process. There could also be instances where the need is to address safety, cyber security, grid innovation, environmental, statutory obligations, or regulatory obligations. A distributor should provide adequate support in justifying the need for investments that are not outcomes of the asset management process.

i. Main Driver*: Functional obsolescence* – Once poles are replaced, the pole butts have no functional use and therefore should be removed, cleaned up, and safely disposed of.

ii. Secondary Drivers*:*

   a. *Mandated Obligations* – Due to regulatory requirements, disposals of creosote poles require a licensed contractor to dispose of the material ensuring a safe disposal. Through recent experience and regulatory revisions, the risk of utility assets installed in close proximity (and sometimes through) to PUC poles requires daylighting utility assets within 1m of the pole. This typically requires a vacuum truck to daylight the assets and comply with regulations.

b. *Safety & Reliability* – The work required is due to pole replacements in either system access or system renewal. Many of these replacements help mitigate safety risks and maintain reliability. Please refer to system access and subsequent system renewal programs for further detail.

iii. Information Used to Justify the Investment*:* Information used to justify the investment include PUC's database of outstanding poles that need to be removed, cleaned up and safety disposed of. This information is tracked as part of PUC's asset management process. In addition, information that arises from maintenance programs, field inspections and/or information provided from third parties is also used to identify the need for other general overhead tasks required under this program. Additional information on PUC's asset management process and maintenance and inspection practices can be found in Sections 5.3.1 and 5.3.3 of the DSP, respectively.

3. Investment Justification

Justifying an investment can be demonstrated through evidence of accepted utility practices or cost-to-benefit analysis of alternatives. It is also helpful to show past costs for similar Investments and the outcomes the distributor observed to support the requested capital investments. Where a capital investment substantially exceeds the materiality threshold (e.g., CIS, GIS, new office building) the distributor should file a business case documenting the justifications for the expenditure, alternatives considered (including CDM activities, if applicable), benefits for customers (short/long term), and impact on distributor costs (short/long term).

i. *Demonstrating Accepted Utility Practice*: All pole removals, clean ups and disposals will be done in accordance with PUC's standards and practices and will comply with all applicable regulatory requirements.

ii. *Cost-Benefit Analysis*: PUC has assessed the alternative balancing safety, customer impacts and costs. At this time, there are no other practical options to removing the poles after joint use transfers are completed.

iii. *Historical Investments & Outcomes Observed*: The historical costs of pole removals, clean ups and disposals during the historical period are detailed in sections 3 and 5 in part A of this document. Through its program, PUC has been able to successfully implement this work and reduce the backlog of outstanding pole butts scattered across its service territory.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

If a distributor is requesting funding for a CDM activity, additional guidance on evidentiary requirements is provided in the CDM Guidelines.

This is not applicable.

5. Innovation

Consistent with the OEB's objective of facilitating innovation in the electricity sector, innovative projects and programs may receive special consideration. Innovation has a broad meaning: it can relate to the use of a new technology, or new ways in which to use existing technologies. It could also include innovative business practices, including relationships with others to enhance services to customers and share costs.

The distributor should explain how the innovative project is expected to benefit its customers, such as improved reliability; enhanced customer services; CDM; efficient use of electricity; load management; greater efficiency through grid modernization; lower rates (long-term or short-term); enhanced customer choice; or any other benefit consistent with the OEB's mandate and policies. Projects that allow for testing before deploying at scale or provide valuable data and/or learnings are encouraged. Distributors can seek guidance through the OEB's Innovation Sandbox prior to proposing a project.

This is not applicable.

Appendix B

East Lake Superior Region Needs Assessment Report

Hydro One Networks Inc.
483 Bay Street
Toronto, Ontario
M5G 2P5

NEEDS ASSESSMENT REPORT

East Lake Superior Region

Date: June 14th, 2019

Prepared by: East Lake Superior Region Study Team

Disclaimer

This Needs Assessment Report was prepared for the purpose of identifying potential needs in the East Lake Superior Region and to recommend which need may require further assessment and/or regional coordination to develop a preferred plan. The results reported in this Needs Assessment are based on the input and information provided by the Study Team.

The Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") shall not, under any circumstances whatsoever, be liable to each other, to any third party for whom the Needs Assessment Report was prepared ("the Intended Third Parties") or to any other third party reading or receiving the Needs Assessment Report ("the Other Third Parties"). The Authors, Intended Third Parties and Other Third Parties acknowledge and agree that: (a) the Authors make no representations or warranties (express, implied, statutory or otherwise) as to this document or its contents, including, without limitation, the accuracy or completeness of the information therein; (b) the Authors, Intended Third Parties and Other Third Parties and their respective employees, directors and agents (the "Representatives") shall be responsible for their respective use of the document and any conclusions derived from its contents; (c) and the Authors will not be liable for any damages resulting from or in any way related to the reliance on, acceptance or use of the document or its contents by the Authors, Intended Third Parties or Other Third Parties or their respective Representatives.

Executive Summary

REGION	East Lake Superior Region		
LEAD	Hydro One Sault Ste. Marie LP.		
START DATE	April 16th, 2019	**END DATE**	Jun 14th , 2019

1. INTRODUCTION

The first cycle of the Regional Planning process for the East Lake Superior ("ELS") Region was initiated by the former Great Lakes Power Transmission ("GLPT") in October 2014 and completed in December 2014 with the publication of the Needs Assessment ("NA") Report. The NA Report provided a description of needs and recommendations of preferred wires plans to address near- and mid-term needs at the time.

The purpose of the second cycle NA Report is to review the status of needs identified in the previous regional planning cycle and to identify any new needs based on the new load forecast.

2. REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years for each region. The first cycle of Regional Planning for the ELS Region was triggered in October 2014, and this second cycle Regional Planning was triggered in April 2019.

3. SCOPE OF NEEDS ASSESSMENT

The scope of this NA includes:

- Review and reaffirm needs/plans identified in the previous Regional Planning process; and
- Identification and assessment of system capacity, reliability, operation, and aging infrastructure needs.

The Study Team may also identify additional needs during the next phases of the planning process, namely SA, IRRP and RIP, based on updated information available at that time.

4. INPUTS/DATA

The Study Team representatives from LDCs, the IESO, Hydro One Sault Ste. Marie and Hydro One provided input and relevant information for the East Lake Superior Region regarding capacity needs, reliability needs, operational issues, and major assets/facilities approaching end-of-life ("EOL").

5. ASSESSMENT METHODOLOGY

The assessment's primary objective is to identify electrical infrastructure needs and to determine whether further regional coordination or broader studies would be beneficial for addressing these needs.

The scope of the assessment includes reviewing previously identified needs and identifying new needs based on available information including load forecasts, conservation and demand management ("CDM"), distributed generation ("DG") forecasts, reliability concerns, operational issues, and major high voltage equipment identified to be at or near the end of their useful life.

A technical assessment of needs was undertaken based on:

- Planning criteria outlined in IESO-ORTAC (section 2.7.2) for analysis of current and future station capacity and transmission adequacy;
- Planning criteria outlined in IESO-ORTAC (section 7) for system reliability; Analysis of major high voltage equipment reaching the end of its useful life, in conjunction with emerging system needs; and
- Analysis of operational concerns relevant to Regional Planning

6. NEEDS

I. Station & Transmission Supply Capacity

- Based on planning criteria, Third Line TS 230/115kV Autotransformers T1 and T2 are expected to approach their 10-Day Limited Time Rating over the near/mid-term planning horizon.

II. System Reliability & Operation

- Based on forecasted winter gross load, load security criteria can be met over the study period.
- Load restoration at transformer stations listed below requires further review with affected LDC:

  i. Andrew TS
  ii. Batchawana TS
  iii. Goulais TS

III. Aging Infrastructure – Transformer Replacements and Circuit Refurbishments

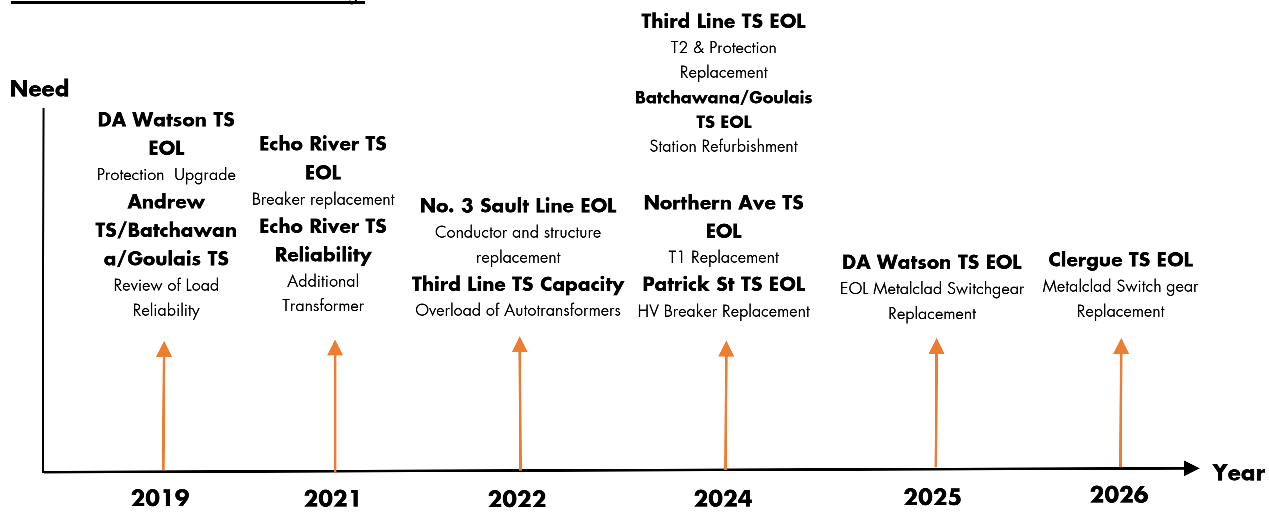
- Projects in execution:

  i. DA Watson TS – Protection Upgrade

- Future projects:

  i. Echo River TS – EOL Breaker Replacement
  ii. No.3 Sault Circuit – EOL Conductor and Structure Replacement
  iii. Third Line TS – Transformer T2 EOL and Protection Replacement
  iv. Patrick St TS – HV Breaker Replacement
  v. Batchawana TS / Goulais Bay TS – Station Refurbishment
  vi. Northern Ave TS – Transformer T1 Replacement
  vii. DA Watson TS – Metalclad Switchgear Replacement
  viii. Clergue TS – Switchgear Replacement

Needs Timeline Summary



7. RECOMMENDATIONS

The Study Team's recommendations for the above identified needs are as follows:

1. Overloading of 230/115 kV Autotransformers at Third Line TS – Further analysis in the Scoping Assessment phase of Regional Planning is required to address supply capacity to the 115 kV systems. IESO will lead the Scoping Assessment phase to determine and to recommend the best planning approach to address the need.

2. Reliability to Load - Load restoration after loss of a single element may lead to longer restoration time than ORTAC guidelines. A review by the transmitter and impacted distributor is required to evaluate the local reliability for the following stations:

   i. Andrew TS
   ii. Batchawana TS
   iii. Goulais TS

3. The implementation and execution for the replacement of the following EOL transmission assets will be coordinated between Hydro One Sault Ste. Marie and the affected LDCs and/or customers, where required. These projects will be coordinated with IESO where required and where feasible within the timelines afforded by each project.

   i. Echo River TS – Breaker Replacement
   ii. No. 3 Sault Conductor and Structure Replacement
   iii. Third Line TS – Autotransformer T2 & Protection Replacement
   iv. Patrick St TS – HV Breaker Replacement
   v. Batchawana TS / Goulais Bay TS – Station Refurbishment
   vi. DA Watson TS – Metalclad Switchgear Replacement

vii. Clergue TS – Switchgear Replacement

4. Overload of No. 1 Algoma circuit due to breaker failure at Patrick St TS and/or other multiple element contingencies requires additional study. Further analysis in the Scoping Assessment phase of Regional Planning is required to determine the best planning approach while taking into account the outcome of an ongoing SIA for new load connection at Patrick St TS.

TABLE OF CONTENTS

List of Tables and Figures

1 INTRODUCTION

This Needs Assessment ("NA") report identifies needs in the East Lake Superior ("ELS") Region. For needs that require coordinated regional planning, the Independent Electricity System Operator ("IESO") will initiate the Scoping Assessment process to determine the appropriate regional planning approach. The approach can either be the IESO-led Integrated Regional Resource Planning ("IRRP") process or the transmitter-led Regional Infrastructure Plan ("RIP"), which focuses on the development of "wires" solutions. It may also be determined that the needs can be addressed more directly through localized planning between the transmitter and the specific distributor(s) or transmission connected customer(s). The development of the Needs Assessment report is in accordance with the regional planning process as set out in the Ontario Energy Board's ("OEB") Transmission System Code ("TSC") and Distribution System Code ("DSC") requirements.

The purpose of the second cycle NA is to review the status of needs identified in the previous Regional Planning cycle and to identify any new needs based on the new load forecast.

This report was prepared by the ELS Region Needs Assessment Study Team listed in Table 1, and led by the lead transmitter in the region, Hydro One Sault Ste. Marie ("HOSSM"). The report captures the results of the assessment based on information provided by the LDCs, Hydro One Network Inc. and the IESO.

Table 1: East Lake Superior Region Study Team Participants

Company
Hydro One Sault Ste. Marie LP. (Lead Transmitter)
Hydro One Networks Inc.
Algoma Power Inc.
Chapleau PUC
Hydro One Distribution
Independent Electricity System Operator ("IESO")
Sault Ste. Marie PUC

2 REGIONAL ISSUE/TRIGGER

In accordance with the Regional Planning process, the regional planning cycle should be triggered at least every five years. The first cycle of Regional Planning for ELS Region was triggered in October 2014, and as such, the second cycle Regional Planning was triggered in April 2019.

3 SCOPE OF NEEDS ASSESSMENT

The scope of this NA covers the entire ELS Region and includes:

- Review of existing needs and/or plans identified in the previous planning cycle; and
- Identification and assessment of any new system capacity, reliability, operation, and aging infrastructure needs.

The Study Team may identify additional needs during the next phases of the regional planning process, namely Scoping Assessment ("SA"), Local Planning ("LP"), IRRP, and/or RIP.

4 REGIONAL DESCRIPTION AND CONNECTION CONFIGURATION

The ELS Region includes all of Hydro One Sault Ste. Marie's (formerly Great Lakes Power Transmission's) 560 km of HV transmission lines as well as ties to the provincial grid at Wawa TS in the Northwest and Mississagi TS in the Northeast. Hydro One Network's 115 kV W2C circuit also supplies the Town of Chapleau from Wawa TS. The boundary of the ELS Region is shown in Figure 1. Figures 2-5 show Single Line Diagram ("SLD") depictions of various parts of the ELS Region.

Figure 1: Geographic Area of the East Lake Superior (ELS) Region

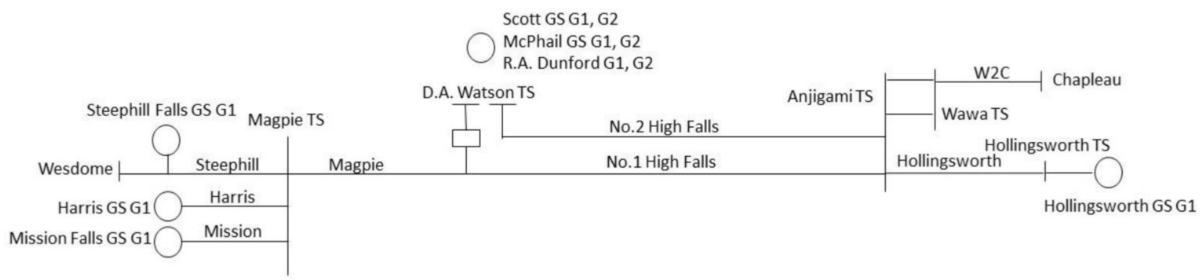


Figure 2: ELS Region – Northern Area Single Line Diagram

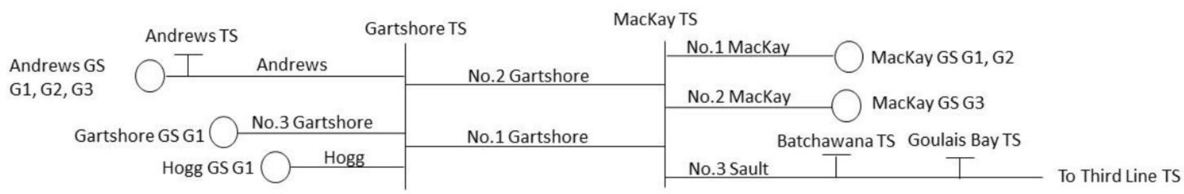


Figure 3: ELS Region – Southern Central Area Single Line Diagram

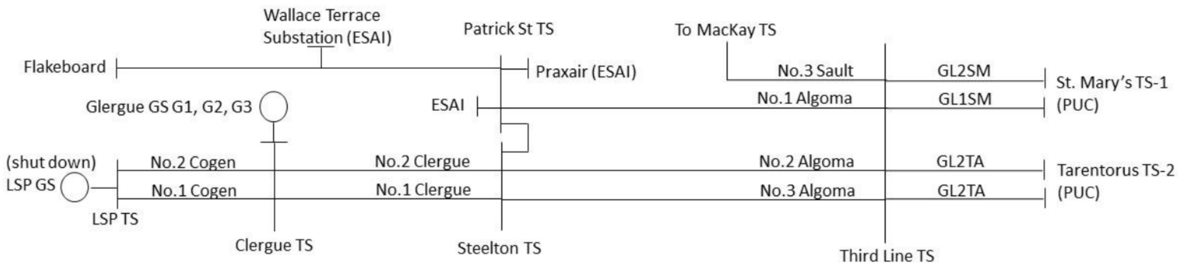


Figure 4: ELS Region – Southern Area Single Line Diagram

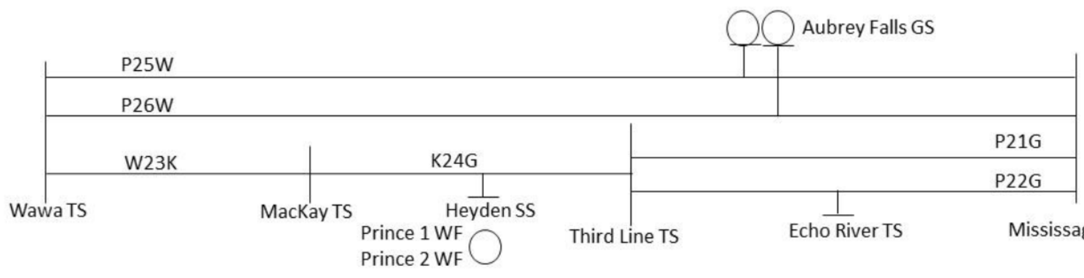


Figure 5: ELS Region – Eastern Area Single Line Diagram

5 INPUTS AND DATA

Study Team participants, including representatives from LDCs, IESO, Hydro One and HOSSM provided information and input for producing the ELS Region NA Report. The information provided includes the following:

- ELS Region Summer and Winter Non-Coincident Load Forecast for all supply stations
- ELS Region Summer and Winter Coincident Load Forecast for all supply stations
- Known capacity and reliability needs, operating issues, and/or major assets approaching the end of their useful life ("EOL"); and
- Planned/foreseen transmission and distribution investments that are in scope for the ELS Region.

6 ASSESSMENT METHODOLOGY

The following methodology and assumptions are made in this Needs Assessment:

- Load forecast: The relevant LDCs provided load forecasts for their respective load supply stations in the ELS Region for the ten (10) year study period. The IESO provided a Conservation and Demand Management ("CDM") and Distributed Generation ("DG") forecast for the ELS region. The region's extreme summer and winter non-coincident peak gross load forecasts for each station were prepared by applying the LDC load forecast load growth rates to the actual 2018 summer and 2017/2018 winter peak extreme weather corrected loads, with Hydro One providing extreme weather correction factors. The net extreme weather summer and winter load forecasts were then produced by subtracting the percentage CDM reduction, and the amount of effective DG capacity from each station's gross load forecast. These extreme weather summer and winter load forecasts for the individual stations in the East Lake Superior region are given in Appendix A;
- Relevant information regarding system reliability and operational issues in the region; and
- List of major high voltage transmission equipment planned and/or identified to be refurbished and/or replaced due to the end of their useful life which is relevant for regional planning purposes. This includes transformers, autotransformers, Breakers, and overhead lines.

A technical assessment of needs was undertaken based on:

i. Planning criteria outlined in IESO-ORTAC (section 2.7.2) for analysis of current and future station capacity and transmission adequacy;
ii. Planning criteria outlined in IESO-ORTAC (section 7) for system reliability and operational concerns;
iii. Analysis of major high voltage equipment reaching the end of their life, in conjunction with emerging system needs; and
iv. Analysis of operational concerns relevant to Regional Planning.

In addition, the following assumptions were made in this Needs Assessment:

- The new East-West Tie Transmission Reinforcement is included in the assessment model.

- The region is winter peaking, but the study includes both winter and summer peak loads with interface transfer at normal limits to investigate effects of equipment limit changes relative to different seasonal peaks.

- Adequacy of transformation capacity at load stations was assessed assuming a 0.9 lagging power factor and non-coincident station loads.

- Adequacy of the following transmission lines capacity was assessed assuming a 0.9 lagging power factor and non-coincident station peak load due to the radial nature of the connections:

    - 115kV GL1SM (Third Line TS x St. Mary's MTS)
    - 115kV GL2SM (Third Line TS x St. Mary's MTS)
    - 115kV GL1TA (Third Line TS x Tarentorus MTS)
    - 115kV GL2TA (Third Line TS x Tarentorus MTS)

- Adequacy of transformation capacity for 230/115kV autotransformers T1 and T2 at Third Line TS, as well as transmission lines adequacy (excluding the above) were assessed using coincident system peak load in different seasons. Furthermore, this assessment investigated network capacity based on two (2) different configurations of the No.3 Sault circuit:

    - No.3 Sault circuit is connected radially to MacKay CGS G3 until 2022 with limited capacity;
    - No.3 Sault circuit is not radially connected to MacKay CGS G3 from 2022 onwards to 2028, with current capacity restrictions removed (restore to original capacity).

  Subsequently, four (4) major scenarios were investigated per season:

East – West Tie (Flow West)		East – West Tie (Flow East)	
No.3 Sault Radial	No.3 Sault Not Radial	No.3 Sault Radial	No.3 Sault Not Radial

- For the Sault Ste. Marie area, hydro generation is assumed to be at 98% dependable when all elements are in service, as well as during N-1 contingency analysis as per IESO-ORTAC. Hydro generation stations with water storage capacity (ie: Aubery Falls GS and Wells GS) typically generates at peak. Half of its respective generation capacity (equivalent to 1 unit) is assumed available when assessing autotransformer and transmission line adequacies.

- One of the industrial customers in the Sault Ste. Marie area has acquired Lake Superior Power ("LSP") Generating Station. There is currently a project to re-route two (2) of LSP's generators as embedded generation, with the remaining generator to be re-connected to Clergue TS via 115kV No. 1 and No. 2 CoGen circuits. In developing the worst case base case scenario, the study assumed generation from LSP to be unavailable.

7 NEEDS

This section assess the adequacy of regional infrastructure to met the forecasted load in the East Lake Superior Region and identify needs. The section also reviews and/or reaffirms needs previously identified in the last cycle of regional planning.

7.1 Review of Needs Identified in the Previous Cycle of Regional Planning

This section review the status of the needs identified in the previous cycle of Region Planning as summarized in Table 2 below.

Table 2: Needs Identified in the First Cycle Regional Planning Cycle

Type of Needs identified in the first RP cycle	Needs Details	Current Status
Transmission Supply Capacity of Hollingsworth TS / Anjigami TS Transformers	Overloading at Anjigami T1/ Hollingsworth T2	Pending confirmation for new customer connection
Transmission Supply Capacity of No. 1 Algoma Circuit	Thermal overloading on No. 1 Algoma circuit upon Breaker 214 Fail Contingency, where No. 2 and No. 3 Algoma lines will be removed from service	Continue to work with impacted customers to arrive at mutually agreeable solution.
Transmission Supply Reliability	Echo River TS – Single Transformer Supply	Transmitter and affected LDC have developed project scope for the installation of an additional transformer

a. Transmission Supply Capacity of Hollingsworth TS and Anjigami TS

Based on the previous NA, Hollingsworth TS – Transformer T2 / Anjigami TS – Transformer T1 will become overloaded due to a large customer connecting to the 44kV system. The customer has since put the connection application on hold. This need will be studied within the load connection process when the customer decides to proceed.

b. Transmission Supply Capacity of No. 1 Algoma Circuit

Based on the previous NA, No.1 Algoma Circuit may become overloaded after a breaker fail contingency at Patrick St. TS that removes No.2 Algoma and No.3 Algoma circuits by configuration. This overload is observed depending on the amount of load supplied from Patrick St. TS. This overload continues to be observed; refer to section 7.3 of this report for details.

c. Transmission Supply Reliability

Based on the previous NA, load restoration criteria cannot always be met at Echo River TS upon a transformer failure. HOSSM has been working with the impacted LDC, where HOSSM has developed and discussed different options that varies in levels of reliability and cost. HOSSM and the impacted LDS have come to an agreement to install a second transformer to improve reliability to load. The decision is reflected in HOSSM's and LDC's recent rate application.

7.2 Assessment of Transmission Capacity Needs in the Region

230kV Connection Facilities

Based on the demand forecast, there is sufficient step-down transformation capacity throughout the study period at Echo River TS.

Voltage performance for the 230kV system is within the ORTAC guidelines upon observing N-1 contingencies, and after taking control actions such as switching in and out shunt capacitor banks at Wawa TS or Third Line TS.

230/115kV Auto-transformation Facilities

Third Line TS
No capacity concerns when both Third Line autotransformers are in-service.

Upon N-1 contingency, autotransformers at Third Line TS will approach their 10-Day Limited Time Ratings (LTRs) by Winter 2022. The loading on the companion bank, subjected to different circuit configurations, is as follows:

No.3 Sault 3 Radial		**No.3 Sault 3 Not Radial**	
All elements in service	**N-1 (Third Line TS Autotransformer Contingency)**	**All elements in service**	**N-1 (Third Line TS Autotransformer Contingency)**
Third Line Autotransformer within its Continuous Rating	290.45MVA (100% of 10 day LTR)	Third Line Autotransformer within its Continuous Rating	273.57MVA (94.3% of 10-Day LTR)

The overload of Third Line TS auto-transformers is a capacity need.

MacKay TS
Prior to year 2022, no overloading on 115 kV circuit No.3 Sault is observed for loss of MacKay Transformer T2 due to No.3 Sault's radial configuration. Post year 2022, after No. 3 Sault line is no longer radially connected to Mackay G3, overloading of No. 3 Sault upon loss of T2 or upon loss of 230 kV circuit K24G will be mitigated by arming the existing MacKay TS Generation Rejection (G/R) Scheme.

115kV Connection Facilities

Based on the demand forecast, there is sufficient transformation and circuit capacity throughout the study period for 115kV connected load stations.

Voltage performance for the 115kV system is within the ORTAC guidelines upon N-1 contingencies

Load Security

As per IESO ORTAC criteria:

Criteria 1: With all transmission facilities in-service and coincident with an outage of the largest local generation unit, equipment within continuous rating, voltages must be within normal ranges, and transfers must be within applicable normal condition.

Assessment

- in the 230 kV system the largest unit is a Wells GS G1 or G2 unit;
- in the 115 kV system the largest unit is Clergue GS G2;

Under both outage scenarios, all equipment are within their continuous ratings, voltages are within normal ranges, and transfers are within applicable normal conditions. Hence it is concluded that Criteria 1 is satisfied.

Criteria 2: With any one element out of service, all equipment and circuits within applicable limits and load curtailment/Load Rejection only for local generation outages. No more than 150MW of load may be interrupted by configurations and by planned load curtailment or load rejections.

Assessment

- No more than 150MW is loss by configuration or load rejection. Therefore Criteria 2 is satisfied.

Criteria 3: With any two elements out of service, all equipment and circuits within applicable limits by time afforded by short-term ratings. Planned load curtailment or L/R exceeding 150 MW permissible for only local generation outages, and not more than 600 MW of load interrupted by configuration, by planned load curtailment or Load Rejection.

Assessment

- The projected regional gross load at coincident peak is forecasted at 377MW in 2028.
- Approximately 70MW of load will be rejected for a breaker fail contingency at Patrick St TS. If breaker 214 fails to open, both No.2 and No.3 Algoma circuits will be loss by configuration. This results in overload of No.1 Algoma circuit. This load rejection is required to decrease area loading in order to respect No. 1 Algoma circuit's long-term emergency rating of 128MVA. The impact is currently being assessed in a pending System Impact Assessment (SIA) from the IESO.
- Loss of 230kV P21G and P22G due a common tower contingency, or loss of both T1 and T2 Autotransformer at Third Line TS, will trigger instantaneous load rejections schemes at Third Line TS. At 98% dependable hydro generation, approximately 103MW of planned load curtailment or load rejection is required to bring the system to within applicable rating. It is expected that continued reliance on this load rejection scheme is necessary.
- Therefore, no more than 600MW of load will be interrupted by configuration, and no more than 150MW will be rejected by planned load curtailment or L/R scheme. It is concluded that Criteria 3 is satisfied.

Load Restoration

The ELS region has multiple radial single circuit and/or single transformer load connection stations where load loss is anticipated after a single transformer and/or single circuit contingency. At these locations ORTAC restoration criteria of 8 hours may not always be met. Stations that are impacted include:

- Andrew TS
- Batchawana TS
- Goulais TS

There is a need to review load restoration reliability at these stations.

The loss of 230kV P21G and P22G due a common tower contingency, or loss of both T1 and T2 Autotransformer at Third line TS, will trigger instantaneous load rejections schemes at Third Line TS. Loss of P21G and P22G will only take T1 out by configuration. Load restoration after operation of planned load curtailment / L/R scheme can proceed gradually via remaining 230kV connection (K24G and T2). Load restoration upon loss of both T1 and T2 will proceed gradually on HOSSM 115kV system via No.3 Sault circuit and Clergue GS. Therefore, ORTAC load restoration requirements are met.

7.3 Sensitivity Analysis

This Needs Assessment is subject to local area contingency criteria. To bridge the gap between regional and bulk system planning, the following bulk power system contingencies were assessed:

- Loss of No.2 and No.3 Algoma Lines due to Breaker 214 failure

Observations are as follows:

Based on the load forecast, a breaker failure contingency of circuit breaker 214 at Patrick St TS will remove No. 2 and No. 3 Algoma lines simultaneously by configuration, causing an overload on No. 1 Algoma circuit. The impact is also being investigated in a pending IESO's System Impact Assessment (SIA).

7.4 Assessment of End-Of-Life (EOL) Equipment Needs in the Region

HOSSM and LDCs have provided high voltage asset information under the following categories that have been identified at this time and are likely to be replaced over the next ten (10) years:

- Autotransformers
- Power Transformers

- HV and LV Breakers
- Transmission Circuits
- Protection System

Accordingly, following major high voltage equipment has been identified as approaching its EOL over the next 10 years.

Table 3: End-of-Life Equipment – East Lake Superior Region

EOL Asset Replacement/ Refurbishment	Replacement / Refurbishment Timing	Notes
Projects in Execution		
DA Watson TS – Protection Upgrade	End of 2019	This project is discussed further in Section 7.4.1
Future Projects		
Echo River TS – Breaker Replacement	2021	These Project are discussed further in Section 7.4.2
No.3 Sault Conductor and Structure Replacement	2022	
Third Line TS – Autotransformer T2 & Protection Replacement	2024	
Patrick St TS – HV Breaker Replacement	2024	
Batchawana TS / Goulais Bay TS – Station Refurbishment	2024	
Northern Ave TS – Transformer T1 Replacement	2024	
DA Watson TS – Metalclad Switchgear Replacement	2025	
Clergue TS – Switchgear Replacement	2026	

The EOL assessment for the above high voltage equipment included consideration of the following options:

1. Maintaining the status quo;
2. Replacing equipment with similar equipment of lower ratings (right-sizing) due to forecasted decrease in demand and built to current standards;

3. Replacing equipment with lower ratings (right-sizing) and built to current standards by transferring portions of load to other existing facilities;
4. Eliminating equipment by transferring all of the load to other existing facilities;
5. Replacing equipment with similar equipment and built to current standards (i.e. “like-for-like” replacement);
6. Replacing equipment with higher ratings (right-sizing) due to forecasted increase in demand or due to load transfer and built to current standards; and
7. Station reconfiguration

From HOSSM’s perspective as a facility owner and operator of its transmission equipment, status quo is generally not an option for major high voltage equipment due to safety and reliability risk of equipment failure.

7.4.1 Projects in Execution

The following EOL refurbishment project is currently under execution. Since the completion of the last RP, the need for proceeding with this project arose before the initiation of the second RP cycle. Hence, the following project was not listed or discussed during the first cycle of regional planning and are currently in execution:

DA Watson TS – Protection Upgrade

DA Watson TS is an 115kV station that connects multiple local hydraulic generating stations to HOSSM transmission system. Protection relays at DA Watson TS are at increased risk of failure and have been deemed obsolete by their manufacturer with limited spares parts and technical support available. In addition, the high arc flash hazard rating of the existing DA Watson TS metalclad switchgear compromises equipment integrity, system stability and worker safety.

The scope of work includes installing modern protection relays with arc flash detection mounted in racks located away from the metalclad switchgear. These new relays will also directly communicate with Hydro One’s Network Management System (NMS) utilizing the OC3 SCADA network.

7.4.2 New Needs

The following EOL refurbishment needs have been identified in the current regional planning cycle:

1. **Echo River TS – Breaker Replacement**

Echo River TS is a 230kV load supply station. The station consists of a single step-down transformer and a single 230kV circuit breaker to supply two (2) 34.5 kV customer feeders. Based on results of an asset condition assessment, the 230 kV circuit breaker is currently in deteriorating condition. This breaker is a live tank minimum oil breaker, which is considered obsolete and is due for replacement.

In consultation with the affected LDC, the breaker replacement will be coordinated with the other need at Echo River TS. The planned in-service year is 2021.

2. No.3 Sault Conductor and Structure Replacement

No.3 Sault is a 115kV transmission circuit that runs from MacKay TS 115kV station yard to Third Line TS 115kV station yard. This circuit provides an alternative path for local generation to reach load centres close to the Sault Ste. Marie area. Based on an asset condition assessment, No.3 Sault circuit is currently rated between “Poor” and “Very Poor” as it has multiple component (sleeves) failures and aging conductors. This circuit also accounts for 39% of all line equipment related outages experienced over the 2013 – 2017 period. The circuit is currently de-rated as a pre-cautionary action to minimize further stress.

The EOL replacement work of approximately 70km of conductor from Batchawana TS to MacKay TS includes replacing selected wood poles along the corridor as condition warrants. The planned in-service date is 2022. Based on load forecast, similar conductor ratings are expected. Due to the urgency the replacement, line rating will be reviewed within timeline afforded by the project.

3. Third Line TS – Autotransformer T2 & Protection Replacement

Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Third line TS 115kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, No.3 Sault circuit and Northern Ave circuit. It also supplied two (2) LDC HV load supply stations via 115kV circuits GL1SM GL2SM, GL1TA, and GL2TA. Based on an asset condition assessment, autotransformer T2 is approaching its EOL.

Based on the load forecast, similar ratings are required for the EOL autotransformer T2 replacement. While it is recognized that there is a capacity related need at the station as per Section 7.2 (to be considered in the Scoping Assessment Phase), the replacement of T2 will not alleviate the capacity need, as the replacement transformer (with similar ratings) is the largest standard size autotransformer available. To maintain supply reliability in the ELS Region, the planned in-service date for replacing T2 autotransformer and associated EOL protections is year 2024.

4. **Patrick St TS – HV Breaker Replacement**

Patrick St TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2 and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No .1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area.Based on an asset condition assessment, four (4) out of thirteen (13) 115kV breakers are minimum oil live tank breakers and they are considered obsolete.

Based on the load forecast and expected system conditions, similar equipment ratings are required for EOL replacement. The current plan is to replace these four (4) obsolete breakers with new SF6 breakers, complete with new breaker disconnect switches. The planned in-service date for this project is 2024.

5. **Batchawana TS / Goulais Bay TS – Station Refurbishment**

Batchawana TS and Goulais Bay TS are load supply stations that are in proximity of each other, and both are connected to 115kV No.3 Sault circuit. Each station is currently configured with a single transformer supply. Based on an asset condition assessment, both stations are in a deteriorated state with obsolete equipment including power transformers, protections (fuse), batteries, chargers, and remote terminal units.

The scope of refurbishment is still under development, with different options under evaluation. HOSSM is actively engaging the local LDC to arrive at a mutually agreeable solution. The planned completion date for this refurbishment is anticipated to be 2024.

6. **Northern Ave TS – Transformer T1 Replacement**

Northern Ave TS is a 115kV load supply station that is connected to Third Line TS via 115kV Northern Ave circuit. Northern Ave Transformer T1 is a 115/34.5kV, 20/26.7MVA step down transformer that supplies Algoma Power Inc. via one (1) 34.5kV feeder. Transformer T1 has been in-service since the 1970’s, and it is now approaching its EOL.

Based on the load forecast, similar equipment ratings are required for EOL replacement. The current plan of replacing T1 and associated equipment has an in-service date of year 2024.

7. **DA Watson TS – Metalclad Switchgear Replacement**

DA Watson TS is a 115kV load supply station that also has connectivity with three (3) local hydro generating stations. The station has two 45/60/75 MVA transformers and nine 34.5kV feeders. Based on an asset condition assessment, the existing metalclad feeder breakers are obsolete and near EOL.

Based on the load forecast and expected system conditions, similar ratings are required for EOL feeder breaker replacements. The planned in-service date to replace existing metalclad breakers and associated equipment at DA Watson TS is year 2025.

8. Clergue TS – Switchgear Replacement

Clergue TS is a 115kV station that connects Clergue Generating Station and LSP co-generation station to the HOSSM system via two (2) 115kV circuits emanating from Patrick St TS. Based on an asset condition assessment, the existing 12 kV minimum-oil metal-clad switchgear is obsolete and approaching EOL.

Based on the load forecast and expected system conditions, similar equipment ratings are required for EOL replacement. The planned in-service date to replace the metalclad switchgear and associated equipment is year 2026.

8 CONCLUSION AND RECOMMENDATIONS

Based on the findings of the Needs Assessment, the study team recommends the following:

1. The overload of the 230/115 kV auto-transformers at Third Line TS requires further regional coordination in the Scoping Assessment phase of Regional Planning to determine the best study approach to address the need. IESO will lead the Scoping Assessment phase.

2. Reliability to load at Andrew TS, Batchawana TS and Goulais TS to be reviewed. The review to be conducted by the transmitter and impacted distributor to evaluate the local reliability needs on a case by case basis.

3. The implementation and execution for the replacement of the following EOL transmission assets will be coordinated between Hydro One Sault Ste. Marie and the affected LDCs and/or customers, where required. These projects will be coordinated with IESO where required and where feasible within the timelines afforded by each project.

    ii. Echo River TS – Breaker Replacement
    iii. No.3 Sault Conductor and Structure Replacement
    iv. Third Line TS – Autotransformer T2 & Protection Replacement
    v. Patrick St TS – HV Breaker Replacement
    vi. Batchawana TS / Goulais Bay TS – Station Refurbishment
    vii. Northern Ave TS – Transformer T1 Replacement
    viii. DA Watson TS – Metalclad Switchgear Replacement
    ix. Clergue TS – Switchgear Replacement

4. The overload of Algoma No. 1 Circuit due to breaker failure at Patrick St TS and/or other multiple elements contingencies required additional study. Further analysis in the Scoping Assessment phase of Regional Planning is required to determine the best planning approach while taking into account the outcome of an ongoing SIA for new load connection at Patrick St TS.

9 REFERENCES

[1] East Lake Superior Region Need Assessment Report – December 2014
https://www.hydroone.com/about/corporate-information/regional-plans/east-lake-superior

[2] Planning Process Working Group Report to the OEB - https://www.oeb.ca/oeb/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

[3] Ontario Resource and Transmission Assessment Criteria (ORTAC) – Issue 5.0 – August 2007
IESO_ORTAC_Issue_5.0_August_2007

Appendix A: East Lake Superior Region Winter & Summer Non-Coincident Load Forecast

Winter Non-Coincident Load Forecast [MW]

Transformer Station		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
St. Mary's MTS (T1/T2)	Gross	52.16	51.78	51.39	51.01	50.63	50.25	49.88	49.51	49.14	48.78	48.41
	CDM	19.49	19.49	19.49	19.49	19.49	19.49	19.49	19.49	19.49	19.49	19.49
	DG	0.61	1.10	1.11	1.12	1.18	1.21	1.25	1.30	1.35	1.37	1.30
	Net	33.60	32.68	32.27	31.85	31.40	30.97	30.54	30.10	29.66	29.26	28.95
St. Mary's MTS (T3/T4)	Gross	51.97	51.58	51.20	50.82	50.44	50.06	49.69	49.32	48.96	48.59	48.23
	CDM	19.57	19.57	19.57	19.57	19.57	19.57	19.57	19.57	19.57	19.57	19.57
	DG	0.61	1.10	1.10	1.12	1.17	1.20	1.25	1.29	1.35	1.36	1.29
	Net	31.79	30.92	30.53	30.13	29.70	29.29	28.88	28.47	28.04	27.66	27.37
Tarentorus MTS (T1/T2)	Gross	64.35	63.87	63.40	62.93	62.46	61.99	61.53	61.08	60.62	60.17	59.72
	CDM	19.56	19.56	19.56	19.56	19.56	19.56	19.56	19.56	19.56	19.56	19.56
	DG	0.76	1.36	1.37	1.39	1.45	1.49	1.55	1.60	1.67	1.69	1.60
	Net	43.08	42.03	41.55	41.07	40.55	40.06	39.55	39.06	38.54	38.08	37.73
Tarentorus MTS (T3/T4)	Gross	69.04	68.52	68.02	67.51	67.01	66.51	66.01	65.52	65.04	64.55	64.07
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.81	1.46	1.47	1.49	1.56	1.60	1.66	1.71	1.79	1.81	1.72
	Net	68.23	67.07	66.55	66.02	65.45	64.91	64.36	63.81	63.25	62.74	62.35
Andrews TS (T4)	Gross	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Net	0.22	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Batchawana TS	Gross	1.50	2.01	2.02	2.03	2.04	2.05	2.06	2.07	2.08	2.09	2.10
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.02	0.04	0.04	0.04	0.05	0.05	0.05	0.05	0.06	0.06	0.06
	Net	1.48	1.96	1.97	1.98	1.99	2.00	2.01	2.01	2.02	2.03	2.04
DA Watson CTS (T1/T2)	Gross	7.85	7.93	8.01	8.09	8.17	8.25	8.33	8.41	8.50	8.58	8.67
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.09	0.17	0.17	0.18	0.19	0.20	0.21	0.22	0.23	0.24	0.23
	Net	7.76	7.76	7.84	7.91	7.98	8.05	8.12	8.19	8.27	8.34	8.44
Echo River TS (T1)	Gross	12.61	12.74	12.87	13.00	13.13	13.26	13.39	13.52	13.66	13.80	13.93
	CDM	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	DG	0.15	0.27	0.28	0.29	0.31	0.32	0.34	0.35	0.38	0.39	0.37
	Net	12.36	12.37	12.49	12.61	12.72	12.84	12.95	13.07	13.18	13.31	13.46
Goulais Bay TS (T1)	Gross	9.01	9.10	9.19	9.28	9.38	9.47	9.56	9.66	9.76	9.85	9.95
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.11	0.19	0.20	0.20	0.22	0.23	0.24	0.25	0.27	0.28	0.27
	Net	8.90	8.91	8.99	9.08	9.16	9.24	9.32	9.41	9.49	9.57	9.68
Hollingsworth TS (T2) Anjigami TS (T1)	Gross	12.50	12.69	12.88	13.07	13.27	13.47	13.67	13.87	14.08	14.29	14.51
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.15	0.27	0.28	0.29	0.31	0.32	0.34	0.36	0.39	0.40	0.39
	Net	12.35	12.42	12.60	12.78	12.96	13.14	13.32	13.51	13.69	13.89	14.12
MacKay TS (T1)	Gross	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05	0.05
Northern Ave TS (T1)	Gross	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20

	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
	Net	0.20	0.20	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.19
Northern Ave TS (T2)	Gross	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41	2.41
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.03	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.06
	Net	2.38	2.36	2.36	2.36	2.35	2.35	2.35	2.35	2.34	2.34	2.35
Chapleau MTS	Gross	4.12	4.03	4.13	3.92	4.41	4.33	4.36	3.70	4.01	3.96	3.96
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.05	0.09	0.09	0.09	0.10	0.10	0.11	0.10	0.11	0.11	0.11
	Net	4.07	3.94	4.04	3.83	4.31	4.23	4.25	3.61	3.89	3.84	3.85
Chapleau DS	Gross	9.9	10.5	12.1	12.3	14.4	14.5	14.6	14.7	14.8	14.9	15.0
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.12	0.22	0.26	0.27	0.33	0.35	0.37	0.39	0.41	0.42	0.40
	Net	9.76	10.31	11.88	11.99	14.07	14.16	14.25	14.33	14.41	14.50	14.62
Patrick St TS	Gross	149.7	159.9	167.2	164.6	165.6	165.8	165.3	165.6	165.6	165.5	165.5
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	149.70	159.90	167.20	164.60	165.60	165.80	165.30	165.60	165.60	165.50	165.50
Wallace Terrace CTS	Gross	15.60	15.80	15.70	15.70	15.70	15.70	15.70	15.70	15.70	15.70	15.70
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	15.60	15.80	15.70	15.70	15.70	15.70	15.70	15.70	15.70	15.70	15.70

Summer Non-Coincident Load Forecast [MW}

Transformer Station		2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
St. Mary's MTS (T1/T2)	Gross	42.87	42.55	42.23	41.92	41.61	41.30	40.99	40.69	40.39	40.08	39.79
	CDM	19.61	19.61	19.61	19.61	19.61	19.61	19.61	19.61	19.61	19.61	19.61
	DG	0.50	0.91	0.91	0.92	0.97	0.99	1.03	1.06	1.11	1.12	1.07
	Net	22.76	22.04	21.72	21.39	21.04	20.70	20.36	20.02	19.67	19.36	19.11
St. Mary's MTS (T3/T4)	Gross	38.54	38.26	37.97	37.69	37.41	37.13	36.85	36.58	36.31	36.04	35.77
	CDM	19.66	19.66	19.66	19.66	19.66	19.66	19.66	19.66	19.66	19.66	19.66
	DG	0.45	0.81	0.82	0.83	0.87	0.89	0.93	0.96	1.00	1.01	0.96
	Net	18.43	17.78	17.49	17.19	16.88	16.57	16.27	15.96	15.65	15.37	15.15
Tarentorus MTS (T1/T2)	Gross	52.00	51.62	51.23	50.85	50.47	50.10	49.73	49.36	48.99	48.63	48.26
	CDM	19.75	19.75	19.75	19.75	19.75	19.75	19.75	19.75	19.75	19.75	19.75
	DG	0.61	1.10	1.10	1.12	1.17	1.21	1.25	1.29	1.35	1.36	1.30
	Net	31.64	30.77	30.38	29.98	29.55	29.14	28.72	28.31	27.89	27.51	27.22
Tarentorus MTS (T3/T4)	Gross	52.32	51.94	51.55	51.17	50.79	50.41	50.03	49.66	49.29	48.93	48.56
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.62	1.11	1.11	1.13	1.18	1.21	1.26	1.30	1.36	1.37	1.30
	Net	51.71	50.83	50.44	50.04	49.61	49.20	48.78	48.36	47.94	47.55	47.26
Andrews TS (T4)	Gross	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24	0.24
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01
	Net	0.24	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23	0.23
Batchawana TS	Gross	1.56	1.57	1.59	1.61	1.62	1.64	1.65	1.67	1.69	1.70	1.72
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.05	0.05	0.05
	Net	1.54	1.54	1.56	1.57	1.58	1.60	1.61	1.63	1.64	1.65	1.67
DA Watson CTS (T1/T2)	Gross	5.11	5.16	5.22	5.27	5.32	5.37	5.43	5.48	5.54	5.59	5.65
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.06	0.11	0.11	0.12	0.12	0.13	0.14	0.14	0.15	0.16	0.15
	Net	5.05	5.05	5.11	5.15	5.20	5.24	5.29	5.34	5.39	5.43	5.50
Echo River TS (T1)	Gross	13.50	13.63	13.77	13.91	14.05	14.19	14.33	14.47	14.62	14.76	14.91
	CDM	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10	0.10
	DG	0.16	0.29	0.30	0.31	0.33	0.34	0.36	0.38	0.40	0.41	0.40
	Net	13.24	13.24	13.37	13.50	13.62	13.75	13.87	13.99	14.12	14.25	14.41
Goulais Bay TS (T1)	Gross	4.74	4.78	4.83	4.88	4.93	4.98	5.03	5.08	5.13	5.18	5.23
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.06	0.10	0.10	0.11	0.11	0.12	0.13	0.13	0.14	0.15	0.14
	Net	4.68	4.68	4.73	4.77	4.82	4.86	4.90	4.95	4.99	5.03	5.09
Hollingsworth TS (T2) Anjigami TS (T1)	Gross	12.15	12.28	12.40	12.52	12.65	12.77	12.90	13.03	13.16	13.29	13.43
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.14	0.26	0.27	0.28	0.29	0.31	0.32	0.34	0.36	0.37	0.36
	Net	12.01	12.02	12.13	12.24	12.36	12.46	12.58	12.69	12.80	12.92	13.07
MacKay TS (T1)	Gross	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03
Northern Ave TS (T1)	Gross	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.01	0.01	0.01
	Net	0.20	0.20	0.20	0.20	0.20	0.20	0.19	0.19	0.19	0.19	0.19
Northern Ave TS (T2)	Gross	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45	2.45

	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.03	0.05	0.05	0.05	0.06	0.06	0.06	0.06	0.07	0.07	0.07
	Net	2.42	2.40	2.40	2.40	2.39	2.39	2.39	2.39	2.38	2.38	2.38
Chapleau MTS	Gross	2.36	2.19	2.02	2.06	2.51	1.90	1.62	2.06	2.05	2.02	2.02
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.03	0.05	0.04	0.05	0.06	0.05	0.04	0.05	0.06	0.06	0.05
	Net	2.33	2.14	1.98	2.02	2.45	1.85	1.58	2.01	2.00	1.96	1.96
Chapleau DS	Gross	7.4	8.0	9.6	9.7	11.8	11.9	12.0	12.1	12.1	12.2	12.3
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.09	0.17	0.21	0.21	0.27	0.29	0.30	0.32	0.33	0.34	0.33
	Net	7.31	7.83	9.39	9.49	11.53	11.61	11.70	11.78	11.77	11.86	11.97
Patrick St TS	Gross	147.8	156.4	160.5	160.6	160.8	160.6	160.7	160.7	160.7	160.7	160.7
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	147.83	156.41	160.52	160.59	160.84	160.65	160.69	160.73	160.69	160.70	160.70
Wallace Terrace CTS	Gross	15.33	15.43	15.70	15.49	15.54	15.50	15.53	15.55	15.52	15.53	15.53
	CDM	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	DG	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Net	15.33	15.43	15.70	15.49	15.54	15.50	15.53	15.55	15.52	15.53	15.53

Appendix B: Lists of Step-Down Transformer Stations

Sr. No.	Transformer Stations
1.	Andrew TS
2.	Anjigami TS
3.	Batchawana TS
4.	Chapleau DS
5.	Chapleau MTS
6.	Clergue TS
7.	DA Watson TS
8.	Echo River TS
9.	Flakeboard CTS
10.	Gold Mines CTS
11.	Goulais Bay TS
12.	Hollingsworth TS
13.	MacKay TS
14.	Northern Ave TS
15.	Patrick St TS
16.	Rentech CTS
17.	St. Mary's MTS
18.	Tarentorus MTS
19.	Third Line TS
20.	Wallace Terrace CTS
21.	Wawa TS

Appendix C: Lists of Transmission Circuits

Sr. No.	Circuit ID	From Station	To Station	Voltage (kV)
1.	K24G	Third Line TS	MacKay TS	230
2.	P21G	Third Line TS	Mississagi TS	230
3.	P22G	Third Line TS	Mississagi TS	230
4.	P25W	Mississagi TS	Wawa TS	230
5.	P26W	Mississagi TS	Wawa TS	230
6.	T27P	Mississagi TS	Wells CGS	230
7.	T28P	Mississagi TS	Wells CGS	230
8.	W21M	Marathon TS	Wawa TS	230
9.	W22M	Marathon TS	Wawa TS	230
10.	W23K	MacKay TS	Wawa TS	230
11.	No.1 ALGOMA	Third Line TS	Patrick St TS	115
12.	No.2 ALGOMA	Third Line TS	Patrick St TS	115
13.	No.3 ALGOMA	Third Line TS	Patrick St TS	115
14.	ANDREWS1	Andrews TS	Andrews CGS	115
15.	CLERGUE1	Patrick St TS	Clergue TS	115
16.	CLERGUE2	Patrick St TS	Clergue TS	115
17.	No.1 COGEN	Clergue TS	Lake Superior CGS	115
18.	No.2 COGEN	Clergue TS	Lake Superior CGS	115
19.	GARTSHO1	MacKay TS	Gartshore SS	115
20.	GARTSHO2	MacKay TS	Gartshore SS	115

21.	GARTSHO3	Gartshore SS	Gartshore GS	115
22.	GL1SM	Third Line TS	St. Mary’s MTS	115
23.	GL1TA	Third Line TS	Tarentorus MTS	115
24.	GL2SM	Third Line TS	St. Mary’s MTS	115
25.	GL2TA	Third Line TS	Tarentorus MTS	115
26.	HARRIS1	Magpie SS	Harris CGS	115
27.	HIGHFAL1	Anjigami TS	DA Watson TS	115
28.	HIGHFAL2	Anjigami TS	DA Watson TS	115
29.	HLNGWTH1	Hollingsworth TS	Wawa TS	115
30.	HOGG1	Gartshore SS	Hogg CGS	115
31.	LEIGHBY1	Patrick St TS	Flakeboard CTS	115
32.	MAGPIE1	DA Watson TS	Magpie SS	115
33.	MISSION1	Magpie SS	Misson Falls CGS	115
34.	No.3 SAULT	MacKay TS	Third Line TS	115
35.	STEEPHL1	Magpie SS	Steephill Falls CGS	115
36.	W2C	Wawa TS	Chapleau DS	115

Appendix D: Lists of LDCs in the East Lake Superior Region

SR. NO.	COMPANY	CONNECTION TYPE (TX / DX)
1.	ALGOMA POWER INC.	TX
2.	CHAPLEAU PUC	TX
3.	HYDRO ONE NETWORKS INC. (DISTRIBUTION)	TX
4.	SAULT STE. MARIE PUC	TX

Appendix E: Acronyms

Acronym	Description
A	Ampere
BES	Bulk Electric System
BPS	Bulk Power System
CDM	Conservation and Demand Management
CIA	Customer Impact Assessment
CGS	Customer Generating Station
CSS	Customer Switching Station
CTS	Customer Transformer Station
DESN	Dual Element Spot Network
DG	Distributed Generation
DS	Distribution Station
GS	Generating Station
HV	High Voltage
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LP	Local Plan
LTE	Long Term Emergency
LTR	Limited Time Rating
LV	Low Voltage
MTS	Municipal Transformer Station
MW	Megawatt
MVA	Mega Volt-Ampere
MVAR	Mega Volt-Ampere Reactive
NA	Needs Assessment
NERC	North American Electric Reliability Corporation
NGS	Nuclear Generating Station
NPCC	Northeast Power Coordinating Council Inc.
NUG	Non-Utility Generator
OEB	Ontario Energy Board
OPA	Ontario Power Authority
ORTAC	Ontario Resource and Transmission Assessment Criteria
PF	Power Factor
PPWG	Planning Process Working Group
RIP	Regional Infrastructure Plan
SA	Scoping Assessment
SIA	System Impact Assessment
SPS	Special Protection Scheme
SS	Switching Station
STG	Steam Turbine Generator
TS	Transformer Station

Appendix C

East Lake Superior Region Scoping Assessment

East Lake Superior Region Scoping Assessment Report

October 4, 2019

Table of Contents

Summary			
Region	East Lake Superior		
Start Date	July 2, 2019	**End Date**	October 3, 2019

1 Introduction

This Scoping Assessment Outcome Report is part of the Ontario Energy Board's (OEB) regional planning process. The OEB endorsed the Planning Process Working Group's Report[1] in May 2013 and formalized the process and timelines through changes to the Transmission System Code and Distribution System Code in August 2013.

The first cycle of the regional planning process for the East Lake Superior (ELS) region was completed in December 2014. The 2014 Needs Assessment (NA) recommended that the potential needs identified be addressed through the development of localized wires-only solutions. Further coordinated regional planning did not proceed following publication of the 2014 ELS NA report.

The second cycle of regional planning for the ELS region was initiated in April 2019 with the NA process. The first step in the regional planning process, the NA was carried out by the Study Team (defined in Section 2), and the resulting NA[2] report – which identified needs to be considered in the Scoping Assessment to determine the appropriate process to address them – was completed and issued in June 2019.

During the Scoping Assessment, the Study Team reviewed the nature and timing of the known needs in the region to determine the most appropriate planning approach going forward. This process also identified needs and considerations that were not included in the NA. The planning approaches considered include:

- An Integrated Regional Resource Plan (IRRP) – where a greater range of options, including non-wires, are considered and/or closer coordination with communities and stakeholders is required;
- A Regional Infrastructure Plan (RIP) – which considers more straightforward wires-only options with limited engagement; or
- A local plan undertaken by the transmitter and affected local distribution company (LDC)– where no further regional coordination is needed.

Additional information on selecting a planning approach can be found in Appendix B.

This Scoping Assessment report:

- Lists the needs identified in the NA report;
- Describes additional needs and considerations not identified in the NA report;
- Defines the geographic grouping of the needs into sub-regions, as applicable;
- Determines the appropriate regional planning approach and scope for identified needs;
- Creates a terms of reference for an IRRP; and
- Establishes the composition of the IRRP Working Group.

---

[1] Planning Process Working Group Report to the Board - The Process for Regional Infrastructure Planning in Ontario

[2] Needs Assessment Report - East Lake Superior Region

2 Study Team

The Scoping Assessment was carried out by the Study Team:

- Independent Electricity System Operator (IESO) (project lead)
- Hydro One Networks Sault Ste. Marie LP (HOSSM) (transmitter)
- Hydro One Networks Inc. (HONI) (transmitter)
- Algoma Power Inc.
- Chapleau PUC
- Hydro One Distribution
- Sault Ste. Marie PUC (SSM PUC)

3 Categories of Needs, Analysis and Results

3.1 Overview of the Region

The ELS region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south.

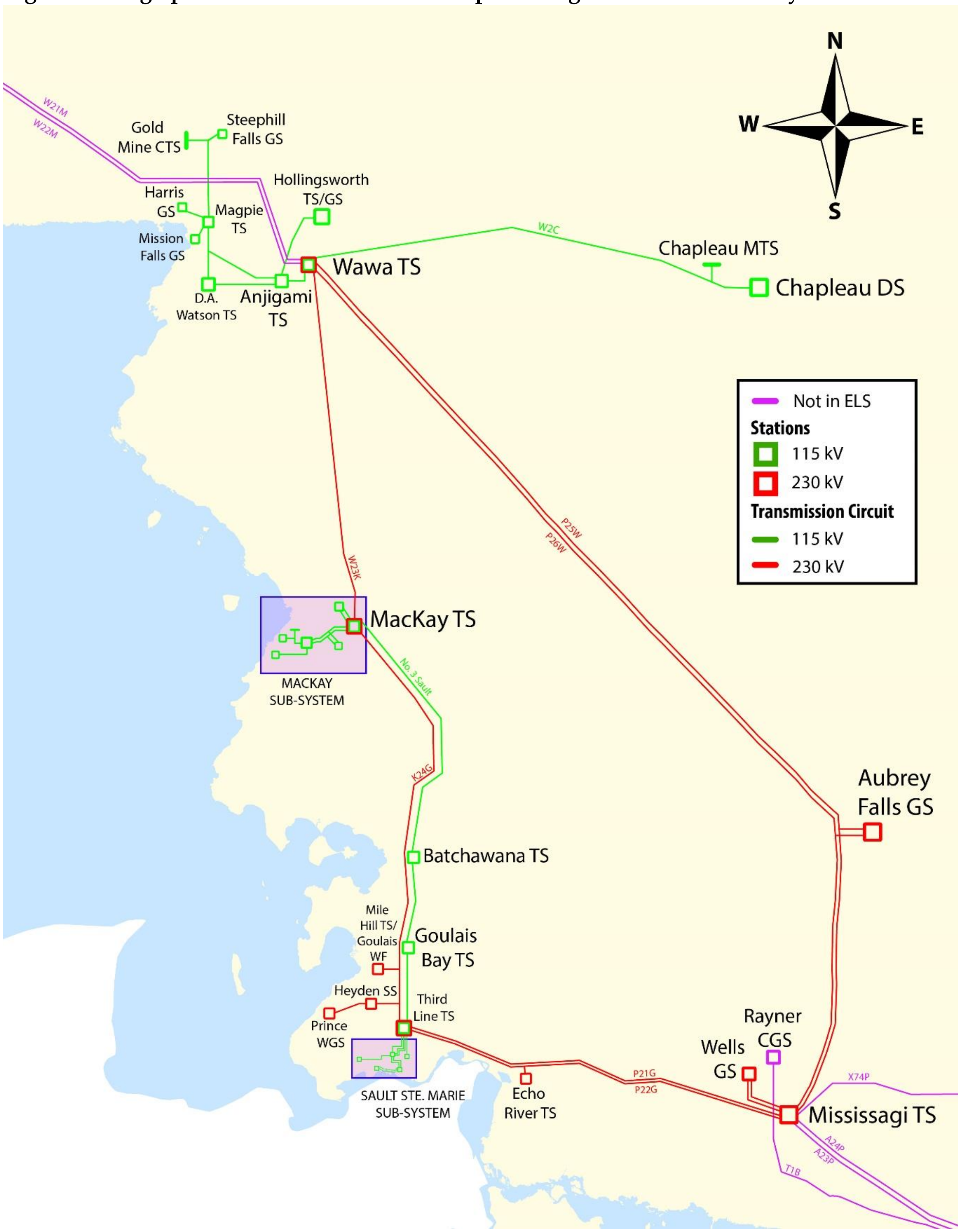
Electrical supply to the region is provided primarily through 230/115 kV autotransformers at Third Line TS, Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figures 1 and 2. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

The 230 kV transmission facilities in this area provide both bulk system and regional system functions. That is, in addition to delivering reliable supply to local customers, they also form part of an integrated network that enables the bulk transfer of electricity across the province. Although the bulk transmission system is not the focus of regional planning, it impacts how the system is modelled and studied.

The region has over 1,200 MW of generation, including numerous hydroelectric facilities, solar and wind farms and thermal generating facilities. The transmitters in the region are Hydro One Sault Ste. Marie LP (HOSSM) and Hydro One Networks Inc. (Hydro One); the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and Sault Ste. Marie PUC.

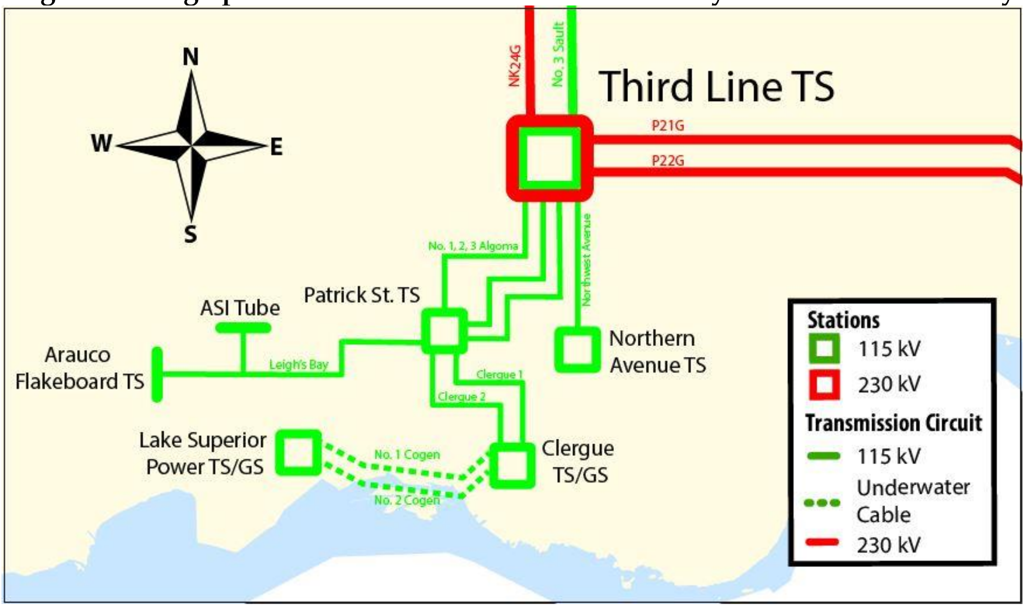
Geographic layouts of the electricity infrastructure supplying the region are shown in Figures 1, 2 and 3. An electrical single line diagram (SLD) for the same area is shown in Figure 4.

Figure 1: Geographical Area of the East Lake Superior Region with Electrical Layout



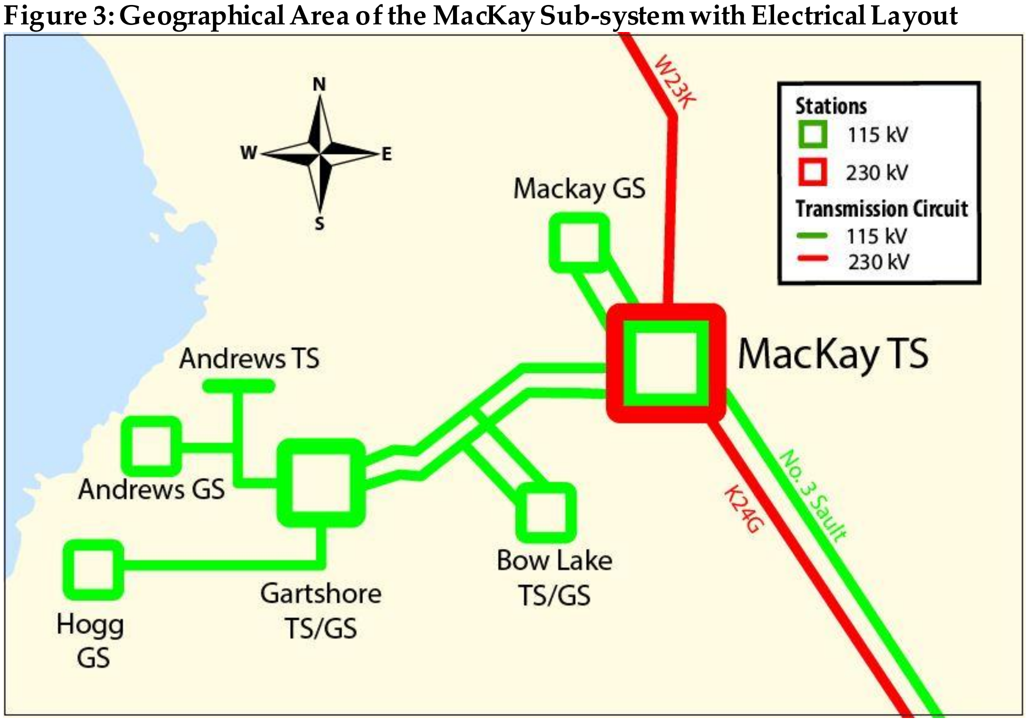
Source: IESO

Figure 2: Geographical Area of the Sault Ste Marie Sub-system with Electrical Layout



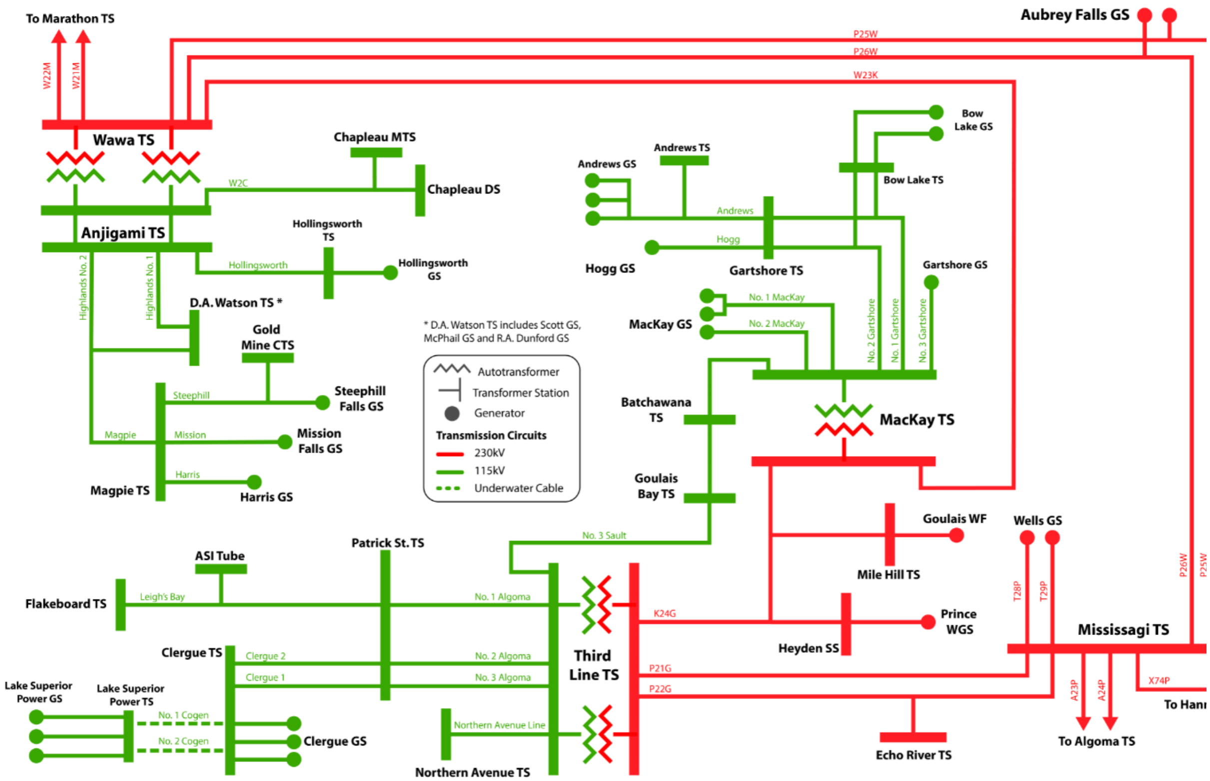
Source: IESO

Figure 3: Geographical Area of the MacKay Sub-system with Electrical Layout



Source: IESO

Figure 4: East Lake Superior Region Single Line Diagram



Source: IESO

3.2 Background

The first cycle of the regional planning process for the region was initiated by the former Great Lakes Power Transmission (GLPT) in October 2014 and completed in December 2014 with the publication of the 2014 NA report. The report identified a number of potential needs and recommended addressing them through the development of localized wires-only solutions. Further coordinated regional planning did not proceed following publication of the report.

In 2016, Hydro One acquired GLPT and renamed the company Hydro One Sault Ste. Marie LP. The second cycle of regional planning was kicked off by HOSSM in April 2019 and the 2019 NA report was published in June 2019. The needs identified in this report form the basis of the analysis for this Scoping Assessment and are discussed in further detail in Section 3.3.

3.3 Needs Identified

The 2019 NA report identified a number of needs based on studies performed during the needs assessment phase, current sustainment plans and a 10-year demand forecast. This section describes those needs.

3.3.1 Third Line TS Autotransformer Overload

Following the loss of one autotransformer at Third Line TS, the second autotransformer is expected to exceed its 10-day limited time rating (LTR) by 2022.

This need is exacerbated by the poor condition of the 115 kV circuit Sault No. 3, which is currently operated open until the conductor is replaced. The conductor is expected to be replaced by 2022 allowing it to be operated closed. This will reduce the need at Third Line TS, reducing loading on the autotransformers to 94 per cent of their 10-day LTR.

3.3.2 No. 1 Algoma Overload

No.1 Algoma is one of three 115 kV circuits supplying Patrick St TS from the Third Line 115 kV bus. Based on today's load, the loss of circuits No.2 Algoma and No.3 Algoma, or a breaker failure at Patrick St TS, can results in flows on No.1 Algoma exceeding the long-term emergency rating of the line.

3.3.3 Load Security and Restoration

Load restoration capability is the ability to restore power to those affected by a transmission outage within reasonable time frames. A restoration need emerges when load is interrupted following a transmission outage and supply cannot be restored within the timelines specified by the applicable planning criteria. These timelines are dependent on the amount of load being interrupted and proximity to maintenance crew and centres.

Load security needs emerge if the total amount of electricity supply at risk of interruption following a transmission outage exceeds the amounts permissible by the applicable planning criteria. The criteria identify areas where a supply outage could affect a vast number of customers, regardless of restoration time. Details on planning contingencies that must be considered, and associated restoration and security guidelines, are defined in Ontario Resource and Transmission Assessment Criteria (ORTAC).

The NA report identified load restoration needs following the loss of the step-down transformers at Andrew TS, Batchawana TS, Echo River TS or Goulais TS.

The NA report did not identify any load security needs; however subsequent studies identified a potential load security need[3] in the Sault Ste. Marie sub-system following the loss of both autotransformers[4] at Third Line TS.

3.3.4 End-of-Life Facility Needs

The need to replace aging transmission assets may present opportunities to better align investments with evolving power system priorities. This may involve up-sizing equipment in areas with capacity needs, downsizing or even removing equipment that is no longer required to supply needs.

[3] Ontario Resource and Transmission Assessment Criteria, Section 7.1, Load Security Criteria

[4] North American Electric Reliability Corporation (NERC) Standard TPL 001-4, Category P6 – Multiple Contingency (Two overlapping singles)

Facilities anticipated to be approaching end of life are summarized in Table 1.

Table 1: End-of-Life Facilities

Facilities	Target Date
DA Watson TS – Protection Upgrade	2019 (underway)
Echo River TS – Breaker Replacement	2021
Sault No. 3 Conductor and Structure Replacement	2022
Third Line TS – Autotransformer T2 & Protection Replacement	2024
Patrick St TS – HV Breaker Replacement	2024
Batchawana TS / Goulais Bay TS – Station Refurbishment	2024
Northern Ave TS – Transformer T1 Replacement	2024
DA Watson TS – Metalclad Switchgear Replacement	2025
Clergue TS – Switchgear Replacement	2026

With the exception of the Sault No. 3 conductor and structure replacement, which is expected to result in significant system reliability benefits, the anticipated facility replacements listed in Table 1 are unlikely to impact other system needs.

3.4 Other Needs and Considerations

The Study Team also identified other needs not captured in the Needs Assessment:

3.4.1 Unbundling of Embedded Generation

There are over 60 MW of solar PV generation facilities embedded in region's LDC service territories (primarily located in the SSM PUC sub-system) that are not visible to the IESO or HOSSM. The historic output of these generation facilities needs to be separated or "unbundled" from the historic demand on the transmission system (i.e., grid demand) to determine the impact of the embedded (or distributed) generation on reducing grid demand and contributing to the reliability of the local transmission system.

3.4.2 Expiration of Generation Contracts

Between 2029 and 2031, over 120 MW of IESO-contracted generation facilities in the SSM PUC sub-system will expire. The impact on regional supply and reliability if these generators do not continue to operate after contract expiry will need to be determined.

3.4.3 Ferrochrome Smelter

In May 2019, a potential industrial customer and the city of Sault Ste. Marie announced their plan to site a ferrochrome production facility in the city, with construction planned to begin in 2025. Depending on the connection configuration of the facility, this project could impact the reliability of the local transmission system and may require regional coordination.

3.5 Analysis of Needs and Planning Approach

3.5.1 Needs to be Addressed in Local Planning

A local planning process is recommended to address the restoration needs identified at Andrew TS, Batchawana TS, Echo River TS and Goulais TS, described in Section 3.3.3, as well as the end-of-life needs described in Section 3.3.4. The Study Team will monitor the sustainment plans for these facilities to ensure they are coordinated with the IRRP.

3.5.2 Needs to be Addressed in Integrated Regional Resource Plan (IRRP)

The remaining needs discussed in Section 3.3:

- Have the potential to be addressed, in whole or part, by non-wires solutions;
- Could be impacted by varying bulk systems flows;
- Could be addressed in a coordinated manner (e.g., one solution may be able to address multiple needs);
- Impact multiple LDCs in the region and
- Require ongoing engagement and coordination with community-level energy planning activities.

As these needs should be addressed in a coordinated manner, the Study Team recommends an IRRP be undertaken for the region.

4 Conclusion

The Scoping Assessment concludes that:

1. A coordinated regional planning approached is required and an IRRP is recommended for the ELS Region to address the:
   - Third Line TS autotransformer overload
   - No. 1 Algoma overload
   - Load security needs described in Section 3.3.3
   - Other needs and considerations described in Section 3.4

   It is important to note that this list of needs is not exhaustive, as further detailed evaluation undertaken through the IRRP may identify new needs, particularly those requiring consideration for the longer term. Additionally, the IRRP process allows for continuous coordination of information related to needs, timing, and potential solutions with the ongoing bulk transmission studies and end-of-life activities in the region.

   The draft Terms of Reference outlining the scope, objectives and timeline of the ELS IRRP can be found in Appendix A.

2. Local planning is recommended to address both the restoration needs identified at Andrew TS, Batchawana TS, Echo River TS and Goulais TS, described in Section 3.3.3, and the end-of-life needs described in Section 3.3.4. The Study Team will monitor the sustainment plans for these facilities to ensure they are coordinated with the IRRP.

List of Acronyms

CDM	Conservation and Demand Management
DG	Distributed Generation
ELS	East Lake Superior
EWTW	East West Transfer West
GLPT	Great Lakes Power Transmission
HONI	Hydro One Networks Inc.
HOSSM	Hydro One Sault Ste. Marie LP
IESO	Independent Electricity System Operator
IRRP	Integrated Regional Resource Plan
kV	kilovolt
LDC	Local Distribution Company
LTR	Limited Time Rating
MW	Megawatt
NERC	North American Electric Reliability Corporation
NUG	Non-Utility Generator
NA	Needs Assessment
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board
ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
TS	Transformer Station

Appendix A: The East Lake Superior IRRP Terms of Reference

1. Introduction and Background

These Terms of Reference establish the objectives, scope, key assumptions, roles and responsibilities, activities, deliverables and timelines for an Integrated Regional Resource Plan (IRRP) for the East Lake Superior (ELS) region.

Based on the needs identified through the Needs Assessment (NA) process, and further investigation through the Scoping Assessment, the Study Team recommended an integrated regional resource planning approach for the region.

The East Lake Superior Region

The ELS region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south.

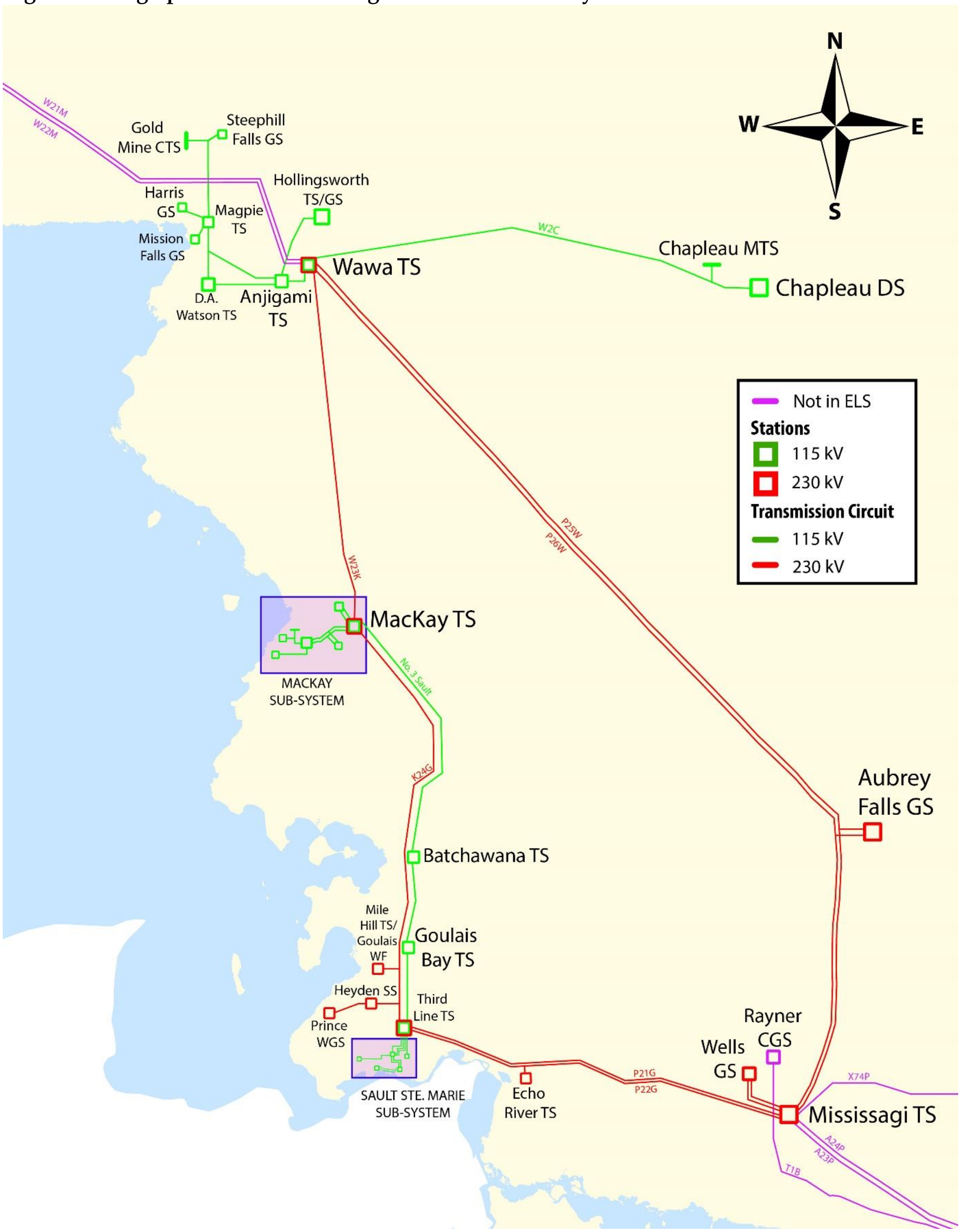
Electrical supply to the region is provided primarily through 230/115 kV autotransformers at Third Line TS, Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

The 230 kV transmission facilities in this area provide both bulk system and regional system functions. That is, in addition to delivering reliable supply to local customers, they also form part of an integrated network that enables the bulk transfer of electricity across the province. Although the bulk transmission system is not the focus of regional planning, it impacts how the system is modelled and studied.

The region has over 1,200 MW of generation, including numerous hydroelectric facilities, wind and solar farms and thermal generating facilities. The transmitters in the region are HOSSM and HONI; the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and SSM PUC.

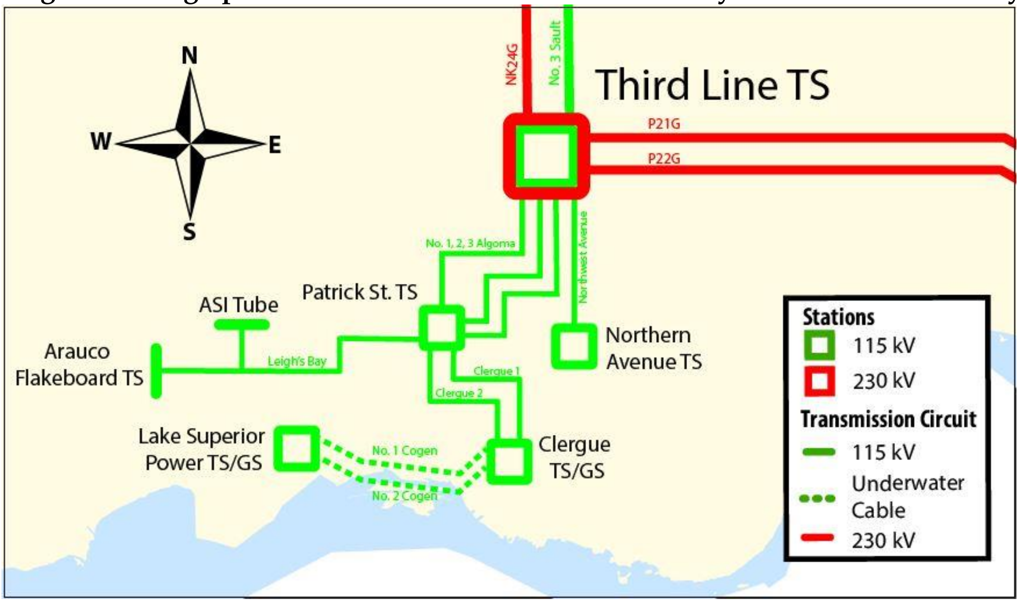
Geographic layouts of the electricity infrastructure supplying the region are shown in Figures 1, 2 and 3. An electrical single line diagram for the same area is shown in Figure 4.

Figure 1: Geographical Area of the Region with Electrical Layout



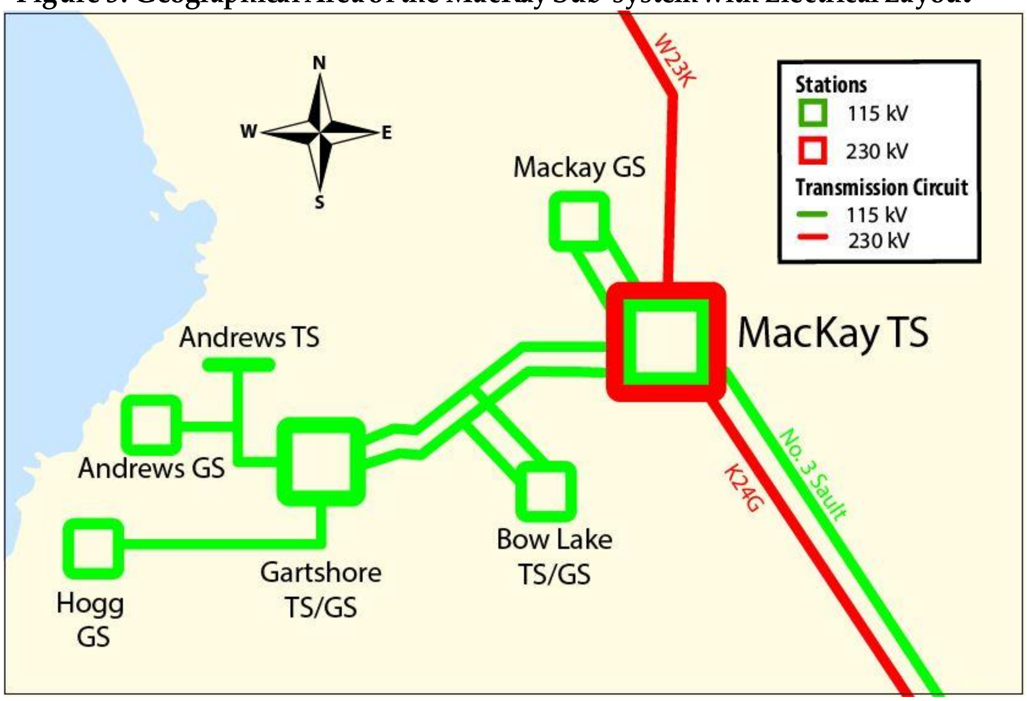
Source: IESO

Figure 2: Geographical Area of the Sault Ste. Marie Sub-system with Electrical Layout



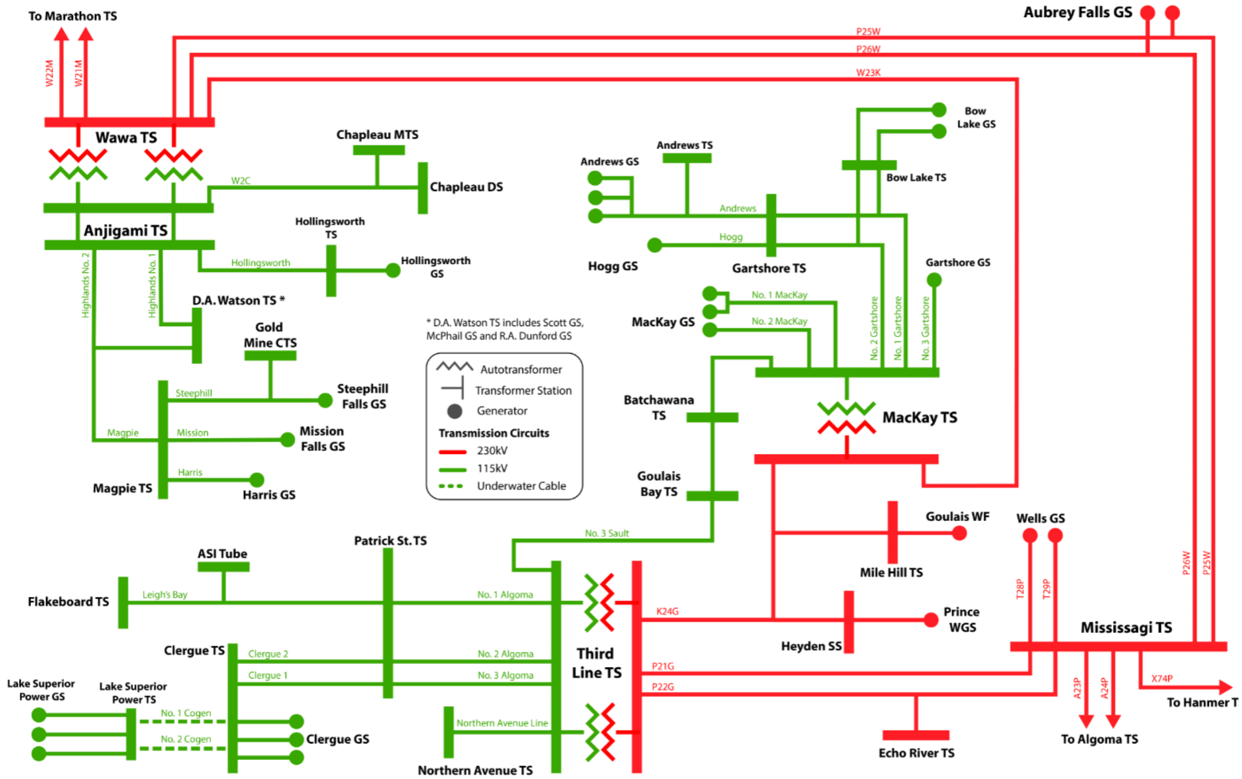
Source: IESO

Figure 3: Geographical Area of the MacKay Sub-system with Electrical Layout



Source: IESO

Figure 4: ELS Region Single Line Diagram



Source: IESO

Background

The first cycle of the ELS regional planning process was initiated by the former Great Lakes Power Transmission (GLPT) in October 2014 and completed in December 2014 with the publication of the 2014 NA report. That report identified a number of potential needs and recommended addressing them through the development of localized wires-only solutions – further coordinated regional planning did not proceed following its release.

In 2016, Hydro One acquired GLPT and renamed the company Hydro One Sault Ste. Marie LP. The second cycle of regional planning was kicked off by HOSSM in April 2019 and the NA report was published in June 2019. The needs identified in this report form the basis of the analysis for the Scoping Assessment and are discussed in further detail in Section 3 of the Scoping Assessment Report.

During the Scoping Assessment, the Study Team reviewed the nature and timing of known needs to determine both the most appropriate planning approach and the best geographic grouping of needs to create efficient study areas. The planning approaches considered include:

1. An IRRP – where a greater range of options, including non-wires, are to be considered as options and/or closer coordination with communities and stakeholders is required;

2. A RIP – which considers more straightforward wires-only options with limited engagement; or
3. A local plan undertaken by the transmitter and affected local distribution companies (LDCs) – where no further regional coordination is needed.

2. Objectives

The East Lake Superior IRRP will assess the adequacy of electricity supply to customers in the region and develop a set of recommendations to reliably maintain supply over the next 20 years. Specifically, the IRRP will:

- Assess the adequacy of electricity supply to customers in the ELS region over the next 20 years;
- Identify system reliability needs and develop and assess options to maintain system reliability;
- Determine whether there is a need to initiate development work or to fully commit infrastructure investments in this planning cycle;
- Identify and coordinate major asset renewal needs with regional needs, and develop a flexible, comprehensive, integrated electricity plan for East Lake Superior; and
- Develop an implementation plan with the flexibility to accommodate changes in key assumptions over time, while keeping options viable.

3. Scope

This IRRP will develop and recommend an integrated plan to meet region needs. The plan will be a joint initiative involving HOSSM, HONI, Algoma Power Inc., Hydro One Distribution, Sault Ste. Marie PUC and the IESO. These organizations will be defined as the Working Group for the ELS IRRP.

The plan will focus on:

- Third Line autotransformer overload need
- No.1 Algoma overload need
- Load security needs in the SSM PUC sub-system
- Unbundling of embedded generation
- Any additional needs that emerge in carrying out the IRRP

As with all IRRPs, the ELS IRRP will integrate forecast electricity demand growth, conservation and demand management (CDM); uptake of distributed energy resources (DERs); transmission and distribution system capability; relevant community plans; and bulk system developments as applicable. The IRRP will be carried out in a manner that allows for continuous coordination of information with other planning activities and processes.

The ELS IRRP process will involve:

1. Development of a stakeholder engagement plan.
2. Creation of an updated 20-year demand/load forecast for the region.

3. Assessment of the adequacy and reliability of the transmission system against established criteria and determination of the area's load meeting capability.
    a. Identify or confirm the system needs and adequacy of the area's load meeting capability for the study period using the updated load forecast.
    b. Confirm identified restoration and security needs using the updated load forecast.
    c. Collect information on any known reliability issues and load transfer capabilities from LDCs.
4. Development and assessment of options to mitigate identified needs. Options are evaluated using decision-making criteria, including but not limited to technical feasibility, economics, reliability performance, and environmental and social factors.
5. Development of the long-term recommendations and the implementation plan.
6. Completion of the IRRP report documenting near-, mid-, and long-term needs and recommendations.

Depending on the nature and the urgency of the electricity needs and risks identified, the IRRP could recommend a combination of the following:

- Active monitoring of load growth and equipment performance;
- Project development work to shorten lead times, without firm commitment for constructing the project;
- Commitment of project and proceed with project implementation (e.g., resources acquisition, transmission procurement, regulatory approval);
- Interim measures to manage near-term requirements, pending implantation of longer-term solutions;
- Pilots, studies and/or engagement to gather more information; and
- Coordination with other planning or related processes (e.g., community or bulk system planning).

Should the need for infrastructure investment be identified, the IRRP will provide a rationale and define high-level requirements to support project development and implementation to be carried out by other proponents. The outcomes from the ELS IRRP will help inform transmitter and LDC rate filings and any related transmission/resource acquisition processes that may result.

It is important to note that detailed discussion of acquisition mechanisms, cost allocation, cost recovery, siting, operations and implementation of recommended projects are beyond the scope of an IRRP.

In order to carry out this scope of work, the working group will consider the data and assumptions outlined in section 4.

4. Data and Assumptions

The plan may consider the following data and assumptions, where applicable:

- Demand data

    - Historical coincident and non-coincident peak demand information for the region
    - Impact of embedded generation on historic grid demand
    - Historical weather correction, for median and extreme conditions
    - Gross peak demand forecast scenarios, e.g., by region, sub-system, TS
    - Coincident peak demand data, including transmission-connected customers
    - Potential future load customers
- Conservation and demand management
    - Long-term conservation forecast for LDC customers based on planned provincial CDM activities
    - LDC programs, if applicable
    - Conservation potential studies, if available
- Local resources
    - Existing local generation, including distributed generation, district energy, customer-based generation, non-utility generators and hydroelectric facilities as applicable
    - Existing or committed renewable generation from Feed-in-Tariff (FIT) and non-FIT procurements
    - Future resource proposals as relevant
- Relevant local plans, as applicable
    - LDC distribution system plans
    - Community energy plans and municipal energy plans (e.g., Community Energy Investment Strategy for Waterloo Region)
    - Municipal growth plans
- Criteria, codes and other requirements
    - ORTAC
    - NERC and NPCC reliability criteria, as applicable
    - OEB Transmission System Code
    - OEB Distribution System Code
    - Other applicable requirements
- Existing system capability
    - Transmission line ratings as per transmitter records
    - Transformer ratings as per asset owner(s)
    - Load transfer capabilities
    - Technical and operating characteristics of local generation
- End-of-life asset considerations and sustainment plans
    - Transmission assets
    - Distribution assets
    - Impact of ongoing plans and projects on applicable facility ratings
- Other considerations, as applicable

5. Working Group

The core Working Group will consist of planning representatives from the following organizations:

- Independent Electricity System Operator *(Team Lead for IRRP)*
- Hydro One Sault Ste. Marie LP
- Hydro One Networks Inc.
- Algoma Power Inc.
- Hydro One Distribution
- Sault Ste. Marie PUC

<u>Authority and Funding</u>

Each organization involved in the study will be responsible for complying with any regulatory requirements applicable to the actions/tasks assigned to it under the implementation plan resulting from this IRRP. For the duration of the study process, each participant is responsible for their own funding.

5. Engagement

Integrating early and sustained engagement with communities and stakeholders is a key component of the IRRP planning process.

The first step in engagement will consist of the development of a stakeholder engagement plan, which will be made available for comment before it is finalized. The scope of community and stakeholder engagement to be considered for this IRRP may include:

- Local electricity needs and considerations
- Status and key assumptions from community energy planning (e.g., energy intensity, electric vehicles and fuel switching scenarios)
- Status and key assumptions in growth plans and local economic developments (e.g., housing, population growth, commercial and industrial development)
- Impact of climate change in the East Lake Superior region
- Long-term land use and Infrastructure corridor plans
- Local interest in developing and implementing community-based energy solutions and factors that could facilitate or hinder the implementation of community-based energy solutions (e.g., existing or planned pilot projects, and the availability of local funding to support them; local policy/programs that enable/hinder project development; support from local utilities, community groups and government; and land use impacts and considerations.

6. Activities, Timeline and Primary Accountability

Table A-1: Summary of Expected IRRP Timelines and Activities

Activity		Lead Responsibility	Deliverable(s)	Approximate Time frame
1	**Prepare Terms of Reference considering stakeholder input**	*IESO*	- Finalized Terms of Reference	July - Oct 2019
2	**Develop the Planning Forecast for the sub-region**			
	Establish historical coincident and non-coincident peak demand information	*IESO*	- Long-term planning forecast scenarios	Oct 2019 – Jan 2020
	Establish historical weather correction, median and extreme conditions	*IESO*		
	Establish gross peak demand forecast and growth scenarios	*LDCs*		
	Establish existing, committed and potential distributed generation	*LDCs*		
	Establish near- and long-term conservation forecasts based on planned energy-efficiency activities and codes and standards	*IESO*		
	Develop planning forecast scenarios - including the impacts of CDM, DG and extreme weather conditions	*IESO*		
3	**Provide information on load transfer capabilities under normal and emergency conditions**	*LDCs*	- Load transfer capabilities under normal and emergency conditions	Oct 2019 – Jan 2020
4	**Provide and review relevant community plans, if applicable**	*LDCs and IESO*	- Relevant community plans	Oct 2019 – Jan 2020

	Activity	Lead Responsibility	Deliverable(s)	Approximate Time frame
5	**Complete system studies to identify needs over a 20-year period** - Develop PSS/E base cases, including bulk system configuration and connectivity assumptions as identified in the key assumptions - Apply reliability criteria – as defined by NERC and NPCC and described in ORTAC – to demand forecast scenarios - Confirm and refine the need(s) and timing/magnitude	*IESO*	- Summary of needs based on demand forecast scenarios for the 20-year planning horizon	Q1 – Q2 2020
6	**Develop Options and Alternatives**			
	Develop conservation options, where applicable	*IESO and LDCs*	- Develop flexible planning options for forecast scenarios	Q2 – Q3 2020
	Develop local generation options, where applicable	*IESO and LDCs*		
	Develop transmission (see Action 7 below) and distribution options, where applicable	*All*		
	Develop options involving other electricity initiatives, where applicable (e.g., smart grid, storage)	*IESO/ LDCs with support as needed*		
	Integrate with bulk needs	*IESO*		
	Develop portfolios of integrated alternatives, where applicable	*All*		
	Technical comparison and evaluation	*All*		
7	**Plan and Undertake Community & Stakeholder Engagement**			
	Early engagement with local municipalities and Indigenous communities within study area, First Nation communities who may have an interest in the study area, and the Métis Nation of Ontario	*All*	- Community and stakeholder engagement plan - Input from local communities	Q3 2020
	Develop communications materials	*All*		ongoing
	Undertake community and stakeholder engagement	*All*		
	Summarize input and incorporate feedback	*All*		

Activity		Lead Responsibility	Deliverable(s)	Approximate Time frame
8	**Develop long-term recommendations and implementation plan based on community and stakeholder input**	*IESO*	- Implementation plan - Monitoring activities and identification of decision triggers - Hand-off letters - Procedures for annual review	Q3-Q4 2020
9	**Prepare the IRRP report detailing the recommended near-, medium- and long-term plan for approval by all parties**	*IESO*	- IRRP report	March 31 2021

Appendix B: Selecting a Regional Planning Approach

Needs identified through the NA process will be reviewed during the Scoping Assessment to determine whether a Local Plan (LP), Regional Infrastructure Plan (RIP), or Integrated Regional Resource Plan (IRRP) is more appropriate. Where multiple sub-regions are identified, each will be considered individually. A combination of LP, RIP and IRRP planning approaches could be selected in different sub-regions, although an urgent need for wires-type solution will typically trigger a hand-off letter instead.

Each of the three potential planning outcomes has different functions, and selection should be made based on a region's unique needs and circumstances. The criteria used to select the regional planning approach within each sub-region are consistent with the principles laid out in the PPWG Report to the Board,[5] and are discussed in this document to ensure consistency and efficiency throughout the Scoping Assessment.

IRRPs are comprehensive undertakings that consider a wide range of potential solutions, including conservation, generation, new technologies and wires infrastructure, to determine the optimal mix of resources to meet region needs over a 20-year time frame. RIPs are narrower in scope, focusing instead on identifying and assessing specific wires alternatives and recommending the preferred wires solution. In limiting the extent of its consideration to wires solutions that do not require further coordinated planning, LPs have the narrowest scope. An LP process is recommended when needs:

a) Are local in nature (only affecting one LDC or customer)
b) Involve limited investments of wires (transmission or distribution) solutions
c) Do not require upstream transmission investments
d) Do not require plan level community and/or stakeholder engagement and
e) Do not require other approvals such as an OEB Leave to Construct (S92) application or Environmental Approvals.

If coordinated planning is required to address identified needs, either an RIP or IRRP may be initiated. A series of criteria have been developed to assist in determining which planning approach is the most appropriate based on identified needs. In general, an IRRP is initiated when:

[5] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

- A non-wires measure has the potential to meet or significantly defer the needs identified by the transmitter during the NA;
- Community or stakeholder engagement is required; or
- The planning process or outcome has the potential to impact bulk system facilities.

If the only feasible measures involve new/upgraded transmission and/or distribution infrastructure, with no requirement for engagement or anticipated impact on bulk systems, an RIP will be selected instead.

Wires-type transmission/distribution infrastructure solutions refer, but are not limited to:

- Transmission lines
- Transformer/switching stations
- Sectionalizing devices, including breakers and switches
- Reactors or compensators
- Distribution system assets

Determining the feasibility of non-wires alternatives to meet identified needs should also consider issues such as timelines for implementing solutions. For instance, if a need has been identified as immediate or near-term, non-wires solutions that rely on lengthy development and roll-out periods may not be feasible.

Appendix D

East Lake Superior Region Integrated Regional Resource Plan

Integrated Regional Resource Plan

East Lake Superior Region
April 2021

Connecting Today.
Powering Tomorrow.

Table of Contents

List of Figures

List of Tables

List of Appendices

List of Acronyms

BKF	Breaker Failure
CDM	Conservation and Demand Management
DG	Distributed Generation
ELS	East Lake Superior
EWT	East West Transfer
EWTE	East West Transfer East
EWTW	East West Transfer West
GLPT	Great Lakes Power Transmission
HONI	Hydro One Networks Inc.
HOSSM	Hydro One Sault Ste. Marie LP
IESO	Independent Electricity System Operator
IRRP	Independent Electricity Regional Resource Plan
kV	Kilovolt
LDC	Local Distribution Company
LMC	Load Meeting Capability
LTR	Limited Time Rating
MW	Megawatt
NERC	North American Electric Reliability Corporation
NUG	Non-Utility Generator
NA	Needs Assessment
NPCC	Northeast Power Coordinating Council
OEB	Ontario Energy Board

ORTAC	Ontario Resource and Transmission Assessment Criteria
RIP	Regional Infrastructure Plan
SIA	System Impact Assessment
STE	Short Term Emergency
TS	Transformer Station
TTC	Total Transfer Capability

Integrated Regional Resource Plan
ELS

This Integrated Regional Resource Plan (IRRP) was prepared by the Independent Electricity System Operator (IESO) pursuant to the terms of its Ontario Energy Board licence, EI-2013-0066.

This IRRP was prepared on behalf of the East Lake Superior (ELS) Region Technical Working Group which included the following members:

- Independent Electricity System Operator
- PUC Distribution Inc.
- Algoma Power Inc.
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- Hydro One Sault Ste. Marie LP

The Technical Working Group assessed the reliability of electricity supply to customers in the ELS region over a 20-year period beginning in 2020 and developed an implementation plan for the recommended options, while maintaining flexibility in order to accommodate changes in key conditions over time and align with IESO's bulk planning study for the broader region commencing in 2021.

The ELS Technical Working Group members agree with the IRRP's recommendations and support implementation of the plan, subject to obtaining necessary regulatory approvals and appropriate community consultations as required.

The ELS region Technical Working Group members do not commit to any capital expenditures and must still obtain all necessary regulatory and other approvals to implement recommended actions.

This report is organized as follows:

- The plan is introduced in Section 1;
- A summary of the recommended plan for the ELS Region is provided in Section 2;
- The process and methodology used to develop the plan are discussed in Section 3;
- The context for electricity planning in the ELS Region and the study scope are discussed in Section 4;
- Demand forecast, conservation and distributed generation assumptions are described in Section 5;
- Electricity needs in the ELS Region are presented in Section 6;
- Options and recommendations for meeting needs are addressed in Section 7;
- A summary of engagement to date and moving forward is provided in Section 8;
- A conclusion is provided in Section 9.

1. Introduction

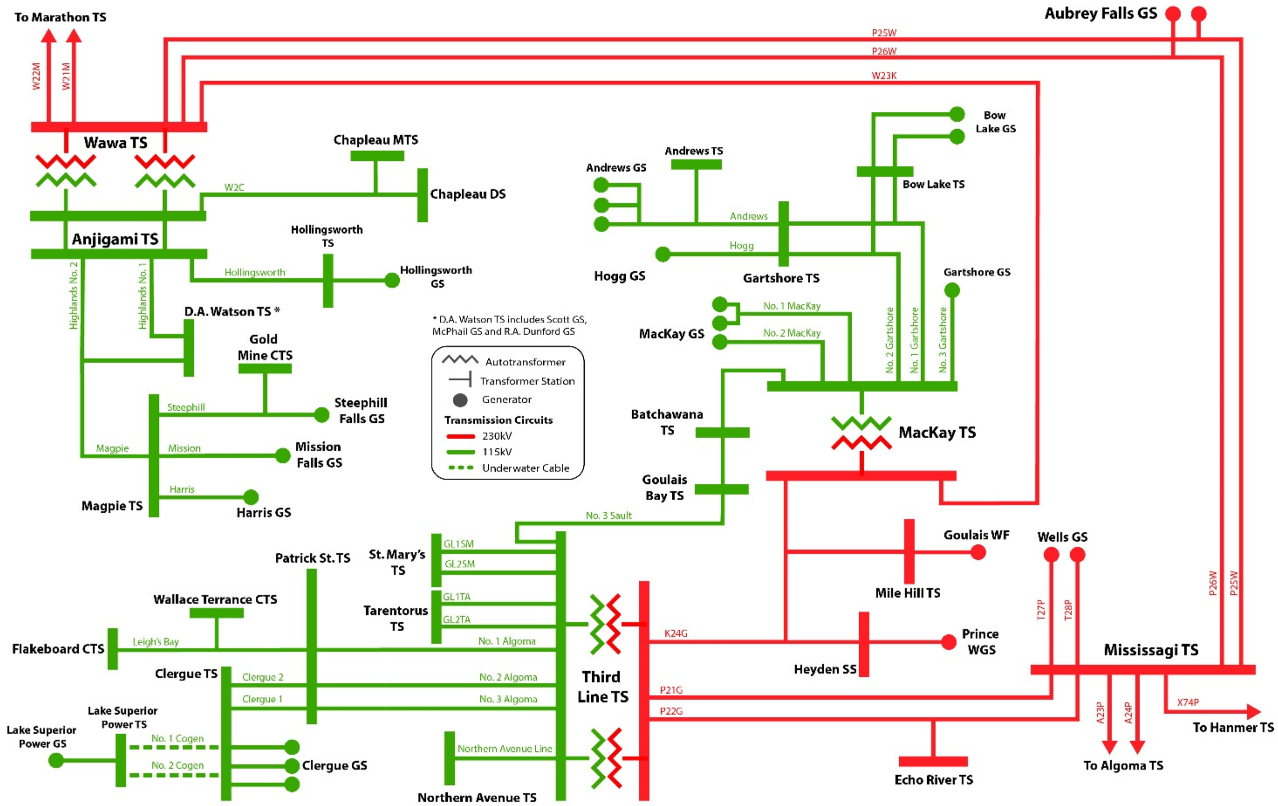
This IRRP for the ELS region addresses the regional electricity needs over the study period, i.e., from 2020 to 2040. This IRRP report was prepared by the Independent Electricity System Operator (IESO) on behalf of the Technical Working Group composed of IESO, PUC Distribution Inc., Algoma Power Inc., Hydro One Networks Inc. (Distribution), Hydro One Networks Inc. (Transmission) and Hydro One Sault Ste. Marie LP.[1]

In Ontario, planning to meet the electrical reliability needs of a large area or region is carried out through regional electricity planning, a process that was formalized by the Ontario Energy Board (OEB) in 2013. In accordance with this process, transmitters, distributors and the IESO are required to carry out regional planning activities for the 21 electricity planning regions across Ontario, including the ELS region, at least once every five years.

In this region, the electrical load is comprised of industrial, commercial and residential users and is winter peaking. The ELS region is supplied through 230/115 kV autotransformers at Third Line Transformer Station (TS), Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figure 1. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

[1] Hydro One Distribution participated on behalf of Chapleau PUC

Figure 1 | ELS Single Line Diagram



2. The Integrated Regional Resource Plan

This IRRP provides recommendations to address the electricity needs of the ELS region over the next 20 years. The needs identified are based on the demand growth anticipated in the region and the capability of the existing transmission system as evaluated through application of the IESO's Ontario Resource and Transmission Assessment Criteria (ORTAC) and reliability standards governed by North American Electric Reliability Corporation (NERC). The IRRP's recommendations are informed by an evaluation of options, representing alternative ways to meet the needs, that considers: reliability, cost, technical feasibility, maximizing the use of the existing electricity system (where economic), and feedback from stakeholders.

While the demand forecast underpinning this plan is relatively flat over the 20-year planning horizon, there is potential for significant growth in industrial loads directly connected to the high voltage transmission system which can impact the bulk transmission system in the broader region. Accordingly, this high industrial growth is not included in this plan and will be studied as part of the IESO's bulk planning study, starting in 2021.

While the bulk planning study will consider high industrial growth, some of the needs identified as part of this IRRP are linked to the bulk transmission system in the broader region and should thus be considered as part of this study to ensure a coordinated approach. As such, this IRRP has identified the needs for which this coordination is required and has recommended that they be carried forward into the IESO's bulk planning study. For those needs that are not directly linked to the bulk transmission system in the broader region, this IRRP has identified specific recommendations to address them.

2.1 Recommendations of the Plan

The recommended actions to address the region's needs are summarized in Table 2.1 below, together with the details of their implementation.

Table 2.1 | Implementation of Recommended Plan for ELS Region

Need	Recommendation	Lead Responsibility	Required By
Loss of one Third Line TS autotransformer causes the companion autotransformer to be loaded close to its capacity	Monitor load and supply in the ELS region	IESO/HOSSM	Immediately and Ongoing

Need	Recommendation	Lead Responsibility	Required By
Loss of P21G and P22G circuits causes voltage collapse at Third Line TS and other ELS stations	Enable remote arming of GLP Instantaneous Load Rejection Scheme for P21G and P22G double contingency for operational efficiency over manual arming	Hydro One	Immediately
Loss of two Algoma circuits or a Patrick St TS 214 BKF results in thermal overload of the remaining Algoma circuit	Implement automatic load rejection scheme at Patrick St TS	HOSSM	Immediately
During an outage of P25W or P26W circuits, a loss of the K24G circuit results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
During an outage of one of the Third Line TS autotransformers, a loss of the companion autotransformer results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa	Hydro One to work with the LDC to build a new 115/44 kV station that will tap off Hollingsworth 115 kV circuit to accommodate the load increase	HOSSM	2024

3. Development of the Plan

3.1 The Regional Planning Process

In Ontario, preparing to meet the electricity needs of customers at a regional level is achieved through regional planning. Regional planning assesses the interrelated needs of a region defined by common electricity supply infrastructure over the near, medium, and long term and results in a plan to ensure cost-effective and reliable electricity supply. A regional plan considers the existing electricity infrastructure in an area, forecast growth and customer reliability, develops and evaluates options for addressing needs, and recommends actions.

The current regional planning process was formalized by the OEB in 2013 and is performed on a five-year planning cycle for each of the 21 planning regions in the province. The process is carried out by the IESO, in collaboration with the transmitter(s) and LDC(s) in each planning region.

The process consists of four main components:

- A Needs Assessment, led by the transmitter, which completes an initial screening of a region's electricity needs and determines if there are electricity needs requiring regional coordination;
- A Scoping Assessment, led by the IESO, which identifies the appropriate planning approach for the identified needs and the scope of any recommended planning activities;
- An IRRP, led by the IESO, which proposes recommendations to meet the identified needs requiring coordinated planning; and/or
- A RIP, led by the transmitter, which provides further details on recommended wires solutions.

Regional Planning is one type of electricity planning in Ontario; other types include Bulk System Planning and Distribution System Planning (local planning). A key benefit of the regional planning process is that it provides an opportunity for the entities leading these various planning activities to develop efficient planning outcomes when considering the needs and alternatives as a whole.

Further details on the regional planning process and the IESO's approach to regional planning can be found in Appendix A.

The IESO has also finalized a review of the Regional Planning Process to consider lessons learned and findings from the previous cycle of regional planning and other regional planning development initiatives, such as pilots and studies. The recommendations and next steps from this review are available in the Regional Planning Process Review Final Report which is published on the IESO's website.

3.2 IESO's approach to Regional Planning

In assessing electricity system needs for a region over a 20-year period, IRRPs enable near-term actions to be developed in the context of a longer-term view of trends. This enables coordination and consistency with the long-term plan.

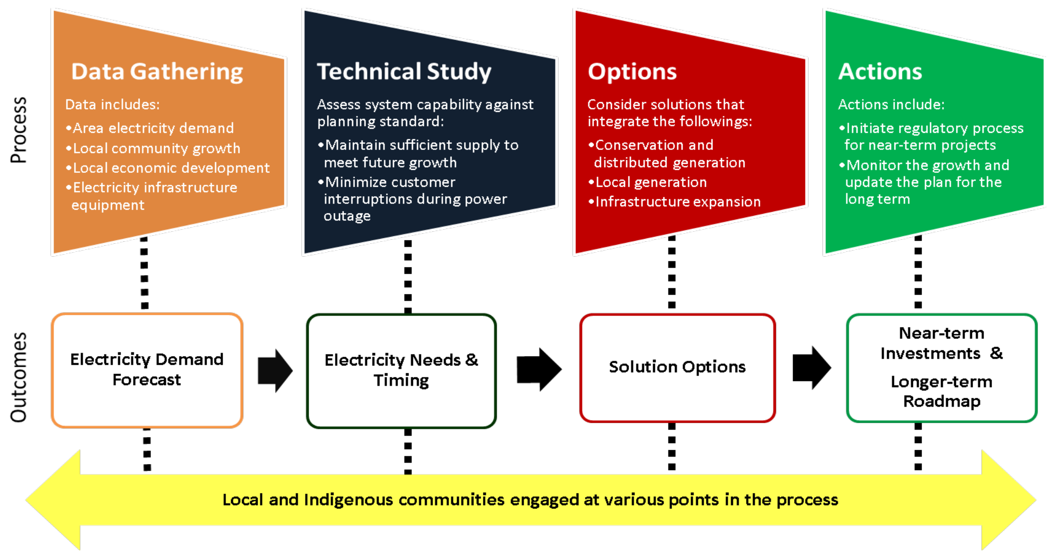
In developing this IRRP, the Technical Working Group followed a number of steps (See Figure 3.2) including:

- Data gathering, including development of electricity demand forecasts;
- Conducting technical studies to determine electricity needs and the timing of these needs;
- Developing and evaluating potential options; and
- Preparing a recommended plan including actions for the near and longer term.

Throughout this process, engagement was carried out with stakeholders with an interest in the area.

The IRRP documents the inputs, findings and recommendations developed through the process described above and provides recommended actions for the various entities responsible for plan implementation. The IRRP helps ensure that recommendations to address near-term needs are implemented, while maintaining the flexibility to accommodate changing long-term conditions.

Figure 3.2 | Steps in the IRRP Process



3.3 ELS Technical Working Group and IRRP Development

The second cycle of regional planning in ELS was initiated in April 2019. In June 2019, Hydro One published the Needs Assessment report for the region which included input from the IESO, Algoma Power, Chapleau PUC, Hydro One Distribution, Hydro One Sault Ste. Marie and PUC Distribution Inc. The Needs Assessment report identified needs which required coordinated regional planning and, therefore, the IESO conducted a Scoping Assessment process and issued the Scoping Assessment Outcome Report in October 2019. This report ultimately recommended that an IRRP be conducted for the region to assess the needs requiring a coordinated regional approach.

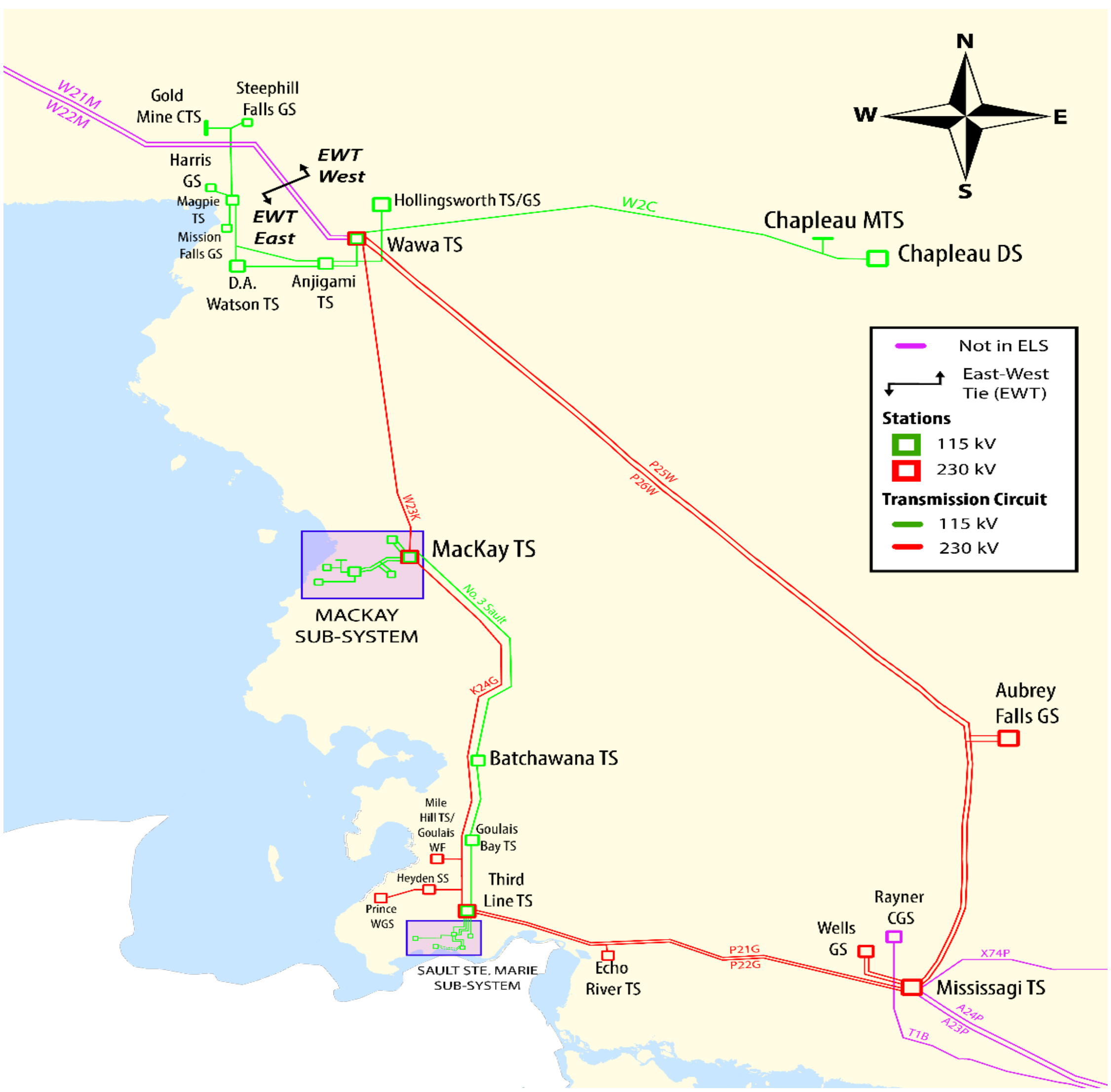
The Technical Working Group then gathered data, performed technical studies to identify the region's reliability needs, evaluated options to address the needs and developed the recommended actions included in this IRRP.

4. Background and Study Scope

In geographical terms, the region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south as shown in Figure 4.1 below.

The region is supplied from a combination of local generation and connection to the Ontario electricity grid via a network of 230 kV and 115 kV transmission lines and stations. The transmitters in the region are Hydro One Sault Ste. Marie LP (HOSSM) and Hydro One Networks Inc. (Hydro One); the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and PUC Distribution Inc.

Figure 4.1 | ELS Transmission System



4.1 History of Electricity Planning in the ELS Region

This is the second cycle of regional planning for the ELS region. In the first cycle, a Needs Assessment was completed by Hydro One in late 2014 which did not identify electricity needs in the next 10 years requiring regional coordination. The Needs Assessment report identified issues for which local wires only solutions were to be developed.

4.2 Study Scope

This IRRP was prepared by the IESO on behalf of the Technical Working Group and recommends options to meet the electricity needs of the ELS region of the study period with a focus on providing an adequate, reliable supply to support community growth. The objectives and scope of this IRRP are set out in the Scoping Assessment, together with the roles and responsibilities of the Technical Working Group members.

The transmission facilities in-scope of the ELS IRRP are described below:

- 230/115 kV autotransformers- Third Line TS, Wawa TS, Mackay TS;
- 230 kV connected stations- Mississagi TS, Echo River TS, Heyden CSS, Mile Hill CTS;
- 115 kV connected stations- Anjigami TS, Chapleau MTS, Chapleau DS, Hollingsworth TS, DA Watson TS, Magpie TS, Gold Mine CTS, Flakeboard CTS, Wallace Terrance CTS, Patrick St TS, Lake Superior Power TS, Clergue TS, Northern Avenue TS, Goulais Bay TS, Batchawana TS, Gartshore TS, Andrews TS and Bow Lake TS, St. Mary's MTS, Tarentorus MTS;
- 230 kV transmission lines – P25W, P26W, W23K, K24G, P21G, P22G, T28P, T27P;
- 115 kV transmission lines – W2C, High Falls No. 1. High Falls No. 2, Magpie, Harris, Mission, Steephill, Andrews, Hogg, No. 1 Mackay, No. 2 Mackay, No. 1 Gartshore, No. 2 Gartshore, No. 3 Gartshore, Sault No.3, No. 1 Algoma, No. 2 Algoma, No. 3 Algoma, Clergue 1, Clergue 2, Leigh's Bay, No. 1 Cogen, No. 2 Cogen, GL1SM, GL2SM, GL1TA, GL2TA;
- 115 kV generation assets – Hollingsworth GS, Harris GS, Mission Falls GS, Steephill Falls GS, Andrews GS, Bow Lake GS, Hogg GS, Gartshore GS, Mackay GS, Clergue GS, Lake Superior CGS;
- 230 kV generation assets – Aubrey Falls GS, Wells GS; and
- Storage – Sault Ste. Marie Energy Storage at St. Mary's MTS.

The ELS IRRP was developed by completing the following steps:

- Preparing a 20-year electricity demand forecast and establishing needs over this timeframe;
- Examining the Load Meeting Capability ("LMC") and reliability of the existing transmission system, taking into account facility ratings and performance of transmission elements, transformers, local generation, and other facilities such as reactive power devices. Needs were established by applying NERC standards and ORTAC;
- Assessing system needs by applying a contingency-based assessment and reliability performance standards for transmission supply in the IESO-controlled grid as described in Section 7 of ORTAC;

- Confirming identified end-of-life asset replacement needs and timing with HOSSM and Hydro One;
- Establishing alternatives to address system needs, including, where feasible and applicable, possible energy efficiency, generation, transmission and/or distribution, and other approaches such as Non-Wires Alternatives;
- Engaging with the community on needs, findings, and possible alternatives;
- Evaluating alternatives to address near and long-term needs; and
- Communicating findings, conclusions, and recommendations within a detailed plan.

4.2 IESO’s Bulk Planning Study

While the demand forecast underpinning this plan is relatively flat over the 20-year planning horizon, there is potential for significant growth in industrial loads directly connected to the high voltage transmission system which can impact the bulk transmission system in the broader region. Accordingly, this high industrial growth is not included in this plan and will be studied as part of the IESO’s bulk planning study, starting in 2021.

While the bulk planning study will consider high industrial growth, some of the needs identified as part of this IRRP are linked to the bulk transmission system in the broader region and should thus be considered as part of this study to ensure a coordinated approach. As such, this IRRP has identified the needs for which this coordination is required and has recommended that they be carried forward into the IESO’s bulk planning study. For those needs that are not directly linked to the bulk transmission system in the broader region, this IRRP has identified specific recommendations to address them.

5. Electricity Demand Forecast

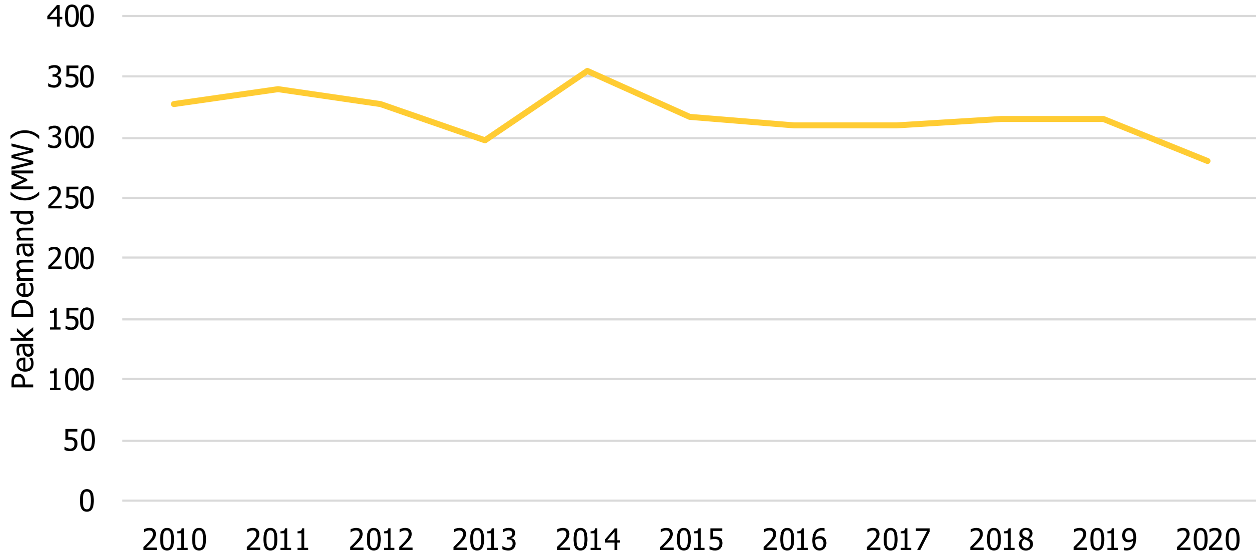
A fundamental consideration in any electricity supply study is how much electricity will be required in the region over the study period. This section describes the development of the demand forecast within the ELS Region over the 20-year study period, highlighting the assumptions made for peak demand load forecasts (i.e., the maximum demand in MW forecasted to occur in each year), including the expected contribution of conservation and demand management, and Distributed Generation (DG) to reducing peak demand. When combined, these factors produce the net peak demand forecast used to assess the electricity needs of the area over the planning horizon.

To evaluate the reliability of the electricity system, regional planning is typically concerned with the coincident peak demand for a given area, or the demand observed at each station for the hour of the year in which overall demand in the study area is at a maximum. This represents the moment when assets are at their most stressed, and resources generally the most constrained. This differs from a non-coincident peak, which is the sum of individual peaks at each station, regardless of whether these peaks occur at different times.

Within the ELS region, the peak loading hour for each year typically occurs in the evening in the winter season and is driven by electrical heating demand in the residential sector as access to natural gas is limited in the area. In addition, the region is home to a number of large industrial customers, in the manufacturing and mining sectors, that consume large amounts of energy (i.e., the total amount of electricity flowing through the system over time and typically measured in MWh) over the course of a year. Energy consumption by these customers can be impacted by economic conditions, such as commodity prices. Due to the large number of industrial customers in the region whose peaks do not coincide with the residential customers, this plan assumed non-coincident peak load at each station except for the two transformer stations owned by PUC Distribution Inc. since they have the ability to transfer loads between their two stations.

Historical winter peak demand in the region has decreased from 355 MW in 2014 to 280 MW in 2020. This decline is primarily due to the closure of large industrial customers in the pulp and paper sector. COVID-19 is also expected to have contributed to the decline observed in 2020. Figure 5.0 shows the historical winter peak demand in the ELS region.

Figure 5.0 | Historical Peak Demand in the ELS Region (2010-2020)



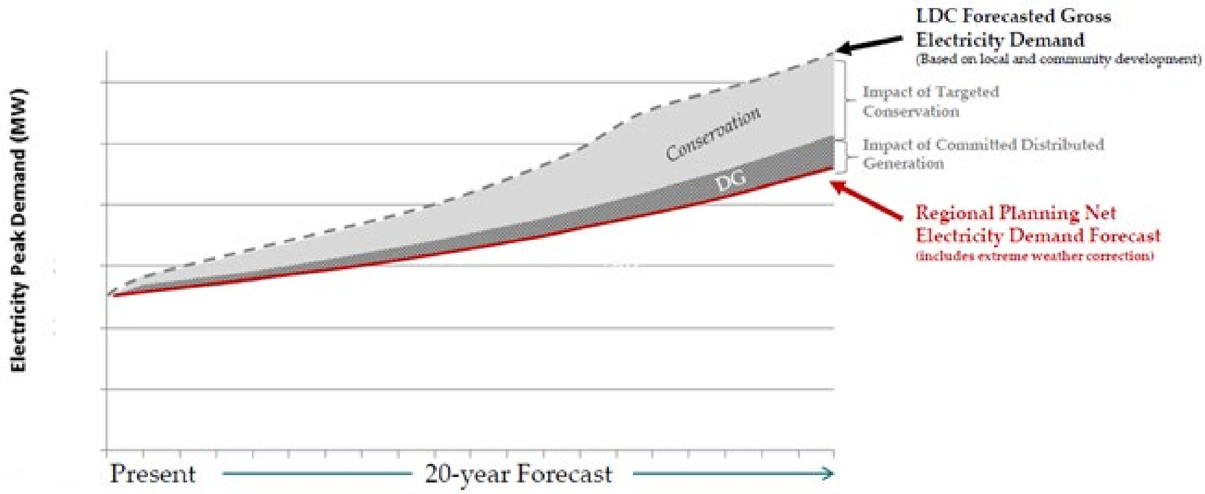
5.1 Methodology for Preparing the Forecast

A 20-year non-coincident peak demand forecast was developed for the region to assess its reliability needs. The steps taken to develop this forecast are illustratively shown in Figure 5.2 and described below.

1. The IESO weather-corrected the most recent year's demand data (2018 at the time of forecast development) to create a forecast "start" point based on expected peak demand under median (or "most likely") weather conditions. This "start" point was provided to the LDCs to help inform the basis of their forecasts.
2. Each participating LDC developed its own 20-year demand forecast for each station in their service areas. Since LDCs have the closet relationship to customers, connection applicants, and municipalities and communities, they have a better understanding of future local load growth and drivers than the IESO. The IESO typically carries out load forecasting at the provincial level.
3. The IESO modified the LDC forecasts provided for each station to reflect extreme weather conditions and subtracted the estimated peak demand impacts of provincial conservation policy and committed DERs that may have been contracted through previous provincial programs such as the Feed-in Tariff (FIT) and microFIT programs.

The result of these steps was a station-by-station outlook of net annual peak demand over the study period. Additional details on the demand forecast process, including station-level forecasts, may be found in Appendix B.

Figure 5.1 | Illustrative Development of Net Demand Forecasts



5.1.1 Conservation Assumptions in the Forecast

Conservation is achieved through a mix of program-related activities and mandated efficiencies from building codes and equipment standards. Future CDM savings for the ELS Region have been applied to the peak gross demand forecast and take into account both policy-driven and funded EE through the provincial Interim Framework, which came into effect on April 1, 2019 (estimated peak demand impacts due to program delivery to the end of 2020). The Interim Framework has targets to achieve annual energy savings of 1.4 TWh and peak demand reductions of 189 MW.[2] Expected peak demand impacts due to building codes and equipment standards were also included for the duration of the forecast.

Once sectoral gross forecast demand at each TS was estimated, peak-demand savings were estimated for each conservation category – building codes and equipment standards, and delivery of funded CDM programs. Due to the unique characteristics and available data associated with each category, estimated savings were determined separately. The total conservation savings included in the net demand forecast are provided in Table 5.1.1 below. These savings are broken down by residential, commercial and industrial customer sectors.

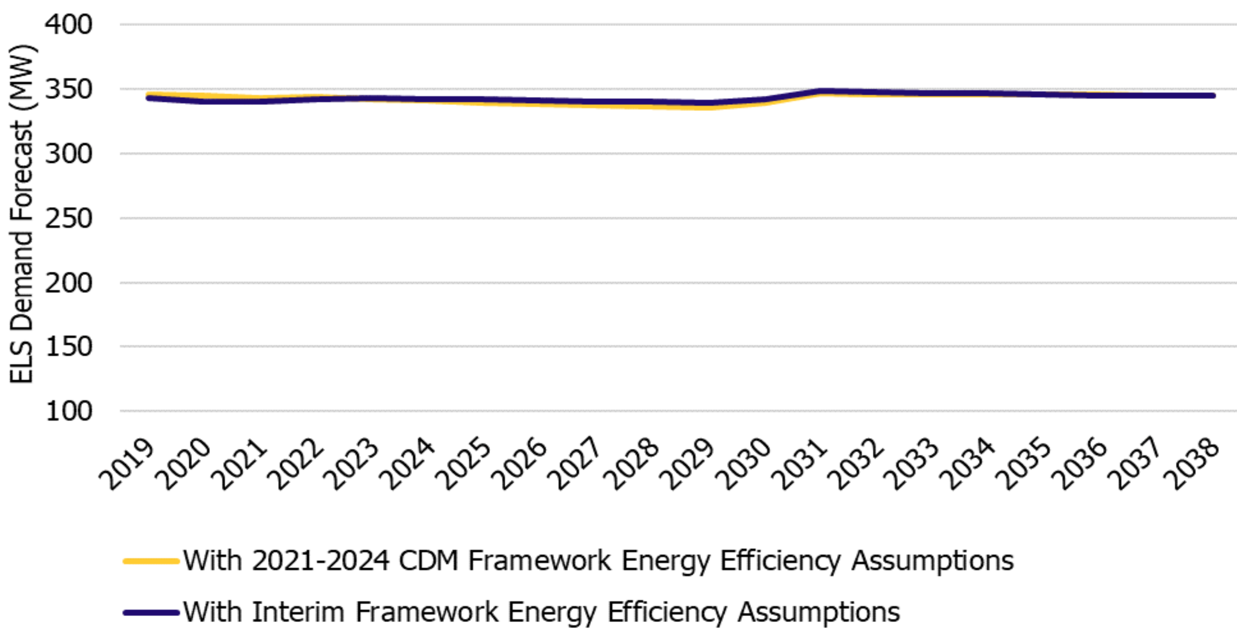
Table 5.1.1 | Peak Demand Savings due to Codes and Standards and Funded CDM Programs (MW)

Year	2020	2025	2030	2038
Residential	0.6	0.9	2.7	5.3
Commercial	3.8	2.4	1.1	0.4
Industrial	0.0	0.0	0.0	0.0
Total	4.5	3.3	3.8	5.7

[2] https://www.ieso.ca/en/Sector-Participants/Energy-Efficiency/2021-2024-Conservation-and-Demand-Management-Framework

After the demand forecast was developed for the ELS IRRP, the new 2021-2024 CDM framework starting in January 2021 was announced. While the Interim Framework assumptions were used in the development of the planning forecast, a sensitivity using the assumptions of the 2021-2024 CDM Framework was conducted. This sensitivity showed minimum impact (less than 2% difference) to the region's demand forecast as shown in Figure 5.1.1.

Figure 5.1.1 | Comparison of Planning Demand Forecast with Interim Framework Energy Efficiency Assumptions vs 2021-2024 CDM Framework Energy Efficiency Assumptions



5.1.2 Distributed Energy Resources Assumptions in the Forecast

After applying the conservation savings to the gross demand forecast as described above, the forecast is further reduced by the expected peak contribution of existing and contracted DERs in the area. The peak demand impact of DERs that were connected to the system at the time of forecast development were accounted for in the IRRP. Given the difficulty of predicting future DER uptake, no assumptions have been made regarding future DER growth.

While the FIT Program and other procurements for small-scale generation have ended, the IESO remains committed to transitioning to the long-term use of competitive mechanisms to meet Ontario's resource adequacy needs through the Resource Adequacy Framework. In addition, the IESO is engaged in several activities to help reduce the barriers to DERs as alternatives to wires-based solutions. Additional details of these activities are included in the IESO's Regional Planning Process Review Report.

Based on the IESO contract list as of March, 2019, DERs in the ELS region are expected to offset demand by 14.6 MW of winter effective capacity at the start of the study period. As the DER contracts expire over the planning period, their contribution is removed accordingly. The DERs included in this IRRP are distribution connected from the following stations:

- Echo River TS
- Batchawana TS
- Goulais Bay TS
- Patrick St TS
- St. Mary's MTS
- Tarentorus MTS
- Chapleau DS
- DA Watson TS

Peak contribution factors reflecting the portion of installed capacity available at the time of peak were calculated for the DERs in the region using historical hourly generation where available; these factors are shown in Table 5.1.2 below.

Table 5.1.2| Peak Contribution Factors (%)

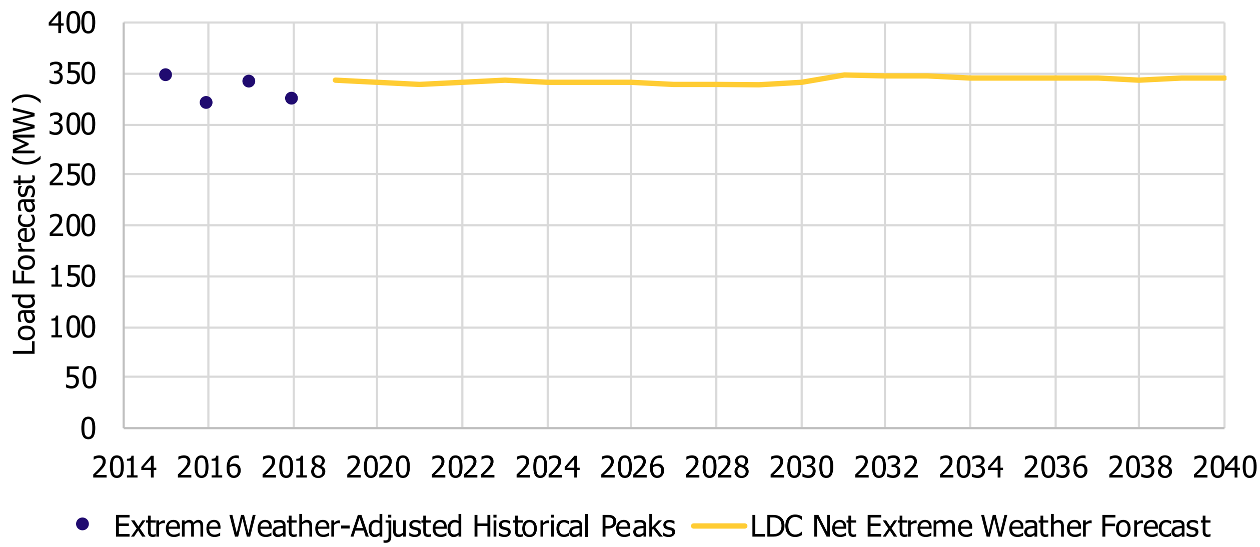
Fuel Type / Facility	Summer Contribution (%)	Winter Contribution (%)
Solar[3]	69	19
Algoma CHP	91	83
Chapleau Co-gen	72	53

5.1.3 Final Planning Forecast

The final net annual peak demand forecast developed for the IRRP is shown in Figure 5.1.3 and was used to carry out system studies that resulted in identifying the region's needs. As shown, the forecasted demand in the ELS Region is expected to remain relatively flat over the study period with a peak of 348 MW in 2031. This forecast includes distribution load plus existing industrial loads; it does not include a high industrial growth or expansion scenario, which will be considered as part of the IESO's bulk planning study in 2021 given the impact to the bulk transmission network in the broader region.

[3] The contribution factors for solar is based on actual summer and winter output from solar DG facilities connected to SSM PUC from 2016 to 2018. These represent the largest distribution connected solar facilities in the region.

Figure 5.1.3 | LDC Net Extreme Weather Forecast

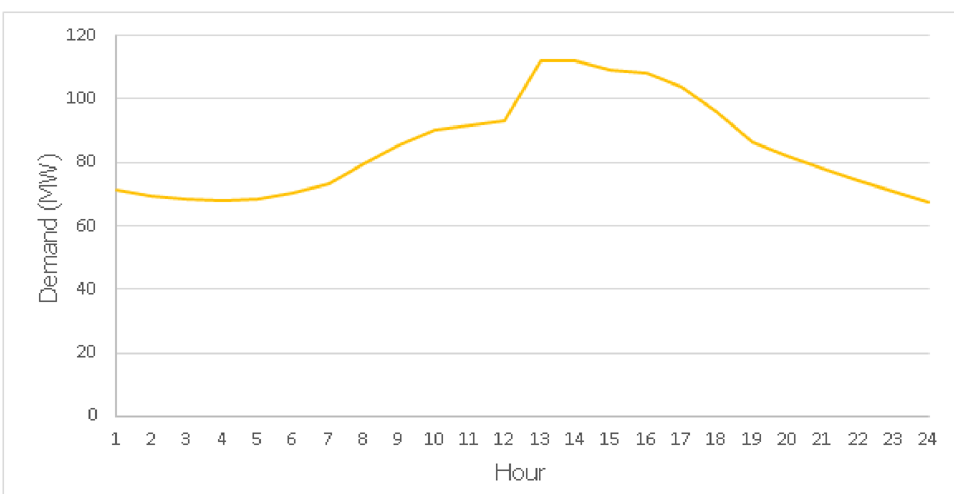


5.2 Load Duration Forecast (Load Profile)

In addition to the planning forecast developed for the purposes of identifying system needs, a load duration forecast was developed to further characterize the needs. Ultimately, the load duration forecast enables evaluation of the suitability of certain solution types to meet the area's magnitude, frequency and duration of needs. Using historical hourly duration information, a sample 8,760-hour profile was created and scaled such that the peak hour would align with the peak demand forecast in a given year of the planning horizon.

A sample of a typical peak-day profile for St. Mary's MTS and Tarentorus MTS is shown in Figure 5.2.

Figure 5.2 | St. Mary's MTS and Tarentorus MTS on January 19, 2040

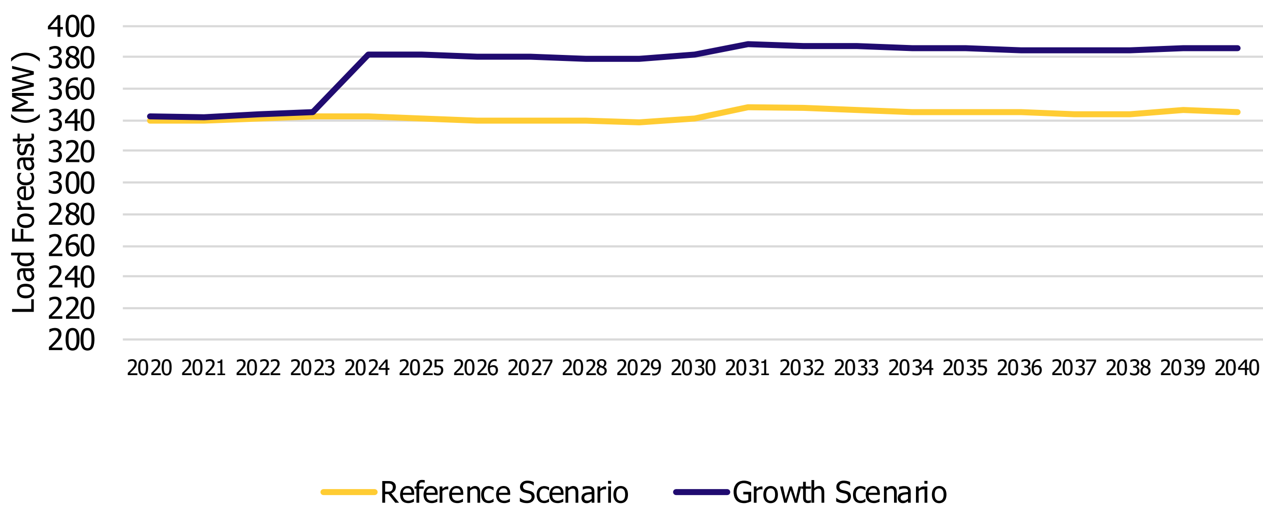


Additional details on the development of the load duration profiles are available in Appendix B.

5.3 Planning Forecast Sensitivity

In addition to the reference planning forecast, some of the LDCs also provided an incremental growth scenario. The reference forecast accounts for annual trend line growth which in the ELS region is fairly flat, when not considering high industrial growth, as seen in Figure 5.3. The incremental growth scenario takes into account large customer expansions and new potential customers that were uncertain at the time of forecast creation, 2% buffer for consideration of electric vehicles, customer expansions and new customers. These scenarios were taken into account in assessing the ELS region's needs and were studied as a sensitivity for the worst-case scenarios identified in the technical studies identified in Appendix D. The sensitivity results did not give rise to any new needs but did exacerbate existing needs in the area. Figure 5.3 shows the comparison between the reference planning demand forecast and the growth scenario. Note that this sensitivity does not capture the high industrial load growth that will be considered in the IESO's bulk planning study.

Figure 5.3 | Comparison Between Reference and Growth Scenario



6. Electricity System Needs

Based on the demand forecast, system assumptions and application of planning criteria, the Technical Working Group identified electricity needs for this region over the current planning period from 2020 to 2040. This section summarizes the needs identified for the ELS region. For practical purposes, not every forecast year is assessed. Year 1 (2020) is assessed to represent the present-day regional power system, Year 5 (2025) is assessed to represent the near-term planning horizon, Year 10 (2030) is assessed to represent the medium-term planning horizon, and Year 20 (2040) is assessed to represent the long-term planning horizon.

These needs are categorized in four groups in accordance with ORTAC and NERC criteria: step-down station capacity, system capacity and performance, load security and load restoration.

6.1 Step-Down Station Capacity Needs

Step-down transformer stations convert high-voltage electricity from the transmission system to lower-voltage electricity for delivery through the distribution system to end-use customers. Each station is capable of converting a certain amount of power on a continuous basis and a slightly higher amount of power for a short duration, typically 10 days, which is referred to as its Limited Time Rating (LTR). Loading a station beyond this amount is not permissible except in emergency conditions, as it lowers the life expectancy of facility equipment and can impact reliability for customers.

Step-down station capacity needs are determined by comparing the non-coincident station peak demand forecast to the facility's 10-day LTR. When a step-down station's capacity is reached, options for addressing the need include reducing peak demand in the supply area (e.g., through EE or DERs), or building new step-down transformer capacity to serve incremental growth.

Table 6.1 shows that there are no transformer capacity limitations for the ELS region in the planning forecast for planning years 2020, 2025, 2030 and 2040.

Table 6.1 | Step-down Station Capacity Needs

Station	Continuous Rating (MVA)	10-day LTR Rating (MVA)	2020 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Andrews TS	5.0	5.0	0.22	0.22	0.22	0.22
Batchawana TS	4.3	4.3	1.64	1.72	1.78	1.92
DA Watson TS	75.0	97.5	8.47	8.76	9.01	9.51
Echo River TS	25.0	25.0	14.05	14.46	14.79	15.61

Station	Continuous Rating (MVA)	10-day LTR Rating (MVA)	2020 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Goulais Bay TS	15.0	15.0	8.46	8.75	8.99	9.47
Limer TS (proposed TS)	TBD	TBD	37.0	54.0	56.0	56.0
MacKay TS	0.5	0.5	0.04	0.04	0.04	0.04
Northern Avenue TS	5.0	5.0	2.48	2.56	2.64	2.78
Chapleau DS	17.05	17.05	6.37	9.62	10.07	11.32
Chapleau MTS	10	10	4.31	4.68	4.37	4.29
St. Mary's+ Tarentorus MTS	210	210	116.11	112.30	111.09	112.21

6.2 System Capacity and Performance Needs

System capacity refers to the amount of power that can be supplied by the regional transmission network, either by bringing power in from other parts of the province, or by generating it locally.

System capacity in the ELS region was assessed by modelling power flows throughout the local grid under anticipated non-coincident peak demand conditions, and applying a series of standard contingencies (outage events) as prescribed by ORTAC and NERC. Co-incident peak demand was assumed for St. Mary's and Tarentorus TS because PUC Distribution Inc. is able to transfer loads between the two stations during peak demands to avoid overloading any of the transformers. Performance standards and criteria dictate how well the system must be able to operate following these contingencies. Standards at risk of not being met are identified as a system need. System performance before or following a disturbance must meet criteria identified in ORTAC section 4 and NERC standard TPL-001.

As with station capacity needs, system capacity needs can be addressed by upgrading the system to increase LMC, or addressed/deferred by reducing peak demand. Details on identified system capacity needs are described in the following sections.

6.2.1 Third Line Autotransformer Approaching Capacity

Third Line TS is a key supply point in the ELS region and consists of two 230/115 kV, 150/200/250 MVA autotransformers. The Third Line TS 230 kV station yard is supplied by circuits K24G extending to Mackay TS and P21G/P22G extending east to Mississagi TS. The Third line TS 115 kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, Sault No.3 circuit and Northern Avenue Line circuit. It also supplies the loads at St. Mary's and Tarentorus stations via 115 kV circuits GL1SM GL2SM, GL1TA, and GL2TA.

When one of the Third Line autotransformers is lost, the loading of the companion autotransformer approaches its 10-day LTR today. This was also identified in the Needs Assessment and the Scoping

Assessment. The loading on the companion transformer would be reduced modestly beyond 2023 when the Sault No.3 circuit returns to a network (non-radial) configuration. Sault No.3 is a 115 kV transmission circuit that runs from MacKay TS 115 kV station yard to Third Line TS 115 kV station yard. This circuit is currently de-rated due to deteriorating condition of the overhead conductor and operated normally-open at the Mackay TS terminal. Hydro One is currently planning to refurbish the circuit like-for-like as part of its planned sustainment activities to restore it to non-radial operation. The refurbished circuit is expected to be in-service by 2023.

This is not a firm need as there is no existing violations but this is flagged because loading on Third Line autotransformers is close to its LTR rating and should continue to be monitored. As mentioned in the Need Assessment, one of the Third Line autotransformers is scheduled to be replaced by 2025. However, the replacement autotransformer would not add any significant supply capacity to this region due to the ratings of a standard 230/115 kV autotransformer.

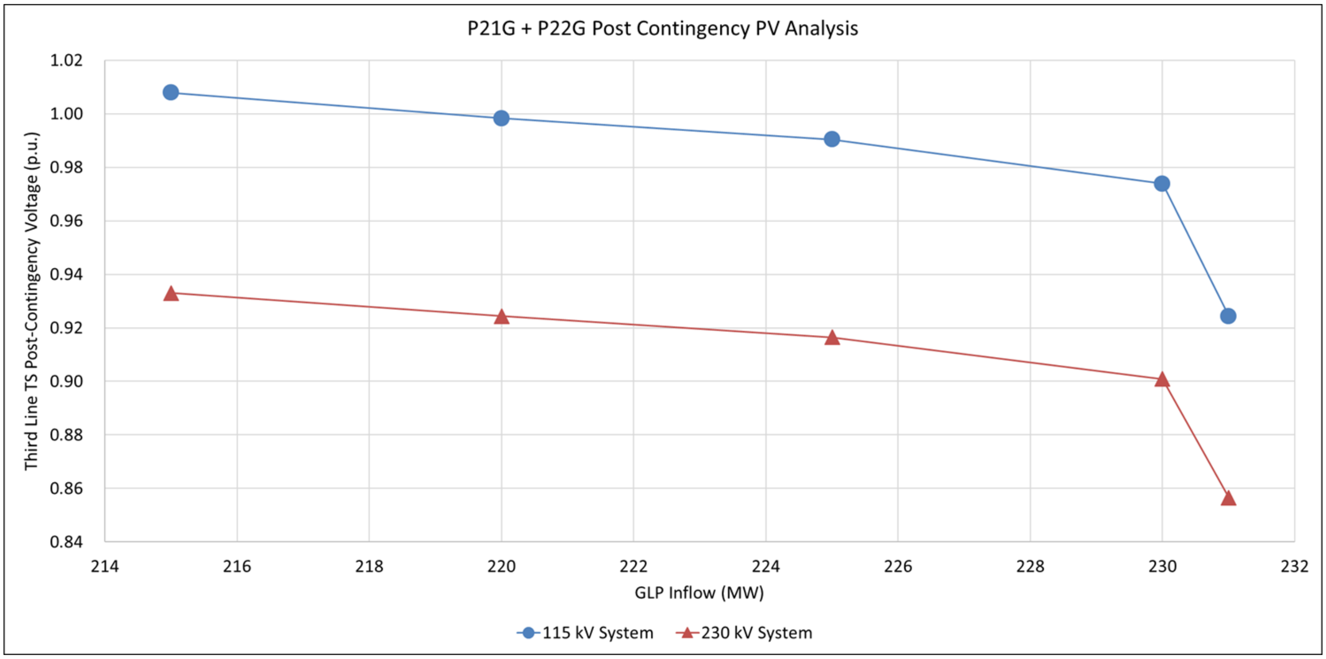
6.2.2 Voltage Concern Following the Loss of P21G/P22G

P21G and P22G are 230 kV circuits running from Third Line TS to Mississagi TS. These circuits form a critical supply path to the ELS region. A double circuit loss of P21G and P22G would cause voltage drop in excess of 10% (voltage collapse) at Third Line TS and other ELS stations throughout the planning period. This loss can be caused by an outage to the first circuit, followed by a contingency to the second or by a simultaneous loss of both circuits due to a contingency involving adjacent circuits on a common tower. Loss of P21G and P22G takes Third Line autotransformer T1 out of service by configuration. The voltage instability point is reached when GLP Inflow exceeds 230 MW and the circuits are out of service. [4] This is an existing issue today.

Third Line TS is equipped with Instantaneous Load Rejection Scheme with six load blocks to select for load shedding. Currently there is no provision in this scheme to allow remote arming of load rejection for the P21G+P22G double contingency. The IESO has to manually request Hydro One Sault Ste. Marie to arm certain amounts of load for rejection, and Hydro One Sault Ste. Marie prioritizes selection of the load blocks. The existing scheme has a provision to remotely arm load for this contingency, which would remove the need to initiate the manual procedure and hence, make the arming procedure more efficient.

[4] GLP Inflow is a system interface defined by the MW flow west at Mississagi TS on P21G and P22G circuits plus MW flow into Third Line TS on K24G circuit.

Figure 6.2.2| P21G + P22G Post Contingency PV Analysis



6.2.3 Capacity Overload of 115 kV Circuit No. 1 Algoma

A failure of breaker (BKF) 214 to operate at Patrick St TS will cause the loss of No. 2 Algoma and No. 3 Algoma circuits from Third Line TS to Patrick St TS. This results in thermal overload of the remaining No. 1 Algoma circuit beyond its short-term emergency (STE) rating during peak loads at Patrick St TS; note that No. 1 Algoma is the lowest rated circuit out of the three. This thermal overload of No. 1 Algoma can also occur with one of the Algoma circuits initially out of service, followed by the loss of another Algoma circuit.

This is an existing issue and thus an immediate need which was also identified in the Needs Assessment and Scoping Assessment. This is currently mitigated by the Patrick St TS manual load shedding scheme under which load is curtailed manually at Patrick St TS following the loss of one of the Algoma line circuits. This is done to prevent overloading of the No. 1 Algoma circuit in case the second circuit is also lost. Since this scheme is manual, load has to be shed before the actual contingency of the second circuit has taken place which is an event that may not occur. This scheme was designed as an interim solution until a more permanent solution was implemented.

6.2.4 Capacity Overload of 115 kV Circuit Sault No.3

During an outage to either the P25W or P26W circuit between Wawa TS to Mississagi TS, a contingency on the K24G circuit between Third Line TS and Mackay TS results in the thermal overload of the Sault No.3 circuit beyond its STE ratings starting in 2023 when Sault No.3 circuit is connected in a network configuration.[5] This phenomenon is a result of high East West Transfer (EWT) flows and losing two circuits that carry that flow.[6]

In addition, when one of the Third Line TS autotransformers is out of service, a normally operated Sault No.3 circuit (after its proposed upgrades) helps to alleviate overloading of the companion Third

[5] Sault No.3 circuit is being refurbished as part of a sustainment project

[6] EWT is defined as the MW flow at Wawa TS on circuits W21M and W22M.

Line TS autotransformer. However, if the second autotransformer is also lost, Sault No.3 circuit will be overloaded beyond its STE rating and causes a significant voltage decline in the 115kV area served by Third Line TS.

6.2.5 Anjigami T1/Hollingsworth T1 and T2 overload

Anjigami TS is connected to Wawa TS, Magpie TS, D. A. Watson and Hollingsworth TS. For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa based on the latest load forecast submitted by the LDC. This is consistent with 2014 Needs Assessment report finding that identified overloading on Hollingsworth TS – Transformer T2 / Anjigami TS – Transformer T1 due to load increases on the 44 kV system. HOSSM is working with the impacted LDC and proposed a solution of building a new 115/44 kV station, with a proposed named Limer TS (subject to change) that will tap off Hollingsworth 115 kV circuit to handle the load increase.

6.2.6 Bulk Area Needs

There is a potential for significant growth in industrial load in the ELS region over the planning period which would have a material impact on the bulk transmission system in the broader region. This growth will be considered as part of the IESO's bulk planning study which will commence in 2021.

Based on the reference load forecast included in this IRRP, the following bulk system need was identified and will be further considered as part of the bulk planning study described above. Following the loss of one of the 230 KV circuits, P25W or P26W circuits from Mississagi TS to Wawa TS, the companion circuit becomes loaded beyond its LTR rating under high westward power flow on the EWT.

6.3 Load Security Needs

The load security criteria in ORTAC Section 7.1 describes the maximum amount of load that can be interrupted following specified contingencies. A summary of the load security criteria can be found in Table 6.3. The load security criteria are met in the planning timeframe for the ELS region.

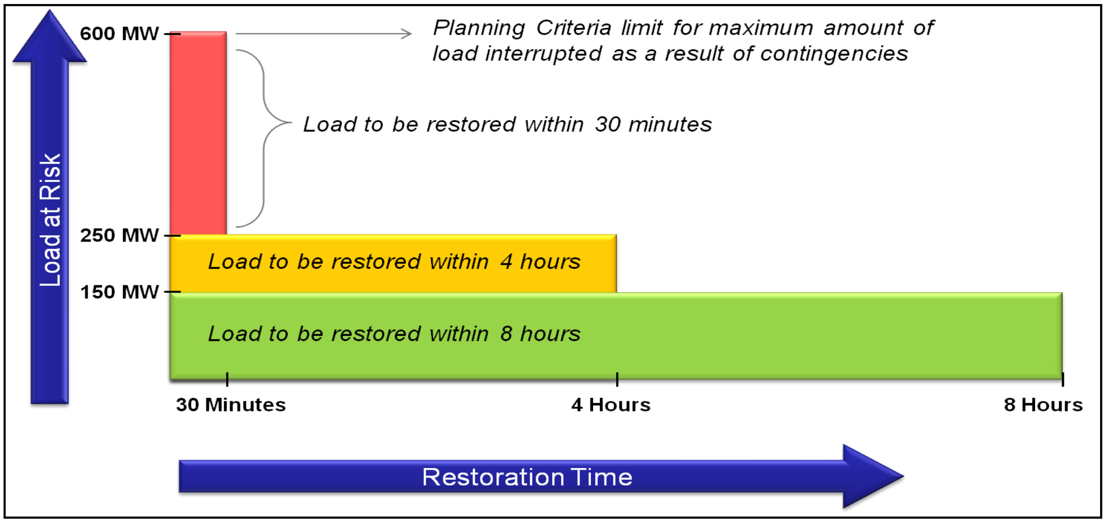
Table 6.3 | Load Security Criteria

Number of Transmission elements o/s	Local Generation Outage	Amount of load allowed to be interrupted by configuration	Amount of load allowed to be interrupted by load rejection or curtailment	Total amount of load allowed to be interrupted
One	No	≤ 150 MW	None	≤ 150 MW
One	Yes	≤ 150 MW	≤ 150 MW	≤ 150 MW
Two	No	≤ 600 MW	≤ 150 MW	≤ 600 MW
Two	Yes	≤ 600 MW	≤ 600 MW	≤ 600 MW

6.4 Load Restoration Needs

As described in Section 7.2 of ORTAC, load restoration criteria specify the maximum amount of time it can take to restore interrupted load. A visual representation of ORTAC's load restoration criteria is shown in Figure 6.4.

Figure 6.4 | Load Restoration Criteria



6.5 Summary of Identified Needs

Table 6.5 below summarizes the electric power system needs identified in the ELS region in this IRRP. All of the needs exist today or arise in the near term. Note that the Anjigami T1/Hollingsworth T1 and T2 overload is customer driven. Section 7 considers different options to meet these needs and ultimately makes recommendations on how to address them.

Table 6.5 | Summary of Needs in the ELS Region

Need	Need Date
Loss of one Third Line TS autotransformer causes the companion transformer to be loaded close to its capacity	This is not a need, but flagged for ongoing monitoring
Loss of P21G and P22G circuits causes voltage collapse at Third Line TS. Enabling remote arming of GLP Instantaneous Load Rejection Scheme will drive operational efficiencies	Immediate
Loss of two Algoma circuits or a Patrick St TS 214 BKF results in thermal overload of the remaining Algoma circuit	Immediate
During an outage of P25W or P26W circuits, a loss of the K24G circuit results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	2023

Need	Need Date
During an outage of one of the Third Line TS autotransformers, a loss of the companion autotransformer results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	2023
For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa	2024

7. Plan Options and Recommendations

This section describes and evaluates the options considered to address system needs in the ELS region. This includes an evaluation of each option and the recommendations for action.

7.1 Alternatives for Meeting Needs

This section outlines the options considered to address the needs identified in the ELS Region, including how these options were evaluated and the recommendations for action in the near term.

There are generally two types of approaches for addressing electricity needs in regional areas:

- Target measures to reduce peak demand to maintain loading within the system's existing limits largely through the use of EE, and other demand management strategies.
- Build new infrastructure to increase the LMC of the area.

DERs, including DR, EE measures, or energy storage are all well suited to the first approach.

Even if not being pursued to address specific system capacity needs, there are other potential benefits to non-wires investments, such as customer cost savings, and reducing GHG emissions. Some of these other objectives have been identified in the City of Sault Ste. Marie's Greenhouse Gas Emissions Reduction Plan.

Where reducing peak demand is not technically or economically feasible through the use of DERs, the other strategy is to upgrade the infrastructure to increase the LMC of the area. In cases where a step-down station exceeds its maximum capacity, the station can be expanded. If the transmission system is at its capacity, generally the options are to build new local generation (to reduce the amount of power that needs to be brought in from elsewhere), or build new or upgrade the existing transmission infrastructure to increase transfer capability. New remedial action schemes can also be introduced when transmission upgrades are not considered feasible at this time. These schemes can act to reduce load and/or generation to meet identified transmission system needs.

Each of these categories of options are further explored below as they relate to the needs in the ELS region.

7.1.1 Conservation

Conservation is important in managing demand in Ontario and plays a key role in maximizing the utilization of existing infrastructure and maintaining a reliable supply of electricity. Conservation is achieved through a mix of program-related activities including behavioural changes by customers and mandated efficiencies from building codes and equipment standards. These approaches complement each other to maximize conservation results.

On September 30, 2020 the IESO received a Ministerial directive to implement a new 2021-2024 CDM Framework. As discussed in Section 5.1.1., although the information about the new CDM Framework was not available when the forecast was being developed, continued program-driven CDM savings were included in the forecast consistent with the levels of the previous Interim Framework. The difference between these levels of expected savings is marginal. The new CDM Framework will contribute to lowering the net demand as seen on the transmission system; however, estimations of the savings in the area show that the identified needs still exist after these savings are accounted for.

Conservation expected to be achieved through time-of-use and codes and standards has already been included in the planning forecast scenarios.

While there is the potential for additional savings from CDM activities, beyond the levels assumed in the load forecast, these options were not investigated further at this time because the size of the need represents more than 66% of the winter peak demand of the ELS area. CDM programs tend to be more feasible and cost effective when the need represents much small percentage of the total system load (e.g., 2%).

For this reason, additional CDM activities were not considered further to address the immediate needs identified.

7.1.2 Local Generation

Local generation options were also considered to address the identified needs. A local generator, sited in the 115 kV system, could technically meet the reliability needs of the ELS region including the thermal overload of 115 kV circuit Sault No.3 and prevent arming of load for PxG contingency. The facility would need to be sized to deliver approximately 65 MW of winter peak capacity, when considering approximately 11 MW contribution from existing demand response in the region. In addition, the generation solution would have to address the annual energy requirements seen in Table 7.1.2 below. Based on these need characteristics, the NPV of a new combined cycle gas turbine (CCGT) generator was evaluated and estimated at $250 million, which includes capital costs, operating costs and credit for system capacity value to the broader system (as dictated by provincial needs and zonal capacity limitations). Based on economic analysis of available technology, the CCGT generator option is the cheapest utility scale non-transmission alternative. Given the cost of this option compared to those of the transmission options, this alternative was ruled out.

Table 7.1.2 | Energy Required to Address Reliability Needs at Third Line TS

	2020	2025	2030	2035	2040
Annual Energy Need (MWh)	224,000	196,000	168,000	153,000	122,000

7.1.3 Transmission

A number of transmission and distribution, or "wires," solutions were considered by the Technical Working Group to meet the near-term needs. "Wires" infrastructure solutions can refer to new or upgraded transmission or distribution system assets, including circuits, stations, or related equipment, and remedial action schemes.

The following remedial action schemes were considered by the Working Group to meet the system capacity and performance needs in the near term.

Enable Remote Arming for P21G+P22G in GLP Instantaneous Load Rejection Scheme

There is an existing RAS called the GLP Instantaneous Load Rejection Scheme that is initiated for the loss of both Third Line autotransformers or the loss of both P21G and P22G circuits. At present, a request has to be made to Hydro One Control Room to enable the scheme for the loss of P21G and P22G double contingency. It is a manual process where IESO Control Room has to call Hydro One Control Room and Hydro One arms the load. This scheme has a setting, which once enabled will allow IESO Control Room to arm load remotely, thus eliminating the need for the manual arming sequence and making the load rejection arming procedure more efficient. It would cost the transmitter approximately $50,000 to enable the remote arming setting in the RAS. Part of the change will require relevant Facility Description Document (FDD) and IESO System Control Order (SCO) documentation to be updated.

Automate Patrick St TS Manual Load Shedding Scheme

There is an existing Patrick St TS Manual load shedding scheme designed to manage the load at Patrick St TS. Loads at Patrick St TS are normally supplied by the three 115 kV Algoma circuits and from Clergue GS and load displacement generators at Algoma Steel Inc. Following contingencies that leave only one Algoma circuit in service, manual load shedding may be required. Since this process is not instantaneous, it also exposes the remaining Algoma circuit to an extremely high flow if the second circuit was to trip during the manual load shedding sequence. This scheme was originally designed as an interim solution until a more permanent solution was employed.

ORTAC provisions allow for planned load rejection up to 150 MW for any two elements out of service; however, a load shedding scheme would need to be automatic and allow load rejection of Patrick St TS load upon the loss of an Algoma circuit when another Algoma circuit is out of service. This solution would cost approximately $2 Million. This scheme can be expanded to arm load for the Patrick St TS 214 BKF.

Control Actions and System Reconfiguration for Overloading of Sault No.3

An operational control action such as opening Sault No.3 circuit between Sault Ste. Marie and the Mackay sub-system could be implemented when there is an outage to one of the 230 kV circuits P25W or P26W to avoid post-contingency overloading on the 115 kV Sault No.3 circuit. This would address the need on the Sault No.3 circuit but would also overload the companion 230 kV PxW circuit during high flows on the East West Tie.

During an outage to one of the Third Line TS autotransformers, Sault No.3 can become overloaded if the remaining autotransformer is also lost due to a contingency. The loads served by Third Line TS will also suffer a voltage decline beyond that permissible via ORTAC. To prevent these phenomena, one solution is to reject load; however, studies show that during peak demand conditions, more than 150 MW of load shedding may be required which violates ORTAC. Another potential solution is to reconfigure the system following the loss of the second transformer during peak conditions, however, this could similarly result in significant amounts of load lost by configuration.

Given that these needs involve facilities that will be considered in the IESO's 2021 bulk plan, they will be provided as input into the bulk planning study and the solutions to address them will be coordinated with the outcomes of the bulk planning study.

7.2 Recommended Plan to Address Local Needs

To meet identified electricity needs in the ELS region, the Technical Working Group recommends the implementation of the following actions:

Monitor Demand Growth and Supply in the Region

The Technical Working Group recommends closely monitoring demand growth and supply in the ELS region to determine if and when additional transformation capacity at Third Line TS is required. This includes monitoring the city of Sault Ste. Marie's climate plans, described further below, as they may have an effect on the demand.

The city of Sault Ste. Marie is planning on increasing community and corporate climate change initiatives through their community Green Gas Emissions Reduction Plan.[7] This plan sets out the actions required on a short, medium and long-term basis in order to reduce GHG emissions in the city of Sault Ste. Marie. The goal is for the city of Sault Ste. Marie to reduce their GHG emissions and be net zero by 2050. Actions have been broken down by sector which includes Buildings & Energy at a community level. The GHG reduction plan in the Buildings & Energy sector includes:

- Increase uptake in residential and commercial energy efficiency retrofits that reduce the use of fossil fuels;
- Increase the number of new homes and business builds to incorporate energy efficient equipment (e.g., new furnaces, weather stripping, efficient lighting, etc.);
- Research policies for efficient new builds that go above the Ontario Building Code;
- Develop a community energy efficiency retrofit program (either for energy efficiency retrofits or renewable energy); and
- Encourage the use of energy reduction devices such as thermal imaging heat devices.

These activities also have the potential to reduce electricity demand in the city of Sault Ste. Marie and are therefore important considerations as part of regional planning. The Working Group will continue to monitor implementation of these recommendations and their impact on the demand.

The Technical Working Group encourages potential new customers in the ELS Region to notify the IESO, HOSSM and their appropriate LDC of their growth or connection plans as soon as possible such that this growth can be reflected in ongoing planning in the region. If required, the next round of regional planning can be initiated early, i.e., before 5 years, should the demand follow the alternate growth scenario as described in section 5. The IESO will also continue to monitor potential non wires alternatives and implementation options.

[7] https://saultstemarie.ca/City-Services/City-Departments/Community-Development-and-Enterprise-Services/FutureSSM/Greenhouse-Gas-Emissions-Reduction-Plan.aspx?fbclid=IwAR1JDdn5-ZwoXP4uIZnu3C9Y-lOS3IFJnBmXqlY1DWdyQiAVQHj4bgF3R6c

The overall demand forecast for the ELS region is relatively flat over the planning period but has potential for significant growth resulting from large industrial load projects and expansions. This will be studied as part of an IESO bulk planning study.

Enable Remote Arming for P21G+P22G in GLP Instantaneous Load Rejection Scheme

The Technical Working Group recommends that HOSSM modify the existing GLP Instantaneous Load Rejection Scheme as soon as practical. This scheme would allow remote arming of load rejection, within amounts permissible via ORTAC, during periods of high demand in case the transmission circuits supplying Sault Ste. Marie (P21G and P22G) are both out of service, and would result in operational efficiencies over manual arming. The likelihood of rejecting the load as a result of both transmission circuits being out of service is low but must be planned for as per planning standards. The approximate cost of expanding this scheme is $50K.

Implement Automatic Load Rejection Scheme at Patrick St TS

The Working Group recommends HOSSM to implement a new automatic load rejection scheme to arm up to 75 MW of load rejection automatically during periods of high demand in case the companion circuits to No. 1 Algoma circuit are both out of service. This would solve the thermal issues to the electricity supply within Sault Ste. Marie at an approximate cost of $2 Million.

Coordinate with IESO's Bulk Planning Study Regarding Sault No.3 Circuit Overloading

Given that the facilities driving the needs related to the overloading of the Sault No.3 circuit will be considered in the IESO's 2021 bulk plan, it is recommended that these needs be carried forward as an input to the bulk plan so as to ensure a coordinated approach with respect to the outcomes and solutions developed as part of the bulk plan.

New 115/44 kV Station

The Technical Working Group has been informed that HOSSM plans on building a new 115/44 kV station that will tap off the Hollingsworth 115 kV circuit and will serve the incremental customer driven load. This is in line with the recommendation made in the Needs Assessment; HOSSM will work with the local LDC and customers when sizing and designing the new station.

7.3 Implementation of Recommended Plan

To ensure the electricity needs of the ELS area are addressed, it is important that the recommendations are implemented in a timely manner. The specific actions and deliverables associated with the plan are outlined in Table 7.3 below, along with their recommended timing and the parties with lead responsibility for implementation. The ELS Working Group will continue to meet regularly during the implementation phase of this IRRP to monitor developments in the ELS region and to track progress of these deliverables.

Table 7.3 | Implementation of Recommended Plan for ELS Region

Need	Recommendation	Lead Responsibility	Required By
Loss of one Third Line TS autotransformer causes the companion autotransformer to be loaded close to its capacity	Monitor load and supply in the ELS region	IESO/HOSSM	Immediately and Ongoing
Loss of P21G and P22G circuits causes voltage collapse at Third Line TS and other ELS stations	Enable remote arming of GLP Instantaneous Load Rejection Scheme for P21G and P22G double contingency for operational efficiency over manual arming	Hydro One	Immediately
Loss of two Algoma circuits or a Patrick St TS 214 BKF results in thermal overload of the remaining Algoma circuit	Implement automatic load rejection scheme at Patrick St TS	HOSSM	Immediately
During an outage of P25W or P26W circuits, a loss of the K24G circuit results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023
During an outage of one of the Third Line TS autotransformers, a loss of the companion autotransformer results in thermal overload of the Sault No.3 circuit (assuming this circuit is replaced like-for-like at end-of-life and operated in a network configuration)	Consider as part of the IESO's Bulk Planning Study for the broader region commencing in 2021	IESO/HOSSM	2023

For loss of Anjigami TS, there is an overload on Hollingsworth T1 and T2, and vice versa	Hydro One to work with the LDC to build a new 115/44 kV station that will tap off Hollingsworth 115 kV circuit to accommodate the load increase	HOSSM	2024

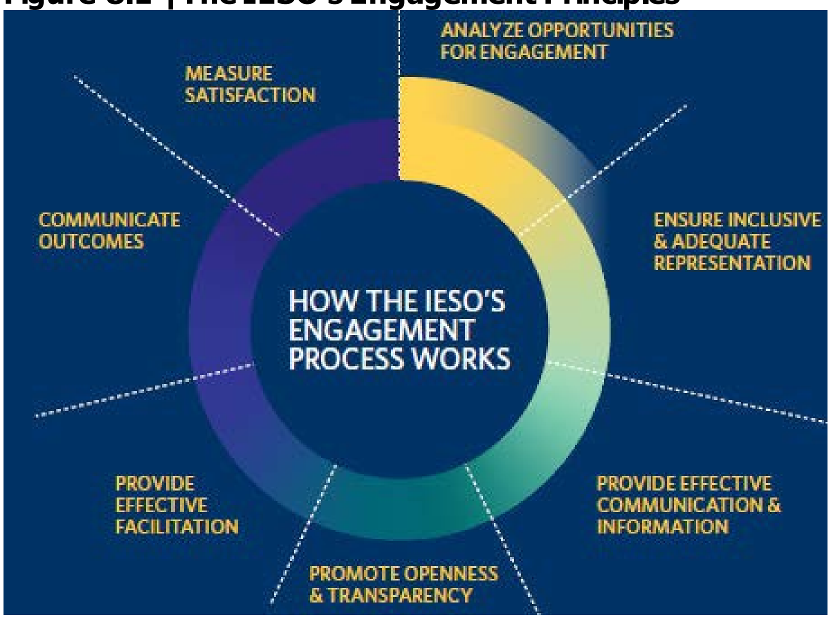
8. Engagement

Engagement is critical in the development of an IRRP. Providing opportunities for input in the regional planning process enables the views and preferences of communities to be considered in the development of the plan, and helps lay the foundation for successful implementation. This section outlines the engagement principles as well as the activities undertaken to date for the East Lake Superior IRRP.

8.1 Engagement Principles

The IESO's engagement principles help ensure that all interested parties are aware of and can contribute to the development of this IRRP.[8] The IESO uses these principles to ensure inclusiveness, sincerity, respect and fairness in its engagements, striving to build trusting relationships as a result.

Figure 8.1 | The IESO's Engagement Principles



8.2 Creating an Engagement Approach for ELS

The first step in ensuring that any IRRP reflects the needs of community members and interested stakeholders is to create an engagement plan to ensure that all interested parties understand the scope and are adequately informed about the background and issues in order to provide meaningful input on the development of the long-term electricity plan for the region.

[8] https://www.ieso.ca/en/sector-participants/engagement-initiatives/overview/engagement-principles

Creating the engagement plan for this IRRP involved: [9]

- Discussions to help inform the engagement approach for the planning cycle
- Developing and implementing engagement tactics to allow for the widest communication of the IESO's planning messages, using multiple channels to reach audiences
- Identifying specific stakeholders and communities that should be targeted for one-on-one consultation, based on identified and specific needs

As a result, the engagement plan for this IRRP included:

- A dedicated webpage on the IESO website to post all meeting materials, feedback received and IESO responses to the feedback throughout the engagement process[10]
- A dedicated section on the IESO's online engagement platform, IESO Connects, to provide an alternative mechanism for communities and interested parties to learn about the IRRP and offer any input[11]
- Regular communication with interested communities and stakeholders by email or through the IESO weekly Bulletin
- Public webinars
- Face-to-face meetings
- One-on-one outreach with specific stakeholders to ensure that their identified needs are addressed (See section 1.4 Outreach with Municipalities)

8.3 Engage Early and Often

Preliminary discussions were held early in the planning process to gain an understanding of key local energy priorities and help inform the engagement approach for this planning cycle. These discussions were important to establish and build new relationships as this round of planning marked the first cycle requiring regional coordination and community engagement.

Formal engagement began with an invitation to targeted communities and those with an identified interest in regional issues to learn about and provide comments on the ELS Scoping Assessment Report before it was finalized. Following a public webinar and written comment period, the final Scoping Assessment was published in October 2019 with responses to feedback received, which identified the need for an IRRP for the ELS region.

Outreach then began with targeted communities to inform early discussions for the development of the IRRP including the IESO's approach to engagement. The launch of a broader engagement initiative followed with an invitation to subscribers of the ELS region to ensure that all interested parties were made aware of this opportunity for input.

---

[9] https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/els/East-Lake-Superior-IRRP-Engagement-Plan-20200514.ashx

[10] https://www.ieso.ca/en/Sector-Participants/Engagement-Initiatives/Engagements/Regional-Electricity-Planning-East-Lake-Superior

[11] https://iesoconnects.ca/content/electricity-planning-east-lake-superior

Three public webinars were held at major junctures during IRRP development to give interested parties an opportunity to hear about its progress and provide comments on key components. Both webinars received cross-representation of stakeholders and community representatives attending the webinar and submitting written feedback during a 15-day comment period.

The first webinar sought input on the draft engagement plan, the electricity demand forecast and needs. Comments received during the webinar were related to the underlying numbers, factors and assumptions in the demand forecast. As a result of this feedback, further clarification was provided in subsequent engagement events and materials.

The second webinar sought feedback on the defined electricity needs for the region and potential options. Comments received during the written feedback window touched on the following major themes that has been considered in the development of this IRRP:

- Options development, specifically the consideration on non-wires alternatives (NWAs)
- Consideration of high industrial growth potential
- Access to data and information to enable the market to respond to regional electricity needs

As a final step in the engagement initiative, the third public webinar was held to seek input on the analysis of options and draft IRRP recommendations. Comments were received around the potential for non-wires options, particularly energy storage, to meet regional electricity needs and clarification on the economic assessment of options. Non-wires options including generation and CDM were considered in the analysis of potential solutions, and as discussed during the third webinar, no specific actions are required at this time. The uptake of non-wires resources will be monitored as part of ongoing monitoring and planning for the ELS region.

Based on the discussions both through the ELS IRRP engagement initiative and the IESO's Regional Electricity Networks, it is clear that there is broad interest to further discuss the potential for alternative energy solutions in supporting future growth. [12] Ongoing discussions will continue through the IESO's Northeast Regional Electricity Network to keep communities and interested parties engaged on local developments, priorities and planning initiatives in preparation for the next planning cycle. [13]

All background information, including engagement presentations, recorded webinars, detailed feedback submissions, and responses to comments received, are available on the IESO's ELS IRRP engagement web page.

8.4 Bringing Communities to the Table

The IESO held meetings with the City of Sault Ste. Marie, large industrial customers and energy service providers in the region to seek input on major planning and development projects and to ensure that local initiatives were taken into consideration in the development of this IRRP. These meetings helped to inform the region's electricity needs and provided opportunities to strengthen these relationships for ongoing dialogue beyond this IRRP process.

[12] https://ieso.ca/en/Get-Involved/Regional-Planning/Electricity-Networks/Overview

[13] https://iesoconnects.ca/collections/northeast-regional-electricity-network

9. Conclusion

The ELS IRRP identifies electricity needs in the region over the 20-year period from 2020 to 2040, recommends a plan to address immediate and near-term needs, and identifies needs that are related to the bulk transmission system in the broader region that should be further considered as part of the IESO's bulk planning study for the region, commencing in 2021, to ensure a coordinated approach with respect to outcomes.

Specifically, the IRRP includes recommendations to monitor load growth and supply in the region, and implement remedial action schemes to ensure the reliability of the system supply within the region. The IRRP also recommends that the needs identified with respect to the overloading of the Sault No.3 circuit be considered as part of the IESO's bulk planning studies for the area in 2021 given that these facilities will also be considered in the bulk study.

Responsibility for these actions has been assigned to the appropriate members of the Technical Working Group. Information gathered and lessons learned as a result of these activities will inform development of the next iteration of the regional planning for the ELS region.

The Technical Working Group will continue to meet at regular intervals to monitor developments and track progress toward plan deliverables. In the event that underlying assumptions change significantly, local plans may be revisited through an amendment, or by initiating a new regional planning cycle sooner than the five-year schedule mandated by the OEB.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.

East Lake Superior Region Integrated Regional Resource Plan

Appendices

MAY, 2021

Document ID Number
Issue Number
IESO Confidential

Connecting Today.
Powering Tomorrow.

Table of Contents

Appendix A. Overview of the Regional Planning Process

A.1 The Regional Planning Process

In Ontario, meeting the electricity needs of customers at a regional level is achieved through regional planning. This comprehensive process starts with an assessment of the interrelated needs of a region—defined by common electricity supply infrastructure—over the near, medium, and long term and results in the development of a plan to ensure cost-effective, reliable electricity supply. Regional plans consider the existing electricity infrastructure in an area, forecast growth and customer reliability, evaluate options for addressing needs, and recommend actions.

Regional planning has been conducted on an as-needed basis in Ontario for many years. Most recently, planning activities to address regional electricity needs were the responsibility of the former Ontario Power Authority (OPA), now the Independent Electricity System Operator (IESO), which conducted joint regional planning studies with distributors, transmitters, the IESO and other stakeholders in regions where a need for coordinated regional planning had been identified.

In the fall of 2012, the Ontario Energy Board (OEB) convened a Planning Process Working Group (PPWG) to develop a more structured, transparent, and systematic regional planning process. This group was composed of electricity agencies, utilities, and other stakeholders. In May 2013, the PPWG released its report to the OEB (PPWG Report), setting out the new regional planning process. Twenty one electricity planning regions were identified in the PPWG Report, and a phased schedule for completion of regional plans was outlined. [1] The OEB endorsed the PPWG Report and formalized the process timelines through changes to the Transmission System Code and Distribution System Code in August 2013, and to the former OPA's licence in October 2013. The licence changes required it to lead two out of four phases of regional planning. After the merger of the IESO and the OPA on January 1, 2015, the regional planning roles identified in the OPA's licence became the responsibility of the IESO.

[1] http://www.ontarioenergyboard.ca/OEB/_Documents/EB-2011-0043/PPWG_Regional_Planning_Report_to_the_Board_App.pdf

The regional planning process begins with a Needs Assessment process performed by the transmitter, which determines whether there are needs requiring regional coordination. If regional planning is required, the IESO conducts a Scoping Assessment to determine what type of planning is required for a region. A Scoping Assessment explores the need for a comprehensive IRRP, which considers conservation, generation, transmission, and distribution solutions, or whether a more limited "wires" solution is the preferable option, in which case a transmission- and distribution-focused Regional Infrastructure Plan ("RIP") can be undertaken instead. There may also be regions where infrastructure investments do not require regional coordination and can be planned directly by the distributor and transmitter outside of the regional planning process. At the conclusion of the Scoping Assessment, the IESO produces a report that includes the results of the needs assessment process and a preliminary terms of reference. If an IRRP is the identified outcome, the IESO is required to complete the IRRP within 18 months. If a RIP is the identified outcome, the transmitter takes the lead and has six months to complete it. Both RIPs and IRRPs are to be updated at least every five years. The draft Scoping Assessment Outcome Report is posted to the IESO's website for a two-week public comment period prior to finalization.

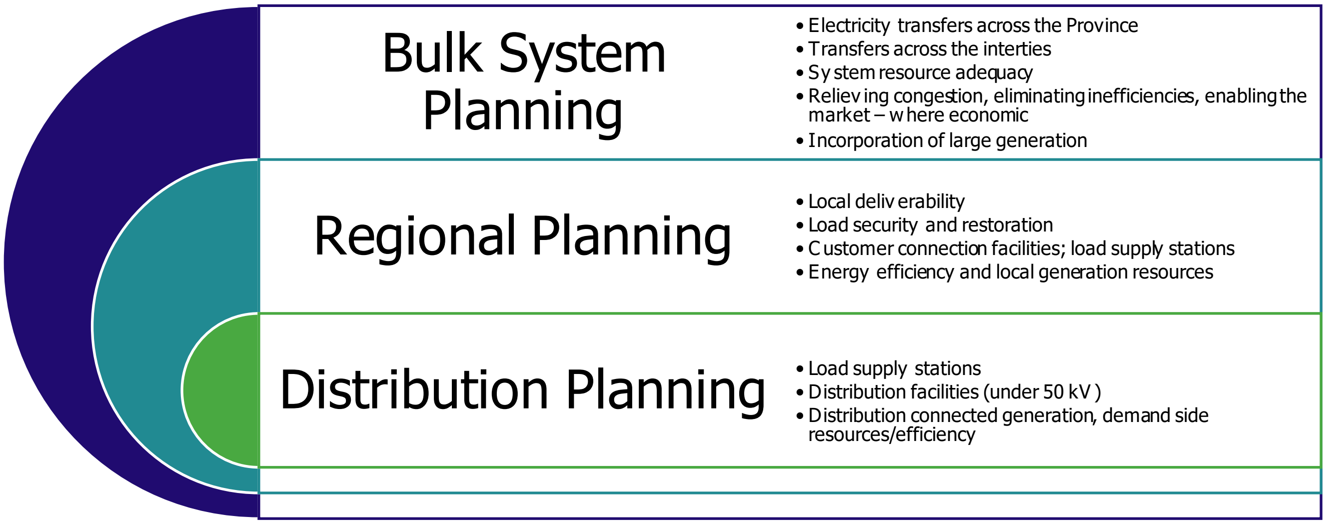
The final Needs Assessment Reports, Scoping Assessment Outcome Reports, IRRPs and RIPs are posted on the IESO's and the relevant transmitter's web sites, and may be referenced and submitted to the OEB as supporting evidence in rate or "Leave to Construct" applications for specific infrastructure investments. These documents are also useful for municipalities, First Nation communities and Métis community councils for planning, and for conservation and energy management purposes. They are also a useful source of information for individual large customers that may be involved in the region, and for other parties seeking an understanding of local electricity growth, CDM and infrastructure requirements. Regional planning is not the only type of electricity planning undertaken in Ontario. As shown in Figure A.1, three levels of electricity system planning are carried out in Ontario:

- Bulk system planning
- Regional system planning
- Distribution system planning

Planning at the bulk system level typically considers the 230 kV and 500 kV network and examines province-wide system issues. In addition to considering major transmission facilities or "wires", bulk system planning assesses the resources needed to adequately supply the province. Distribution planning, which is carried out by local distribution companies ("LDCs"), considers specific investments in an LDC's territory at distribution-level voltages.

Regional planning can overlap with bulk system planning and with the distribution planning of LDCs. For example, overlaps can occur at interface points where there may be regional resource options to address a bulk system issue or when a distribution solution addresses the needs of the broader local area or region. As a result, it is important for regional planning to be coordinated with both bulk and distribution system planning, as it is the link between all levels of planning.

Figure A.1 | Levels of Electricity System Planning



By recognizing the linkages with bulk and distribution system planning, and coordinating the multiple needs identified within a region over the long term, the regional planning process provides a comprehensive assessment of a region's electricity needs. Regional planning aligns near- and long-term solutions and puts specific investments and recommendations coming out of the plan into perspective. Furthermore, in avoiding piecemeal planning and asset duplication, regional planning optimizes ratepayer interests, allowing them to be represented along with the interests of LDC ratepayers, and individual large customers. IRRPs evaluate the multiple options that are available to meet the needs, including conservation, generation, and "wires" solutions. Regional plans also provide greater transparency through engagement in the planning process, and by making plans available to the public.

Appendix B. Demand Forecast

This Appendix describes the methodologies used to develop the demand forecast (peak and duration) for the East Lake Superior (ELS) Region IRRP studies. Forward-looking estimates of electricity demand were provided by each of the participanting LDCs and informed by the forecast base year and starting point provided by the IESO. The sections that follow describe the method used by the IESO to determine the forecast starting point, the approaches and methods used by each LDC to forecast demand in their respective service area, the conservation and DG assumptions and the duration forecast methodology.

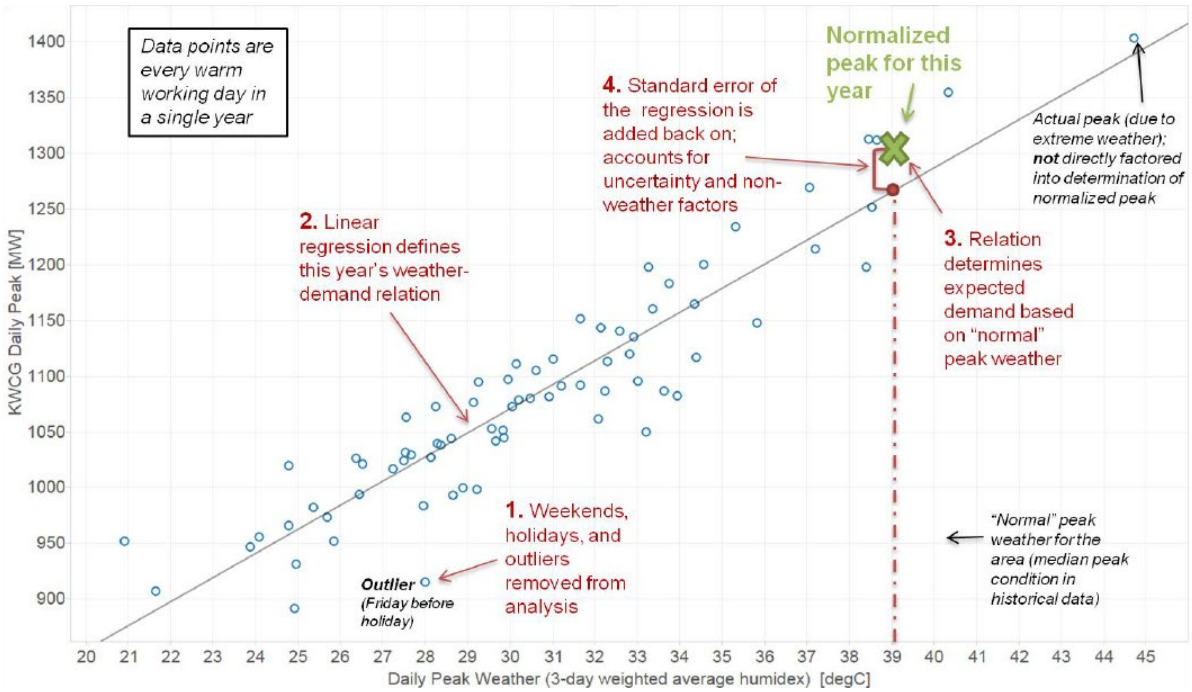
B.1 Method for Determining Forecast Starting Point

To develop a standardized starting point for the ELS region demand forecast, the following steps were performed:

- 5-year i.e., 2014-2018, historical non-coincident peak demand data was gathered for each station.
- Historical demand data was weather normalized to reflect median peak weather conditions at each station
- Historical output from Distributed Generation at the time of peak was added back to the historical demand for each year (because DG output is subtracted from the gross forecast).
- The starting point is typically selected using the most recent weather-corrected gross peak load; previous year's data points are used to observe trends and outliers.

In order to weather-normalize the data, historical demand was adjusted to reflect the median peak weather conditions for each transformer station in the area for all historical years. Median peak refers to the expected peak demand under the most likely, or 50th percentile, weather conditions. This means that in any given year there is an estimated 50% chance that the actual peak demand will exceed this peak, and a 50% chance that the actual peak demand will be lower than this peak. The methodological steps are described in Figure B-1; note that this is an illustrative example that was developed for a different region.

Figure B.1 | Method for Determining The Weather-Normalized Peak



The impact of Distributed Generation was then added to the median weather peak for all historical years and the most recent year (2018) was used as a starting point, for each LDC station. This data was provided to the LDCs to inform the starting point of their 20-year demand forecasts, which were developed using the their preferred methodology (described in Appendix B.2, below).

Once the LDC 20-year, median peak demand forecasts were provided to the IESO, the forecast was adjusted to reflect the impact of extreme weather conditions on electricity demand. The studies used to assess the reliability of the electric power system generally require the use of extreme weather demand forecasts, or, expected demand under the coldest weather conditions (in the case of ELS, which is a winter peaking region) that can be reasonably expected to occur. Peaks that occur during extreme weather (e.g., winter polar vortexes) are generally when the electricity system infrastructure is most stressed. The extreme weather adjustment factors used in the ELS IRRP were calculated as per IESO's methodology for modelling extreme weather conditions, which determines the relationship between weather and demand for a given region in a given timeframe.

B.2 LDC Forecast Methodologies

This section describes the methodologies used by the participating LDCs to develop their planning forecasts. These include:

- PUC Distribution Inc.
- Algoma Power Inc.
- Hydro One Networks Distribution

B.2.1 PUC Distribution Inc.

For its load forecast, PUC Distribution Inc. utilizes a regression analysis methodology that was approved by the OEB in its 2013 Cost of Service application and is used by multiple LDCs across the Province. PUC Distribution's weather normalized load forecast is developed in a three-step process. First, a total system weather normalized forecast is developed based on a regression analysis that incorporates variables that impact PUC Distribution usage. Second, the weather normalized forecast is adjusted by a historical loss factor to produce a weather normalized billed forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast. The forecast of customers by rate class is determined using a geometric mean analysis and judgment of PUC Distribution. For those rate classes that use kW for the distribution volumetric billing determinant an adjustment factor is applied to the class energy forecast based on the historical relationship between kW and kWh. For further details, please refer to PUC Distribution's OEB IRM application EB-2017-0071 Exhibit 3.

Furthermore, PUC Distribution Inc. considers other supplemental factors derived through its routine planning processes as described in its Distribution System Plan, also filed with the OEB as part of its Cost of Service application. These include potential impacts to the load forecast determined through stakeholder consultations:

- Customer Engagement (residential surveys, large C&I plans, developers, DG and REG customers)
- Municipal Government Consultations (City budgets, official plans, economic development plans, population projections)

For the load forecast period considered in this regional planning report, these additional supplemental factors did not contribute materially to the forecast determined through the regression methodology.

B.2.2 Algoma Power Inc.

Algoma Power Inc. ("API") provides electricity distribution services in the remote areas of Northern Ontario located north and east of the City of Sault Ste. Marie. API serves approximately 12,000 customers on a distribution system consisting of 1,861 kilometers of distribution line. The distribution system extends 93 Km east and approximately 255 Km north of the City of Sault Ste. Marie.

API distributes electricity to widely dispersed residential, seasonal, commercial and industrial customers as well as remote First Nations communities. Organized townships are governed by 14 separate municipal governments and the seven First Nation reserve locations are governed by four First Nations. Apart from property owned by businesses or individuals, API's territory also consists of significant parcels owned by large resource-based companies or provincial parks.

API experiences its peak demand mostly within the winter months due to lack of natural gas heating, a high penetration of electric heating, and a relatively low penetration of central air conditioning in much of its service area. Variances in seasonal peaks are attributable to the varying weather conditions experienced in Northern Ontario.

API follows a trend load forecasting methodology, where future loads are extrapolated based on recent and past peak loads for each connected supply point. A baseline forecast is developed with consideration to normal operating conditions, coincident peak loading and extreme weather conditions. From the established baseline year, a predefined growth rate is applied, which typically accounts for average annual load growth increase, but also factors in known future municipal and industrial developments. Consideration is also given to market trends in potential electricity needs, such as the anticipated deployment of electric vehicles.

B.2.3 Hydro One Networks Distribution

Hydro One Distribution services the areas in East Lake Superior region that are not served by other LDCs through Chapleau DS. Hydro One Distribution used both the econometric and end-use forecasting to develop the 20-year forecast provided to IESO.

A baseline forecast (MW station peak in the the base year) was developed, taking into account such factors as normal operating conditions, coincident peak loading, and extreme weather conditions.

For the ELS IRRP Forecast, Hydro One Distribution used the weather corrected peak demand levels for Chapleau DS.

From the established baseline year, a growth rate (%) was applied to station demand level to provide forecast values for Chapleau DS within the study timeframe.

Assumptions included in the growth rate can be related to such factors as: Ontario GDP growth rate, housing statistics, the intensification of urban developments (i.e., MW/sq.ft); and the need for large scale electrification projects.

Detailed information about load growth, based on local knowledge and relation between local and provincial load was used to augment the forecast values within the study period.

B.3 Conservation Assumptions in ELS Forecast

Conservation measures can reduce the electricity demand and their impact can be separated into the two main categories: Building Codes & Equipment Standards, and CDM Programs. The assumptions used for the ELS IRRP forecast take into account the conservation programs from the provincial Interim Framework. The savings for each category were estimated according to the forecast residential, commercial, and industrial gross demand. A top down approach was used to estimate peak demand savings from the provincial level, to the Northeast transmission zone and then allocated to ELS region. This section describes the process and methodology used to estimate conservation savings for the ELS Region and provides more detail on how the savings for the two categories were developed.

B.3.1 Estimate Savings from Building Codes and Equipment Standards

Ontario building codes and equipment standards set minimum efficiency levels through regulations and are projected to improve and further contribute to demand reduction in the future. To estimate the impact on the region, the associated peak demand savings for codes and standards were estimated for the Northeast zone and compared with the gross peak demand forecast in the zone.

From this comparison, annual peak reduction percentages were developed for the purpose of allocating the associated savings to each TS in the region.

Consistent with the gross demand forecast, 2018 is determined as the base year. New peak demand savings from codes and standards were estimated. The residential annual peak reduction percentages of each year were applied to the forecast residential demand at each TS to develop an estimate of peak demand impacts from codes and standards. By 2038, the residential sector in the region is expected to see about 4.0% peak demand savings through standards. The same is done for the commercial sector, which will see about 0.3% peak-demand savings through codes and standards by 2038. The sum of the savings associated with the two sectors are the total peak demand impact from codes and standards. There are no savings from codes and standards considered to be associated with the industrial sector.

B.3.2 Estimate Savings from Conservation Programs

In addition to codes and standards, the delivery of CDM programs reduces electricity demand. The impact of existing and committed CDM programs were analyzed, which take into account both policy-driven and funded CDM. These include the Conservation First Framework wind-down and the Interim Framework. While the new 2021-2024 Conservation and Demand Management (CDM) framework was not taken into account (as it was not in place at the time of forecast development), sensitivities were conducted to assess its impact as described in Section 5.1.1 of the IRRP. A top down approach was used to estimate the peak demand reduction due to the delivery of 2019 and 2020 programs, from provincial to Northeast to the TSs in the region. Persistence of the peak demand savings from energy efficiency programs were considered over the forecast period.

Similar to the estimation of peak demand savings from building codes and equipment standards, annual peak demand reduction percentages of program savings were developed by sector. The sectoral percentages were derived by comparing the forecasted peak demand savings with the corresponding gross forecasts in Northeast transmission zone. They were then applied to sectoral gross peak forecast of each TS in the region. By 2020, the residential sector in the region is expected to see about 0.2% peak demand savings through programs, while commercial sector and industrial sector will see about 2.2% and 1.0% peak reduction respectively. Those savings will decay over time as the energy efficiency measures come to the end of their effective useful lives.

B.3.3 Total Conservation Savings and Impact on the Planning Forecast

As described in the above sections, peak demand savings were estimated by sector. Winter peak demand savings by TS were summarized in Table B.3.3. The analyses were conducted under normal weather conditions and can be adjusted to reflect extreme weather conditions. The resulting forecast savings, along with the impact of distributed generation resources, were applied to gross demand to determine net peak demand for further planning analyses.

Table B.3.3 | Forecast of Expected Winter Peak Demand Savings (MW) Due to Codes and Standards and Funded CDM Programs - by Station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
DA Watson TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Echo River TS	0.11	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.24	0.27	0.30	0.32	0.33	0.34	0.34	0.34
Goulais Bay TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Limer TS	0.11	0.19	0.19	0.19	0.15	0.15	0.15	0.15	0.15	0.15	0.17	0.19	0.23	0.25	0.28	0.30	0.32	0.32	0.32	0.32
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.02	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.06	0.06	0.06	0.06
Chapleau DS	0.07	0.12	0.12	0.12	0.10	0.10	0.10	0.10	0.10	0.10	0.12	0.13	0.16	0.18	0.20	0.22	0.23	0.23	0.23	0.23
Chapleau MTS	0.03	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.06	0.07	0.07	0.08	0.09	0.09	0.09	0.09	0.09
St. Mary's TS	0.91	1.58	1.54	1.54	1.16	1.16	1.13	1.12	1.12	1.08	1.17	1.29	1.46	1.60	1.76	1.87	1.93	1.91	1.88	1.86
Tarentorus TS	1.16	2.02	1.97	1.98	1.49	1.48	1.45	1.43	1.43	1.39	1.50	1.66	1.88	2.05	2.25	2.40	2.47	2.44	2.41	2.38
Total	**2.56**	**4.45**	**4.36**	**4.39**	**3.33**	**3.32**	**3.27**	**3.23**	**3.23**	**3.15**	**3.45**	**3.84**	**4.39**	**4.82**	**5.32**	**5.69**	**5.87**	**5.84**	**5.79**	**5.74**

B.4 Distributed Energy Resources Assumptions in ELS Forecast

Besides conservation savings, the expected peak contribution of existing and contracted DERs in the area were also taken into account.

Table B.4 | DER Forecast by Station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DA Watson TS	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Echo River TS	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.16	0.12	0.08	0.02	0.01	0.00	0.00	0.00
Goulais Bay TS	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Limer TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau DS	2.65	2.65	2.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau MTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
St. Mary's TS	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	0.23	0.18	0.16	0.16	0.16	0.14	0.00	0.00
Tarentorus TS	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	0.14	0.10	0.06	0.03	0.03	0.02	0.00	0.00	0.00

B.5 Final Peak Forecast by Station

After taking the median weather forecast provided by LDCs and applying the CDM assumptions above, forecasts were adjusted to extreme weather. The final peak demand forecasts, by station, are provided below:

Table B.5 | Winter Peak Demand Forecast (MW) by Station

Transformer Station	2019	2020	2021	2022	2023	2024	2025 2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	1.65	1.66	1.66	1.67	1.67	1.68	1.69	1.69	1.71	1.72	1.73	1.74	1.76	1.78	1.79	1.81	1.83	1.85	1.86	1.88
DA Watson TS	8.53	8.57	8.55	8.56	8.57	8.58	8.60	8.63	8.67	8.71	8.75	8.80	8.87	8.93	8.99	9.06	9.13	9.20	9.26	9.32
Echo River TS	14.18	14.23	14.19	14.19	14.17	14.18	14.20	14.23	14.28	14.33	14.38	14.45	14.57	14.67	14.80	14.95	15.06	15.17	15.25	15.33
Goulais Bay TS	8.53	8.56	8.55	8.56	8.56	8.57	8.59	8.62	8.65	8.70	8.74	8.79	8.84	8.90	8.97	9.03	9.11	9.18	9.24	9.30
Limer TS (proposed TS)	13.18	13.74	13.81	13.88	13.99	54.00	54.00	54.00	54.00	54.00	54.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00
Andrews TS	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Mackay TS	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Northern Av TS	2.50	2.51	2.50	2.51	2.51	2.51	2.52	2.53	2.54	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.67	2.70	2.71	2.73
Chapleau DS	6.31	6.47	6.51	9.24	9.32	9.38	9.44	9.51	9.59	9.68	9.76	9.84	9.94	10.03	10.13	10.23	10.33	10.44	10.53	10.63
Chapleau MTS	4.47	4.36	4.44	4.19	4.69	4.58	4.59	3.89	4.21	4.15	4.14	4.27	4.27	4.27	4.27	4.28	4.29	4.29	4.29	4.30
PUC Distribution Inc.	120.7	119.5	117.5	115.9	114.2	112.7	111.4	110.0	108.9	107.9	106.8	109.7	116.5	115.7	114.9	114.2	113.6	112.9	112.3	111.5

B.6 Duration Forecast Methodology

B.6.1 General Methodology

A load duration forecast consists of a series of year long hourly profiles ("8760 profile", based on the number of hours in a year), which have been scaled to the appropriate annual peak demand. These profiles are studied to determine the feasibility of using non-wires alternatives to address needs in the region, and to determine which type of non-wires alternatives may be best suited to meet the needs.

Hourly load forecasting was conducted on a station-level, using a multiple linear regression with approximately five years' worth of historical hourly load data. Firstly, a density-based clustering algorithm was used for filtering the historical data for outliers (including fluctuations possibly caused by load transfers, outages, or infrastructure changes).

Subsequent to the removal of outliers, the historical hourly data was combined with select predictor variables to perform a multiple linear regression and model the station's hourly load profile. For the ELS region, the following predictor variables were used:

- Calendar factors (such as holidays and days of the week)
- Weather factors (including temperature, dew point, wind speed, cloud cover, and fraction of dark; both weekday and weekend heating, cooling, and dead band splines were modelled)
- Demographic factors (population data[2])
- Economic factors (employment data[3])

Model diagnostics (training mean absolute error, testing mean absolute error) were used to gauge the effectiveness of the selected predictor variables and to avoid an over-fitted model. While future values for calendar, demographic, and economic variables were incorporated in a relatively straightforward manner, the unreliability of long-term weather forecasts necessitated a different approach for predicting the impact of future weather.

Each future date was first modelled using historical weather data from the equivalent day of year throughout the past 10 years. Additionally, to fully assess the impact of different weather sequences against the other non-weather variables, the historical weather for each of the 10 previous years was shifted both ahead and behind up to seven days, resulting in 15 daily variations. This approach ultimately led to 150 possible hourly load forecasts for each future year being forecast. For example:

- 10 years of historical weather data ×15 weather sequence shifts =150 weather scenarios for each year being forecast
- E.g., June 2nd 2025 was forecasted assuming the historical weather from every May 26th to June 9th that occurred between 2011 and 2020.

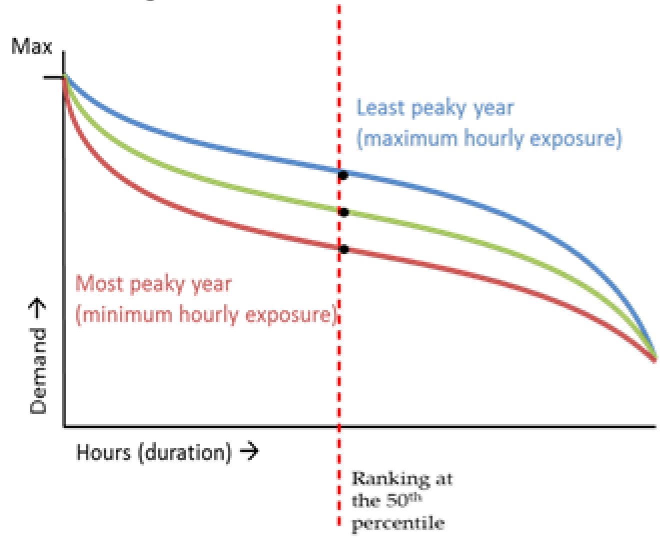
Subsequently, the list of 150 forecasts were ranked in ascending order based on their median values. Load duration curves which illustrate this ranking can be seen in Figure B-5.

---

[2] Sourced from the Ministry of Finance and Statistics Canada

[3] Sourced from the Centre for Spatial Economics, IHS Markit Ltd., and the Conference Board of Canada

Figure B.6 | Example of Ranking Load Duration Curves Created from Hourly Load Profiles



The forecast in the 3rd percentile was chosen as the "Extreme Peak" (extreme profile, red curve) and the forecast in the 50th percentile was chosen was the "Median Peak" (median profile, green curve).

The yearly forecasts were scaled to their respective maximums from the peak demand forecast, and added together to form a single multi-year forecast.

B.6.2 St. Mary's MTS and Tarentorus MTS

For the purpose of this IRRP, need characterization was done for St Mary's MTS and Tarentorus MTS. These stations are prioritized first in the existing GLP Instantaneous L/R scheme and are located in an area linked to the needs identified in the study (i.e., they are served by Third Line TS).

The historical hourly data for both stations was combined and one linear regression model was used. Once the 150 normalized forecasts were created, they were scaled to PUC Distribution's extreme weather peak demand forecast. The load duration forecast provided information regarding the amount by which the load is expected to exceed the limit of 42 MW (forecasted peak demand less load rejection required for the P21G + P22G double contingency) as well as the amount of time spent over the limit, or the total event hours. Table B.6.2 shows the annual energy requirements based on this information.

Table B.6.2 | Energy Required to Address Reliability Needs at Third Line TS

	2020	2025	2030	2035	2040
Annual Energy Need (MWh)	224,000	196,000	168,000	153,000	122,000

Figure B.6.2 is a visual representation of the percentage of the total event hours that are associated with each range of capacity need for the 2019 and 2040 load duration forecasts. For example, in 2019 approximately 4% of the total time spent over the limit was at least 10 MW over and was in the first hour of the day.

Figure B.6.2 | Energy Not Served for St. Mary's MTS and Tarentorus MTS

2019

Capacity Need (MW)																								
90																								
80																								
70											0.02%							0.02%	0.02%	0.02%	0.02%			
60								0.02%	0.1%	0.1%	0.05%	0.05%	0.05%	0.05%	0.05%	0.1%	0.1%	0.2%	0.2%	0.2%	0.1%	0.0%	0.0%	0.02%
50								0.4%	1%	1%	0.5%	0.3%	0.4%	0.3%	0.3%	0.4%	1%	1%	1%	1%	1%	0.5%	0.1%	0.05%
40	0.2%	0.1%	0.1%	0.1%	0.1%	0.2%	1%	1%	1%	2%	1%	1%	1%	1%	1%	1%	2%	3%	3%	3%	2%	2%	1%	0.5%
30	1%	1%	1%	1%	1%	1%	2%	3%	3%	3%	2%	2%	2%	2%	2%	2%	3%	3%	4%	4%	4%	3%	3%	2%
20	3%	2%	2%	2%	2%	3%	4%	4%	4%	3%	3%	3%	3%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	3%
10	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%	4%	3%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
0	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%
HOUR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

2040

Capacity Need (MW)																								
90																								
80																								
70													0.03%											
60													0.1%	0.1%	0.1%	0.03%								
50										0.1%	0.1%	0.2%	0.4%	0.4%	0.2%	0.2%	0.2%	0.03%						
40									0.2%	0.4%	1%	1%	1%	1%	1%	1%	1%	1%	0.3%	0.03%				
30	0.03%					0.03%	0.2%	0.4%	1%	1%	2%	2%	2%	2%	2%	2%	2%	2%	1%	1%	0.4%	0.3%	0.2%	0.1%
20	0.3%	0.3%	0.3%	0.3%	0.3%	0.5%	1%	1%	2%	3%	3%	3%	3%	3%	3%	3%	3%	3%	3%	2%	2%	1%	1%	1%
10	2%	2%	1%	1%	2%	2%	2%	3%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	4%	3%	3%	3%	2%
0	4%	3%	3%	3%	4%	4%	4%	4%	4%	4%	4%	4%	5%	4%	4%	5%	5%	4%	5%	5%	5%	4%	4%	4%
HOUR	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24

Appendix C. Options and Assumptions

C.1 Economic Assumptions

An economic analysis was performed in order to compare the relative net present value ("NPV") of the feasible IRRP alternatives, including the lowest cost generation option that could meet the characteristics of the need and transmission options. The relative performance of the option (or combination of options) NPVs informs the identification of the most cost-effective options for meeting the region's needs.

Local Generation

The least-cost local generation alternative that could meet the characteristics of the region's needs is a new combined cycle gas turbine (CCGT) together with continued participation of existing demand response resources; the estimated NPV of this 65 MW generator is $250 Million. A local generator sited strategically in the 115 kV system could technically meet the reliability needs identified in the region, including the thermal overload of 115 kV circuit Sault No.3 and to prevent arming of load following the PxG contingencies. However, the cost of implementing this alternative exceeds the sum of the individual transmission solutions being recommended as part of this plan. However, such an alternative should continue to be considered as part of the IESO's Northeast Bulk Planning Study which will consider the thermal overload of the Sault No.3.

The following is a list of the assumptions made in the economic evaluation for the local CCGT option:

- The NPV of the cash flows is expressed in 2020 $CAD.
- The NPV analysis was conducted using a 4% real social discount rate (SDR). An annual inflation rate of 2% is assumed.
- An CCGT was identified as the least-cost resource alternative. The estimated levelized capacity cost assumed is about $313/kW-yr (2020 $CAD), based on escalating values from a previous study independently conducted for the IESO. The selection of this option for comparison to the transmission alternative did not account for potential operational issues that may arise during planned maintenance activities or forced outages to the unit. The life of the CCGT was assumed to be 30 years.
- Natural gas prices were assumed to be an average of $4/MMBtu throughout the study period.
- The USD/CAD exchange rate was assumed to be 0.78 for the study period.
- Carbon pricing assumptions are similar to the assumptions in the Annual Planning Outlook (i.e. carbon pricing is calculated based on the Output Based Performance Standards. This comes out to $0.00421/kg CO_2e in 2023, growing to $0.02524/kg CO_2e in 2040).
- System capacity value was $141k/MW-yr (2020 CAD) based on the CA reference price.
- The DR values was 49k/MW-yr (2020 CAD) based on the average Northeast summer and winter DRA clearing prices from 2018-2020.

Enable Remote Arming for P21G+P22G in GLP Instantaneous Load Rejection Scheme

The estimated NPV of total costs to enable remote arming of load in the existing GLP load rejection scheme for the loss of P21G and P22G circuits is $50,000. While the scheme can be manually armed, the enabling of remote arming of load will allow IESO Control Room to arm load remotely, thus eliminating the need for the manual arming sequence and making the load rejection arming procedure more efficient.

Automate Patrick St TS Manual Load Shedding Scheme

The estimated NPV of automating the manual load-shedding scheme at Patrick St TS is $2 Million. There is an existing Patrick St TS Manual load shedding scheme designed to manage the load at Patrick St TS. Loads at Patrick St TS are normally supplied by the three 115 kV Algoma circuits and from Clergue GS and load displacement generators at Algoma Steel Inc. Following contingencies that leave only one Algoma circuit in service, manual load shedding may be required. Since this process is not instantaneous, it also exposes the remaining Algoma circuit to an extremely high flow if the second circuit was to trip during the manual load shedding sequence. This scheme was originally designed as an interim solution until a more permanent solution was employed. The automated scheme must also be expanded to arm load for the Patrick St TS 214 BKF.

Appendix D. Planning Study Results

East Lake Superior Region

Study Report

ieso
Connecting Today.
Powering Tomorrow.

Table of Contents

1. Overview

The East Lake Superior (ELS) region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary's River and St. Joseph Channel to the south.

The load in this area is comprised of primarily industrial, commercial and residential which peaks in the winter. Figure 1 shows the seasonal peak loading in the region over the period of five years from 2014-2018. The majority of the load is concentrated in and around the city of Sault Ste. Marie.

Figure 1 | Seasonal Peak Demand for ELS Region

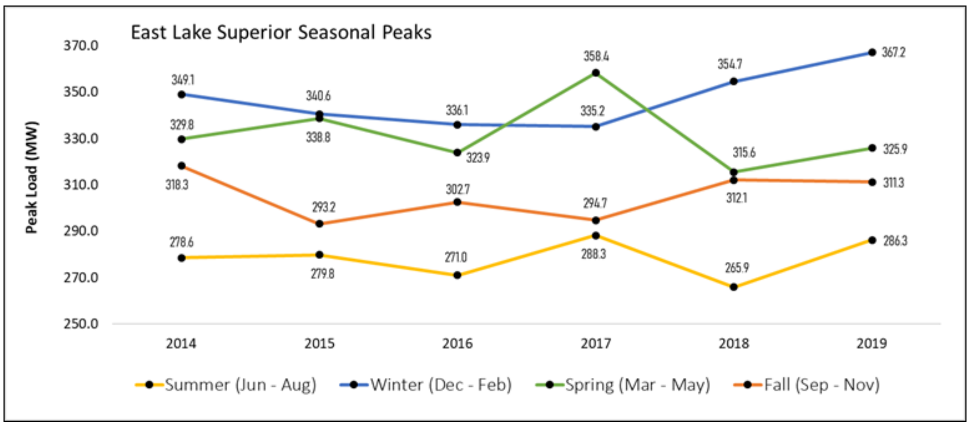
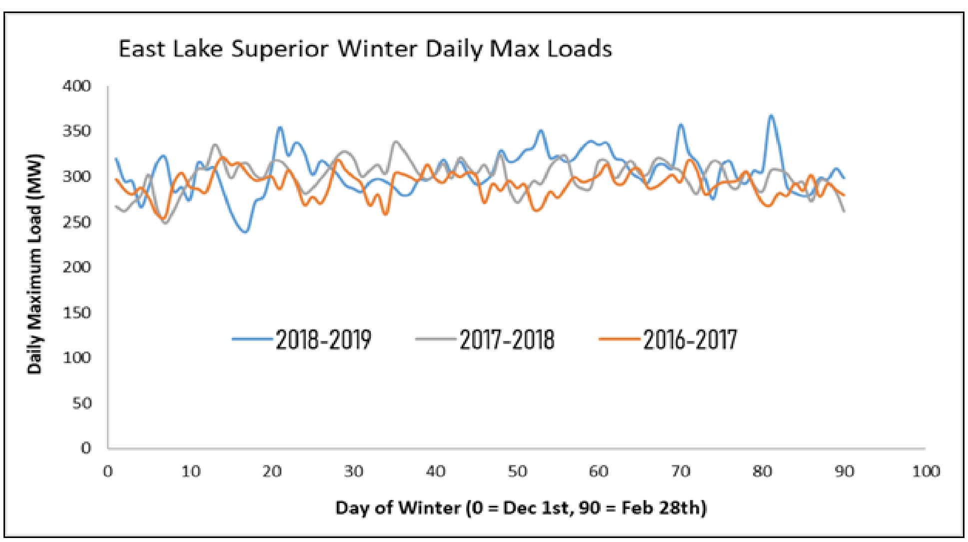


Figure 2 shows the daily winter peak load for the region from the period 2016-2019. This shows the load profile in the area is fairly flat over the winter months hovering within 10% of the peak load.

Figure 2 | Historical Daily Winter Peak Demand



Electrical supply to the region is provided through 230/115 kV autotransformers at Third Line TS, Wawa TS and MacKay TS, as well as the 230 kV and 115 kV transmission lines and step-down transformation facilities shown in Figure 3. The region is defined electrically by the 230 kV transmission circuits bounded by Wawa TS to the northwest and Mississagi TS to the southeast.

The 230 kV transmission facilities in this area provide both regional system and bulk system functions. That is, in addition to supplying local customers, they form part of an integrated network that enables the bulk transfer of electricity across the province.

The region has over 1,200 MW of generation, including numerous hydroelectric facilities, solar and wind farms and thermal generating facilities. The transmitters in the region are Hydro One Sault Ste. Marie LP (HOSSM) and Hydro One Networks Inc. (Hydro One); the local distribution companies (LDCs) are Algoma Power Inc., Chapleau PUC, Hydro One Distribution and PUC Distribution Inc.

The single line diagram of this region is shown Figure 3 and the geographical transmission map is shown is Figure 4.

Figure 3 | East Lake Superior Single Line Diagram

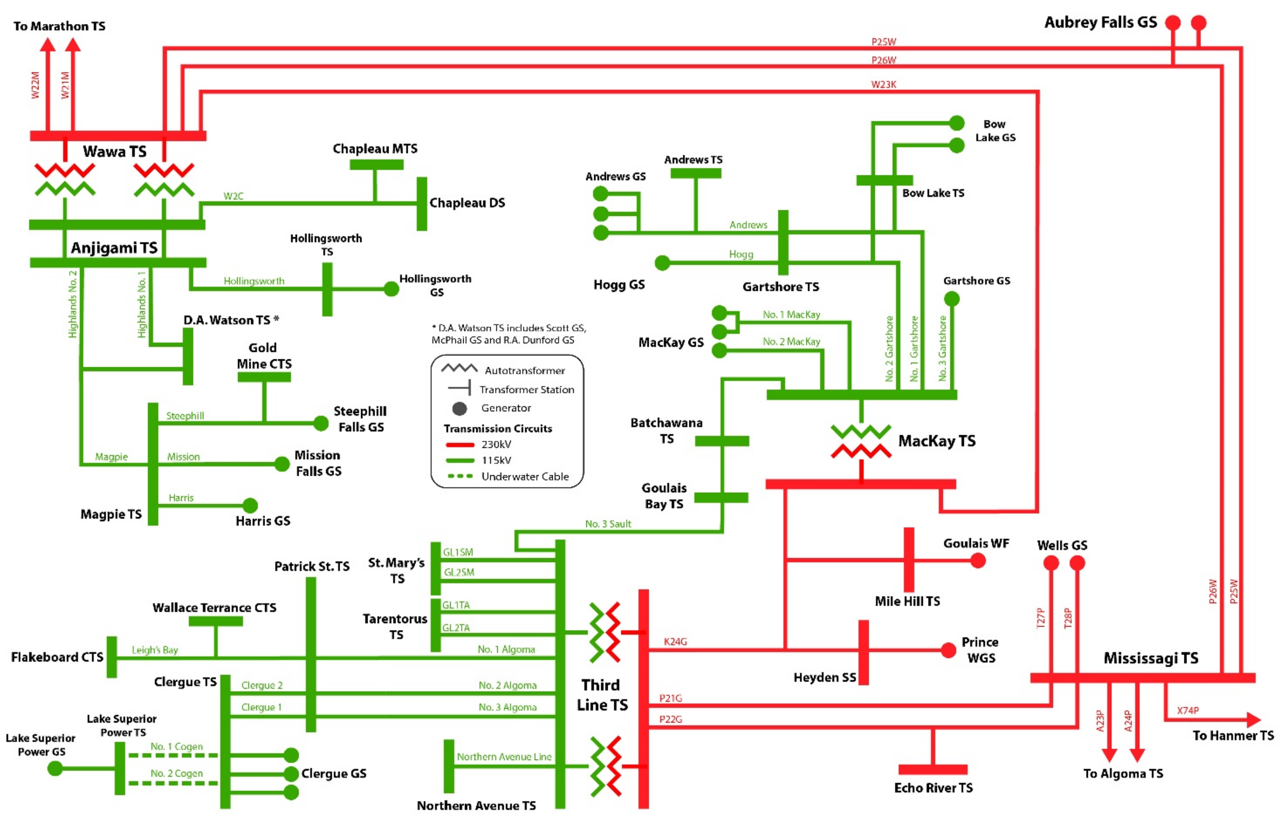
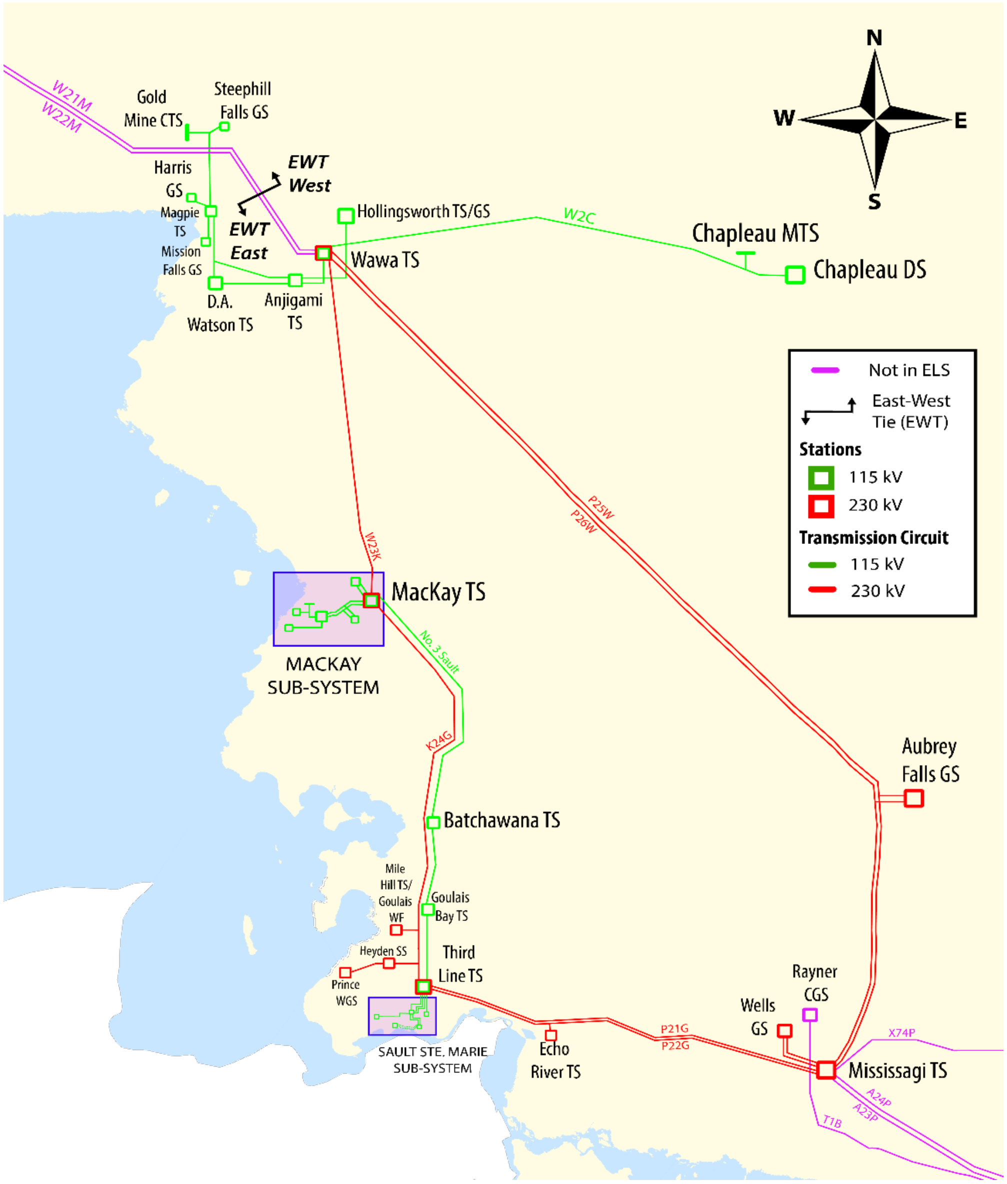


Figure 4 | East Lake Superior Transmission System



1.1 Load Forecast

Load forecast is as provided by the participating LDCs. In this region, the historical peak demand growth has been flat (neither increasing nor decreasing). For assessments concerning the regional transmission system, the non-coincident peak demand was used as a conservative approach, except for PUC Distribution Inc.'s stations where co-incident peak demand is used due to their ability to transfer loads between St. Mary's TS and Tarentorus TS during peak demand. Assessments of station-level adequacy used the same non-coincident forecast. This station level forecast snapshot for years 2020, 2025, 2030, and 2040 (end of planning horizon) is provided in Table 1 below.

Where needs are identified in the near term to medium term, further studies will be performed to refine the need using interim year forecast values to determine more precisely the load level and/or year the need arises.

Where appropriate, hourly load profiles may also be developed to aid in the evaluation of alternative such as non-wires options. The load forecast for industrial loads will be based on the information provided by individual load customers, historical hourly demand, information provided by LDCs, or other sources.

A load's power factor of 0.9 lagging is assumed at the Designated Metered Point. If voltage issues are discovered in the assessment, power factor sensitivities will be tested.

Table 1 | Station Load Forecast for ELS Region by LDC

Station	LDC	2020	2025	2030	2040
Chapleau DS	H1-SSM	6.4	9.6	9.6	9.6
St Mary's TS and Tarentorus TS	SSM PUC	116.1	112.3	111.1	112.2
Andrew TS	Algoma Power	0.2	0.2	0.2	0.2
Northern Ave TS	Algoma Power	3.2	3.3	3.4	3.6
Anjigami TS /Hollingsworth TS	Algoma Power	13.7	51.6	51.9	52.4
Mackay TS	Algoma Power	0.04	0.04	0.04	0.04
Echo River TS	Algoma Power	14.3	14.8	15.0	15.8
DA Watson TS	Algoma Power	8.6	8.9	9.2	9.6
Batchawana TS	Algoma Power	1.8	1.9	1.9	2.0
Goulais TS	Algoma Power	8.6	9.5	9.7	10.1

1.2 Local Generation Assumptions

Transmission connected local generation facilities are tabulated in Table 2. Distribution connected generation facilities, are considered load modifiers and therefore, their output is reflected as a net reduction in load as described in Appendix B of the IRRP Appendices.

Capacity assumptions in the basecase consider the amount of generation that is dependable for the majority of the time. For the hydroelectric facilities, their capacity is taken as the output that is coincident with the region's overall 98% dependable hydroelectric output.

The dependable generation output at each facility is represented by the minimum number of generator units required to produce that power. Furthermore, any units available to provide condensing services were modeled in accordance with their latest Reactive Support and Voltage

Control (RSVC) contracts. This ensures that reactive power support is reasonably, but conservatively estimated.

The wind generation facilities were modelled based on their summer and winter capacity contribution factors as per IESO's Reliability Outlook, multiplied by their peak capacity.

Table 2 | Local 98% Dependable Generation Capacity

Station	Fuel	Winter	Summer
Andrews	Hydro	0.03	0.09
Clergue	Hydro	41.86	34.02
DA Watson	Hydro	12.76	3.60
Gartshore	Hydro	0.01	0.06
Harris	Hydro	1.98	0
Hogg	Hydro	0.01	0.06
Hollingswoth	Hydro	3.21	1.50
Mackay	Hydro	0.03	0.12
Mission Falls	Hydro	2.55	0
Steephills	Hydro	1.79	0
Prince Wind Farm	Wind	5.44	1.85
Bow Lake	Wind	3.01	1.36
Goulais Wind	Wind	0	0.78

1.3 Major Interface Flows

Table 3 shows the major interfaces that impact this region. The interface flow assumptions are based on the maximum transfer capability of each interface. The baseline assumption will be to assume interface flows at ~95% of their transfer capability to ensure that load growth in the area does not penalize transfer capability in this region.

Table 3 | System Interface Flows

Interface	Definition	Transfer Capability (MW)	Interface Assumption (MW)
GLP-Inflow	MW Flow west at Mississagi TS on P21G and P22G plus MW flow into Third Line TS on K24G	295	280
East West Tie West (EWTW)	MW flow west at Wawa TS on W21M and W22M	350 (450 after 2022	332 (450 after 2022)
East West Tie East (EWTE)	MW flow east at Wawa TS on W21M and W22M	325 (450 after 2022)	309 (450 after 2022)

1.4 Monitored Circuits and Sections

Table 4 shows the winter and summer ratings for circuits and their corresponding circuit sections that will be monitored in this region. These ratings are derived from Hydro One's Power System Database (PSDb).

Table 4 | Monitored Circuits and Ratings

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
W23K-1	Wawa TS	MacKay JCT	1420	1720	2000	1220	1570	1860
W23K-2	MacKay JCT	MacKay TS	1459	1459	2000	1255	1255	1945
K24G-1	Third Line TS	Heyden JCT	1459	1459	2000	1255	1255	1945
K24G-2	Heyden JCT	Mile Hill JCT	1459	1459	2000	1255	1255	1945
K24G-3	Mile Hill JCT	MacKay TS	1459	1459	2000	1255	1255	1945
K24G-4	Heyden JCT	Heyden CTS	1459	1459	2000	1255	1255	1945
K24G-5	Mile Hill JCT	Mile Hill CTS	1459	1459	2000	1255	1255	1945
P21G-1	Mississagi TS	P21G POLE 6 JCT	1115	1115	1200	954	954	1064
P21G-2	P21G POLE 6 JCT	Third Line TS	1115	1115	1200	954	954	1064
P22G-1	Mississagi TS	Echo River TS	1115	1115	1200	954	954	1064

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
P22G-2	Echo River TS	Third Line TS	1115	1115	1200	954	954	1064
P25W-1	Mississagi TS	Aubrey Falls JCT	1020	1130	1190	880	1010	1070
P25W-2	Aubrey Falls JCT	Wawa TS	1020	1020	1020	880	880	880
P25W-3	Aubrey Falls JCT	Aubrey Falls CGS	1020	1130	1190	880	1010	1070
P26W-1	Mississagi TS	Aubrey Falls JCT	1020	1130	1190	880	1010	1070
P26W-2	Aubrey Falls JCT	Wawa TS	1020	1020	1020	880	880	880
P26W-3	Aubrey Falls JCT	Aubrey Falls CGS	1020	1130	1190	880	1010	1070
Sault No.3-1	Third Line TS	Goulais Bay TS	200	200	200	200	200	200
Sault No.3-2	Goulais Bay TS	Batchawana TS	200	200	200	200	200	200
Sault No.3-3	Batchawana TS	MacKay TS	200	200	200	200	200	200
Sault No.3-4	Goulais Bay TS	Goulais Bay TS	600	600	600	600	600	600
Sault No.3-5	Batchawana TS	Batchawana TS	600	600	600	600	600	600
GL1TA	Third Line TS	Third Line JCT #1	784	784	784	672	672	672
GL2TA	Third Line TS	Third Line JCT #1	784	784	784	672	672	672
GL1SM	Third Line TS	Third Line JCT #2	784	784	784	672	672	672
GL2SM	Third Line TS	Third Line JCT #2	784	784	784	672	672	672
W2C-1	Wawa TS	Chapleau JCT	320	360	360	280	320	320
W2C-3	Chapleau JCT	Chapleau DS	320	380	420	280	350	390
W2C-4	Chapleau JCT	Chapleau DS	320	380	420	280	350	390
W2C-5	Chapleau JCT	Chapleau MTS	370	440	490	320	400	460
No.1 Algoma	Third Line TS	Patrick St CTS	627	627	681	538	538	578
No.2 Algoma	Third Line TS	Patrick St CTS	784	784	887	672	672	751

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
No.3 Algoma	Third Line TS	Patrick St CTS	784	784	887	672	672	751
Northern Avenue	Third Line TS	Northern Avenue TS	784	784	847	672	672	720
No. 1 Clergue	Patrick St CTS	Clergue TS	627	627	660	538	538	562
No. 2 Clergue	Patrick St CTS	Clergue TS	627	627	660	538	538	562
Leigh's Bay	Patrick St CTS	Wallace Sub CTS	837	837	898	717	717	763
Leigh's Bay	Wallace Sub CTS	Flakeboard CTS	837	837	898	717	717	763
No. 1 MacKay	MacKay TS	MacKay CGS	627	627	660	538	538	562
No. 2 MacKay	MacKay TS	MacKay CGS	627	627	660	538	538	562
No. 1 Gartshore	MacKay TS	Bow Lake JCT #2	627	627	660	538	538	562
No. 1 Gartshore	Bow Lake JCT #2	Gartshore SS	627	627	660	538	538	562
No. 2 Gartshore	MacKay TS	Bow Lake JCT #2	627	627	660	538	538	562
No. 2 Gartshore	Bow Lake JCT #2	Gartshore SS	627	627	660	538	538	562
Andrews	Andrews JCT #2	Andrews TS	365	365	365	313	313	313
Hogg	Gartshore SS	Hogg CGS	414	414	414	355	355	355
No. 3 Gartshore	Gartshore SS	Gartshore CGS	627	627	660	538	538	562
Hollingsworth	Anjigami TS	Anjigami JCT #2	541	541	561	464	464	479
No. 1 High Falls	Anjigami TS	DA Watson TS	627	627	627	464	464	479

Circuit	From	To	Winter Cont (A)	Winter LTR (A)	Winter STE (A)	Summer Cont (A)	Summer LTR (A)	Summer STE (A)
No. 2 High Falls	Anjigami JCT	DA Watson TS	490	490	490	420	420	420
Magpie	DA Watson TS	Magpie SS	784	784	847	672	672	720
Steephill	Magpie SS	River Gold JCT	627	627	660	538	538	562
Harris	Magpie SS	Harris CGS	627	627	660	538	538	562
Mission	Magpie SS	Mission Falls CGS	627	627	660	538	538	562

1.5 Special Protection Schemes

Table 5 | Relevant Remedial Action Schemes (RAS)

Facility	Description
Third Line TS	a) GLP Instantaneous Load Rejection Scheme, b) Northwest Load Rejection Scheme, and c) Under Voltage Sault Local Load Rejection Scheme
Mackay TS	MacKay TS – No.3 Sault 115 kV Line – Generation Rejection (G/R) Scheme

There are three existing Remedial Action Schemes (RASs) located at Third Line TS: a) GLP Instantaneous Load Rejection Scheme, b) Northwest Load Rejection Scheme and c) Under Voltage Sault Local Load Rejection (L/R) Scheme. The GLP Instantaneous Load Rejection Scheme have six load blocks that can be armed and shed 115kV connected load for either the loss of both Third Line transformers or the loss of both P21G and P22G. The Northwest Load Rejection Scheme can be armed for the automatic load rejection which will be initiated from Mississagi TS for the loss of both A23P and A24P in "MISS x ALG Zone", or S22A or X27A in the "ALG x SUD Zone". Five protective relays (R1 to R5) control the arming of five load blocks (Load Block 1 to Load Block 5) of the Northwest Load Rejection Scheme, which are armed in a preferred order to minimize impact on certain critical loads such as hospitals. The Under Voltage Sault Local Load Rejection (L/R) Scheme is designed to shed loads connected to the 115kV side of Third Line TS in the event of the voltage dropping below a setpoint. This setpoint is currently set at 108kV. This scheme uses the same six load blocks in GLP Instantaneous Load Rejection Scheme.

The primary purpose of the MacKay TS – Sault No.3 115 kV circuit – Generation Rejection (G/R) Scheme is to ensure the post-contingency load on No.3 Sault 115 kV circuit is within its continuous rating for loss of T2 230/115 kV autotransformer at MacKay TS or for the loss of K24G 230 kV line between MacKay TS and Third Line TS under specific transmission system conditions.

The scheme is expected to be armed when Sault No.3 circuit is operated in parallel with the normal 230 kV system and the following conditions exist:

1) The total generation flow out of MacKay TS exceeds the continuous rating of the Sault No.3 circuit which will result in a post contingency flow above the continuous rating for the loss of T2 including the 115 kV NORTH BUS and 230 kV T2H BUS or

2) East-West system flows are high in the east direction and GLP system generation is high which will result in a post contingency flow above the continuous rating of Sault No.3 for loss of K24G 230 kV circuit.

2. Credible Scenarios and Planning Events

The following sections below outline the scenarios and contingencies that have been assessed. For practical purposes, recognizing the level of precision of demand forecasts, the study will initially focus on analyzing scenarios and contingencies for the conditions in the following years; 2025 (to represent the near-term planning horizon), 2030 (to represent the medium-term planning horizon), and 2035 and 2040 (to represent the long-term planning horizon).

2.1 Studied Scenarios

Table 6 describes the various scenarios that were studied in this regional planning cycle. In addition, high industrial growth around the proposed Limer TS was also included as a sensitivity analysis. Limer TS is a newly proposed 115/44kV transformer station which will be connected between Hollingsworth TS and Anjigami TS to support the proposed load growth in this sub-region. This was applied to the most limiting contingencies found in the scenarios below. The results in this report reflect that sensitivity.

Table 6 | Scenarios to be Assessed

Scenario Name	Scenario Type	Scenario Description
Scenario 1	Winter peak, extreme weather, long-range forecast	• Dependable winter generation • Bulk transfer at 5% less than TTC • East West Transfer flowing east
Scenario 2	Winter peak, extreme weather, long-range forecast	• Dependable winter generation • Bulk transfer at 5% less than TTC • East West Transfer flowing west
Scenario 3	Summer peak, extreme weather, long-range forecast	• Dependable summer generation • Bulk transfer at median historical levels • East West Transfer flowing east
Scenario 4	Summer peak, extreme weather, long-range forecast	• Dependable summer generation • Bulk transfer at median historical levels • East West Transfer flowing west
Scenario 5	Median low-demand	• Dependable winter generation • Bulk transfer at median historical levels • East West Transfer flowing west

Table 7 describes the various types of Planning Events that were simulated while conducting the studies in this regional plan.

Table 7 | Contingencies Assessed

Pre-Contingency State	Contingency
All Elements In-Service	[Single Element Contingencies (N-1)]
All Elements In-Service	[Common Tower Contingencies (N-2)]
All Elements In-Service	[Breaker Failure Contingencies (N-2)]
[One Element] Out-of-service	[Single Element Contingencies (N-1-1)]
One generating unit out-of-service	Single Element Contingencies (N-G-1)

2.2 Studied Contingencies

Table 8 | Studied Single Contingencies

P21G	P22G	P25W	P26W	W23K	K24G	No 3 Sault	W2C	Northern Ave.
No.1 Algoma	No.2 Algoma	No.3 Algoma	Mississagi A- bus*	Mississagi K-bus*	No.1 Clergue	No.2 Clergue	GL1SM	GL2SM
GL1TA	GL2TA	No.1 Gartshore	No.2 Gartshore	No.1 High Falls	No.2 High Falls	Third Line T1	Third Line T2	Leigh's Bay
No.1 Mackay	No.2 Mackay	No.3 Gartshore	Andrews	Hogg	Hollingsworth	Magpie	Steephill	Harris
Mission	Anjigami T1	Hollingsworth T2						

*Bus contingencies are only simulated for the All-in-service scenario

Table 9 | Studied Double Contingencies

P21G+P22G	P25W+P26W	No.1 Algoma+No.2 Algoma	Patrick St 214 BKF	Third Line 402 BKF	Third Line 408 BKF
Mississagi AL25 BKF	Mississagi L24L25 BKF	Mississagi KL24 BKF	Mississagi L26L74 BKF	Mississagi KL74 BKF	Wawa L23L25 BKF
Wawa L21L25 BKF	Wawa HL21 BKF	Wawa AL23 BKF	Third Line 412 BKF	Third Line 405 BKF	Wawa DL1 BKF
Patrick St 205 BKF	Wawa KL2 or DL2 BKF	Wawa AH BKF	Mississagi L24L25 BKF	Mississagi L23L26 BKF	Mississagi AL23 BKF

3. Planning Criteria

The study will adhere to planning criteria in accordance with planning events and performance as detailed by:

- North American Electric Reliability Corporation ("NERC") TPL-001 "Transmission System Planning Performance Requirements" ("TPL-001"), and
- IESO Ontario Resource and Transmission Assessment Criteria ("ORTAC").

Applying ORTAC, NERC and NPCC criteria to assess supply capacity and reliability needs, the following categories of needs can be identified:

- Supply capacity requirements were assessed to analyze the capability of the system to reliably supply load in the ELS region.
- Load security describes the amount of load susceptible to supply interruptions in the event of a major transmission outage.
- Load restoration describes the electricity system's ability to restore power to those customers affected by a major transmission outage within reasonable timeframes. Restoration from a normal outage should remain under eight hours, consistent with ORTAC.
- Step-down station capacity needs were identified by comparing forecast demand growth to the station's 10 day Limited Time Rating ("LTR"), or thermal capacity, to determine the net incremental requirement for transformation capacity in the area.

3.1 Supply Capacity Requirements

3.1.1 Loss of Third Line T1/T2

Loss of one of the Third Line TS autotransformers causes the companion transformer to be loaded close to its LTR rating. This is an existing situation. Once the Sault No.3 circuit comes into service in 2023 and beyond, the loading on the remaining autotransformer is reduced.

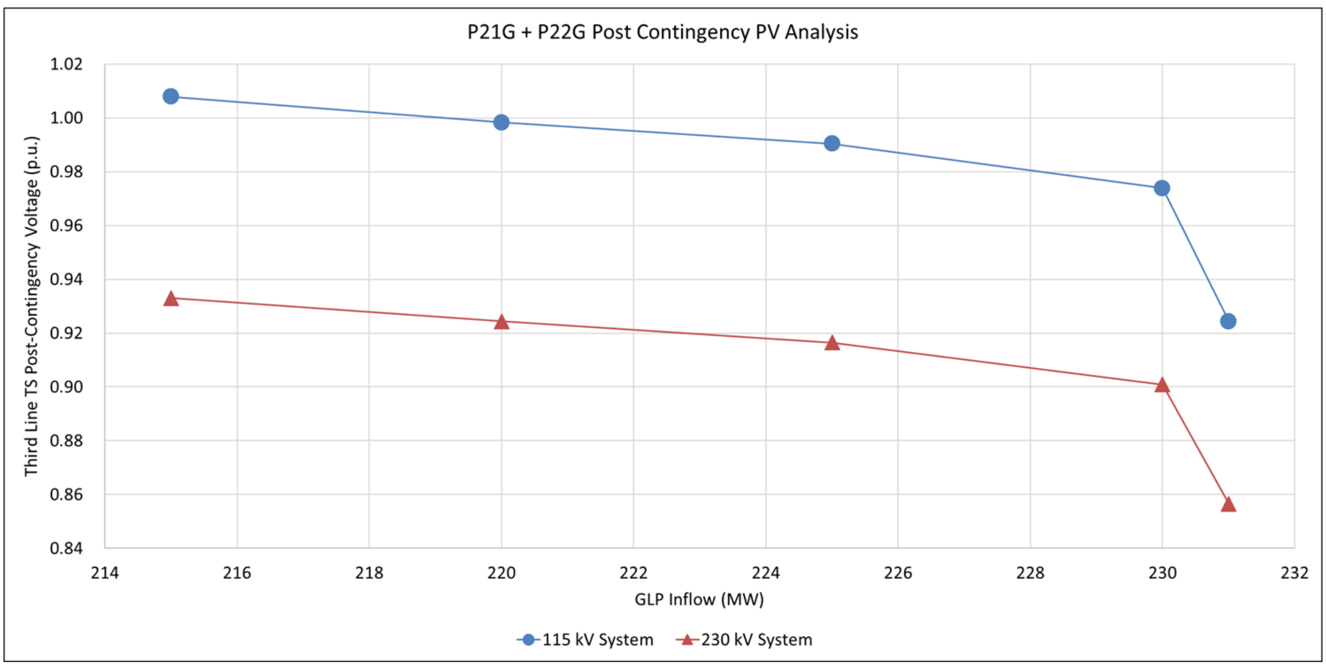
Table 10 | Third Line Autotransformer Loading Following Loss of Companion for EWTW Flow, Scenario 1

Limiting Contingency	Limiting Element	LTR Rating (MVA)	2020 Loading (MVA)	2025 Loading (MVA)	2030 Loading (MVA)	2040 Loading (MVA)
Third Line T1	Third Line T2	280	279	256	257	256

3.1.2 Loss of P21G and P22G

Loss of P21G and P22G causes voltage collapse at Third Line and other ELS stations throughout the planning period. This is illustrated in the figure below.

Figure 4 | Post Contingency PV Analysis



3.1.3 Loss of Two Algoma Circuits

Following the loss of one Algoma circuit, the loss of a second Algoma circuit would result in the remaining third Algoma circuit getting overloaded beyond its STE. The existing solution is the Patrick St Manual load shedding scheme which was designed to manage load manually to minimize the impact on the remaining Algoma circuit. However, it does not ensure the LTE rating of the remaining circuit to be respected. It was designed as an interim solution until a more permanent solution was implemented.

Table 11 | Loading on Algoma 1 Circuit Following Loss of Other Two Algoma Circuits, all Scenarios

Limiting Contingency	Limiting Element	From	To	LTE Rating (MVA)	STE Rating (MVA)	2020 Loading (MVA)	2025 Loading (MVA)	2030 Loading (MVA)	2040 Loading (MVA)
Algoma No. 2 + Algoma No. 3	Algoma No. 1	Third Line TS	Patrick St TS	627	681	727	756	774	767

3.1.4 Patrick St 214 BKF

A Breaker Failure (BKF) of the 214 breaker at Patrick St TS results in the loss of two out of the three 115 kV circuits from Third Line TS to Patrick St TS, resulting in the remaining Algoma No. 1 circuit overloaded beyond its STE rating for all years. This is also shown in Table 11 above.

3.1.5 No. 3 Sault Line Overload

During a P25W or P26W outage, a K24G contingency results in thermal overload of Sault No.3 circuit beyond its upgraded STE ratings starting in 2023.

Table 12 | Loading on No.3 Sault Circuit Following a PxW Outage and K24G Contingency, Scenario 2

Outage	Limiting Contingency	Limiting Element	From	To	LTE Rating (Amps)	STE Rating (Amps)	2020 Loading (Amps)	2025 Loading (Amps)	2030 Loading (Amps)	2040 Loading (Amps)
PxW	K24G	No. 3 Sault	Thid Line TS	Goulais Bay TS	541	561	N/A	658	718	734
PxW	K24G	No. 3 Sault	Goulais Bay TS	Batchawana TS	541	561	N/A	620	670	683
PxW	K24G	No. 3 Sault	Batchawana TS	Mackay TS	541	561	N/A	613	660	672

In addition, when one of the Third Line TS autotransformers is initially experiencing an outage, Sault No.3 circuit will need to be in-service (after its proposed upgrades) in order to prevent overloading of the companion Third Line TS autotransformer. However, if the second autotransformer is also lost, Sault No.3 circuit will be overloaded beyond its upgraded STE rating and cause a voltage collapse in the area served by Third Line TS.

3.1.6 Hollingsworth T1 and T2 Overload

For loss of Anjigami TS, in this sub-region, there is an overload on Hollingsworth T1 and T2, starting in the year 2024. This is shown in Table 13 below. The Needs Assessment report also identified that Hollingsworth TS – Transformer T2 / Anjigami TS – Transformer T1 will become overloaded due to a large customer connecting to the 44 kV system.

The incremental growth scenario, which incorporates the addition of new industrial load in this sub-region around Limer TS worsens the need identified in Table 13 to a point that loss of Anjigami T1 results in significant voltage decline in the area.

Table 13 | Loading on Hollingsworth T1 and T2 Following Anjigami T1 Contingency, all Scenarios

Limiting Contingency	Limiting Element	LTE Rating (MVA)	STE Rating (MVA)	2020 Loading (MVA)	2025 Loading (MVA)	2030 Loading (MVA)	2040 Loading (MVA)
Anjigami T1	Hollingsworth T1	33.7	52.5	11	60	62	62
Anjigami T1	Hollingsworth T2	28	28	17	60	62	62

3.2 Step-Down Station Capacity Requirements

As shown in Table 14., there is step-down station capacity needs identified in the Anjigami/Hollingsworth sub-region within the ELS region.

Table 14 | Step-down Station Capacity Needs

Station	Cont. Rating (MVA)	LTR Rating (MVA)	2020 (MW)	2025 (MW)	2030 (MW)	2040 (MW)
Andrews TS	5.0	5.0	0.22	0.22	0.22	0.22
Batchawana TS	4.3	4.3	1.64	1.72	1.78	1.92
DA Watson TS	75.0	75.0	8.47	8.76	9.01	9.51
Echo River TS	25.0	25.0	14.05	14.46	14.79	15.61
Goulais Bay TS	15.0	15.0	8.46	8.75	8.99	9.47
Limer TS (proposed TS)	TBD	TBD	37.0	54.0	56.0	56.0
MacKay TS	0.5	0.5	0.04	0.04	0.04	0.04
Northern Avenue TS	5.0	5.0	2.48	2.56	2.64	2.78
Chapleau DS	17.05	17.05	6.37	9.62	10.07	11.32
Chapleau MTS	10	10	4.31	4.68	4.37	4.29
St Mary's MTS + Tarentorus MTS	210	210	116.11	112.30	111.09	112.21

3.3 Load Security

Load security describes the total amount of electricity supply that would be interrupted in the event of a major transmission outage. The transmission system must exhibit acceptable performance while following specified design criteria contingencies. Load security criteria, as described by ORTAC Section 7.1, specify a load interruption limit of 150 MW for single element contingencies and 600 MW for double element contingencies. A summary of the load security criteria can be found in Table 6.3 of the IRRP Report.

The demand forecast in the ELS region remains below the load security criteria outlined in ORTAC. No load security need has been identified in the planning timeframe. For single contingencies, there is no loss of load greater than 150 MW by configuration and for double contingencies, there is no loss of load greater than 600 MW.

3.4 Load Restoration

The Needs Assessment provided information on restoration challenges at Andrew TS, Batchawana TS, Goulais TS and Echo River TS. The solution to the restoration will be local to the area and will be coordinated with the transmitter and impacted LDC. Following the loss of both Third Line autotransformers and Sault No.3 circuit, the entire ELS 115 kV subsytem will be islanded. Restoration procedure from this configuration already exists and documented in the SCO. Long outage times in the Chapleau sub-region have been raised through stakeholder feedback. The IESO coordinated an investigation into the matter with Working Group members and the transmitter has confirmed that there are refurbishment and component replacement plans in place for this sub-region which could alleviate this concern. The Working Group will continue to monitor the progress of these plans.

Independent Electricity System Operator
1600-120 Adelaide Street West
Toronto, Ontario M5H 1T1

Phone: 905.403.6900
Toll-free: 1.888.448.7777
E-mail: customer.relations@ieso.ca

ieso.ca

@IESO_Tweets
facebook.com/OntarioIESO
linkedin.com/company/IESO

Connecting Today.
Powering Tomorrow.

Appendix E

Regional Infrastructure Plan

East Lake Superior

REGIONAL INFRASTRUCTURE PLAN

October 1st, 2021

(This page is intentionally left blank)

Prepared and supported by:

Company
Hydro One Sault Ste. Marie LP. (Lead Transmitter)
Hydro One Networks Inc. (Transmission)
Independent Electricity System Operator (IESO)
Hydro One Networks Inc. (Distribution)
Algoma Power Inc.
Chapleau Public Utilities Corporation
PUC Distribution Inc.

DISCLAIMER

This Regional Infrastructure Plan ("RIP") report was prepared for the purpose of developing an electricity infrastructure plan to address all near and mid-term needs identified in previous planning phases and any additional needs identified based on new and/or updated information provided by the RIP Study Team.

The preferred solution(s) that have been identified in this report may be reevaluated based on the findings of further analysis. The load forecast and results reported in this RIP report are based on the information provided and assumptions made by the participants of the RIP Study Team.

Study Team participants, their respective affiliated organizations, and Hydro One Networks Inc. (collectively, "the Authors") make no representations or warranties (express, implied, statutory or otherwise) as to the RIP report or its contents, including, without limitation, the accuracy or completeness of the information therein and shall not, under any circumstances whatsoever, be liable to each other, or to any third party for whom the RIP report was prepared ("the Intended Third Parties"), or to any other third party reading or receiving the RIP report ("the Other Third Parties"), for any direct, indirect or consequential loss or damages or for any punitive, incidental or special damages or any loss of profit, loss of contract, loss of opportunity or loss of goodwill resulting from or in any way related to the reliance on, acceptance or use of the RIP report or its contents by any person or entity, including, but not limited to, the aforementioned persons and entities.

EXECUTIVE SUMMARY

THIS REGIONAL INFRASTRUCTURE PLAN ("RIP") WAS PREPARED BY HYDRO ONE SAULT STE. MARIE LP WITH SUPPORT FROM THE RIP STUDY TEAM IN ACCORDANCE TO THE ONTARIO TRANSMISSION SYSTEM CODE REQUIREMENTS. IT IDENTIFIES INVESTMENTS IN TRANSMISSION FACILITIES, DISTRIBUTION FACILITIES, OR BOTH, THAT SHOULD BE DEVELOPED AND IMPLEMENTED TO MEET THE ELECTRICITY INFRASTRUCTURE NEEDS WITHIN THE EAST LAKE SUPERIOR REGION.

The participants of the Regional Infrastructure Plan ("RIP") Study Team included members from the following organizations:

- Algoma Power Inc. ("API")
- Chapleau Public Utilities Corporation ("Chapleau PUC")
- Hydro One Networks Inc. (Transmission)
- Hydro One Sault Ste. Marie LP. ("HOSSM")
- Hydro One Networks Inc. (Distribution)
- Independent Electricity System Operator ("IESO")
- PUC Distribution Inc. ("PUC")

This RIP is the final phase of the second cycle of East Lake Superior (ELS) regional planning process, which follows the completion of the East Lake Superior Integrated Regional Resource Plan ("IRRP") in April 2021 and the East Lake Superior Region Needs Assessment ("NA") in June 2019. This RIP provides a consolidated summary of the needs and recommended plans for East Lake Superior Region over the planning horizon (1 – 20 years) based on available information.

This RIP discusses needs identified in the previous regional planning cycle, the Needs Assessment and IRRP reports for this cycle, and wires solutions recommended to address these needs. Implementation plans to address some of these needs are already completed or are underway. Since the previous regional planning cycle, the following projects are underway or completed

- **End of life Wood Pole Replacements**: Multiple wood pole replacement projects were completed on a number of 115kV and 230kV circuits. These circuits consisted of wood pole structures that were assessed at being at their end of life and in need of replacements. The following circuits have their end of life wood pole structures replacement completed between 2014 to 2019:
    - No.2 and No.3 Algoma (completed in 2014)
    - Northern Ave 115kV circuit (completed in 2014)
    - No.1 Garshore (completed in 2015)
    - Hogg (completed in 2015)
    - P21G (completed in 2019)

- **Hwy 101 TS**: Installed a new control building completed with new protection relays, batteries, chargers, automatic transfer schemes and RTU to replace end of life components such as electro-mechanical relays and batteries. This project was completed and in-serviced in 2015.

- **Anjigami TS**: Performed electrical and civil upgrade, including the installation of a new 44kV breaker, redundant battery and chargers, and replacement of protection equipment and other end of life AC/DC system. It also includes ground grid improvements. This project was completed in 2017.

- **Echo River TS**: Improve transmission reliability with the installation of an additional 230/34.5kV 25MVA Transformer (T2) as an on-site spare. This project is underway with a targeted in-service date of 2023 Q2.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in the Table 1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 1. Recommended Plans in East Lake Superior Region over the Next 10 Years

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

[1] To coordinated with IESO's 2021 Bulk Planning Study regarding Sault No.3 Circuit Overloading

8	Patrick St. TS: End of life 115kV breaker	Replace end of life 115kV breakers ‘like for like’ per current standard	2024	$3.3M
9	Third Line TS : T2 end of life	Replace end of life T2 ‘like for like’ per current standard	2025	$16.4M
10	Northern Ave TS: end of life component replacement	Replace end of life T1 with smaller MVA unit and protection relays per current standard	2025	$2.5M
11	Anjigami/Hollingsworth TS : Transformer overload	Build new 115/44kV Station - HOSSM to work with API to continue to develop solutions	2024/2025	$30M
12	Clergue TS: End of life metal clad switch gear	Replace end of life switch gear ‘like for like’ per current standard	2026	$5.2M
13	Hollingsworth TS: End of life Protection relay	Replace end of life protection per current standard	2025	$1.1M
14	D.A. Watson TS: End of life metal clad switch gear	Replace end of life switch gear ‘like for like’ per current standard	2026	$9.2M

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 1 while keeping the Study Team apprised of project status;
- All the other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

TABLE OF CONTENTS

List of Figures

List of Tables

1 INTRODUCTION

THIS REPORT PRESENTS THE REGIONAL INFRASTRUCTURE PLAN (“RIP”) TO ADDRESS THE ELECTRICITY NEEDS OF THE EAST LAKE SUPERIOR REGION BETWEEN 2019 AND 2039.

The report was prepared by Hydro One Sault Ste. Marie LP (HOSSM) on behalf of the Study Team that consists of Hydro One Networks Inc. (Transmission), Hydro One (Distribution), Algoma Power Inc. (API), PUC Distribution Inc., Chapleau Public Utilities Corporation and the Independent Electricity System Operator (“IESO”), in accordance with the new Regional Planning process established by the Ontario Energy Board in 2013.

The East Lake Superior Region is the region extends from the town of Dubreuilville in the north to the town of Bruce Mines in the south and includes the city of Sault Ste. Marie and the township of Chapleau. The region is roughly bordered geographically by Highway 129 to the east, Highway 101 to the north, Lake Superior to the west and St. Mary’s River and St. Joseph Channel to the south as shown in Figure 1.1 below. The region is supplied from a combination of local generation and connection to the Ontario electricity grid via 230 kV transmission lines to Mississagi Transformer Station in the East, 230kV and 115 kV transmission lines to Wawa Transformer Station in the North.

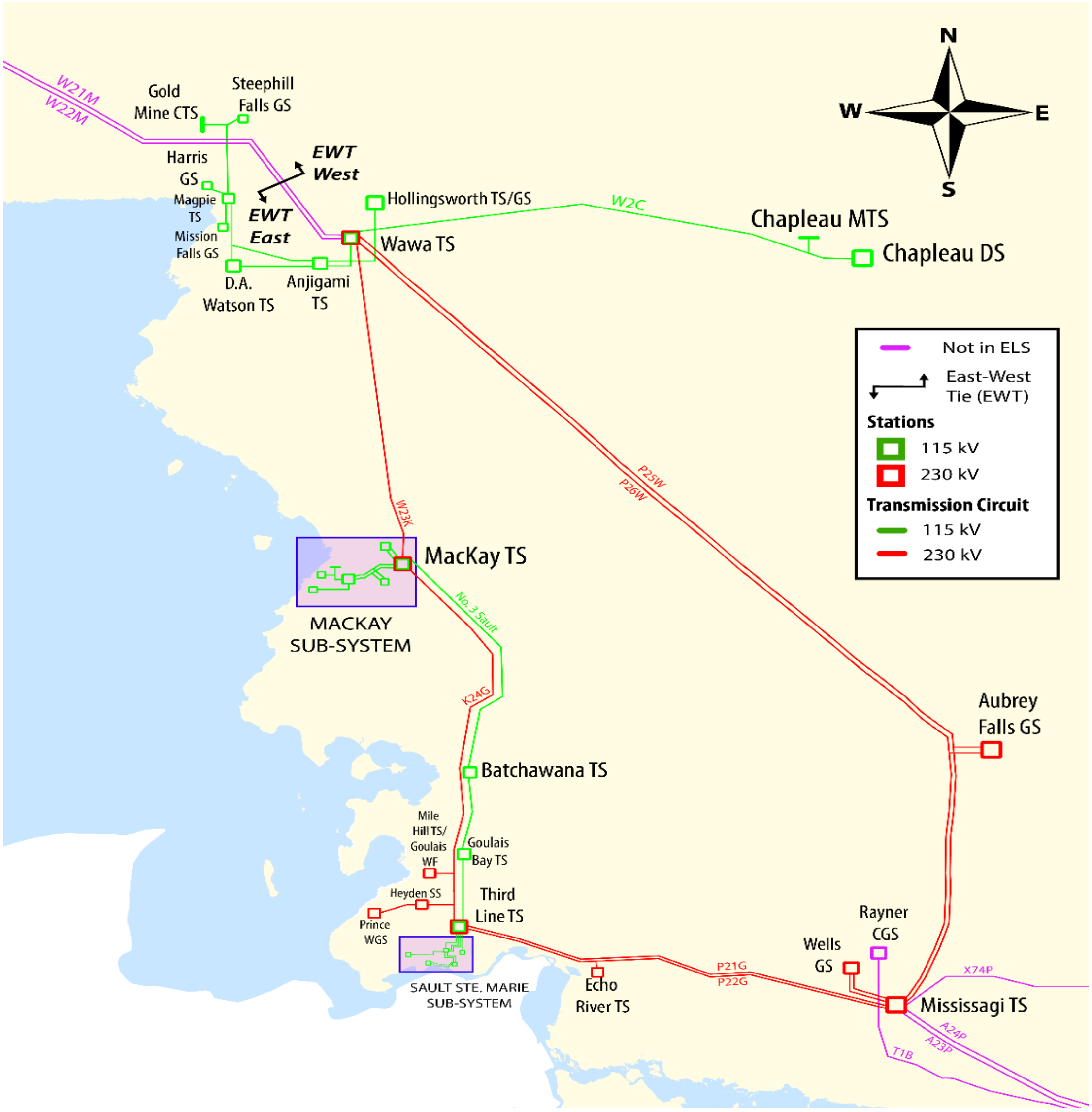


Figure 1-1: East Lake Superior Region Map

1.1 Objectives and Scope

The RIP report examines the needs in the East Lake Superior Region. Its objectives are to:

- Provide a comprehensive summary of needs and wires plans to address the needs;
- Identify any new needs that may have emerged since previous planning phases e.g., Needs Assessment ("NA"), Scoping Assessment ("SA"), and/or Integrated Regional Resource Plan ("IRRP");
- Assess and develop a wires plan to address these needs; and
- Identify investments in transmission and distribution facilities or both that should be developed and implemented on a coordinated basis to meet the electricity infrastructure needs within the region.

The RIP reviewed factors such as the load forecast, major high voltage sustainment issues emerging over the near, mid- and long-term horizon, transmission and distribution system capability along with any updates to local plans, conservation and demand management ("CDM") forecasts, renewable and non-renewable generation development, and other electricity system and local drivers that may impact the need and alternatives under consideration.

The scope of this RIP is as follows:

- A consolidated report of the relevant wires plans to address near and medium-term needs identified in previous planning phases (Needs Assessment, Scoping Assessment, and/or Integrated Regional Resource Plan);
- Discussion of any other major transmission infrastructure investment plans over the planning horizon;
- Identification of any new needs and a wires plan to address these needs based on new and/or updated information;
- Develop a plan to address any longer term needs identified by the Study Team.

1.2 Structure

The rest of the report is organized as follows:

- Section 2 provides an overview of the regional planning process.
- Section 3 describes the regional characteristics.
- Section 4 describes the transmission work completed over the last ten years.
- Section 5 describes the load forecast and study assumptions used in this assessment.
- Section 6 describes the adequacy of the transmission facilities in the region over the study period.
- Section 7 discusses the needs and provides the alternatives and preferred solutions.
- Section 8 provides the conclusion and next steps.

2 REGIONAL PLANNING PROCESS

2.1 Overview

Planning for the electricity system in Ontario is done at three levels: bulk system planning, regional system planning, and distribution system planning. These levels differ in the facilities that are considered and the scope of impact on the electricity system. Planning at the bulk system level typically looks at issues that impact the system on a provincial level, while planning at the regional and distribution levels looks at issues on a more regional or localized level.

Regional planning looks at supply and reliability issues at a regional or local area level. Therefore, it largely considers the 115 kV and 230 kV portions of the power system that supply various parts of the province.

2.2 Regional Planning Process

A structured regional planning process was established by the Ontario Energy Board ("OEB") in 2013 through amendments to the Transmission System Code ("TSC") and Distribution System Code ("DSC"). The process consists of four phases: the Needs Assessment [2] ("NA"), the Scoping Assessment ("SA"), the Integrated Regional Resource Plan ("IRRP"), and the Regional Infrastructure Plan ("RIP").

The regional planning process begins with the NA phase, which is led by the transmitter to determine if there are regional needs. The NA phase identifies the needs and the Study Team determines whether further regional coordination is necessary to address them. If no further regional coordination is required, further planning is undertaken by the transmitter and the impacted local distribution company(s) ("LDC") or customer(s) and develops a Local Plan ("LP") to address them.

In situations where identified needs require coordination at the regional or sub-regional levels, the IESO initiates the SA phase. During this phase, the IESO, in collaboration with the transmitter and impacted LDCs, reviews the information collected as part of the NA phase, along with additional information on potential non-wires alternatives, and makes a decision on the most appropriate regional planning approach. The approach is either a RIP, which is led by the transmitter, or an IRRP, which is led by the IESO. If more than one sub-region was identified in the NA phase, it is possible that a different approach could be taken for different sub-regions.

The IRRP phase will generally assess infrastructure (wires) versus resource (CDM and Distributed Generation and energy efficiency) options at a higher or more macro level, but sufficient to permit a comparison of options. If the IRRP phase identifies that infrastructure options may be most appropriate to meet a need, the RIP phase will conduct detailed planning to identify and assess the specific wires alternatives and recommend a preferred wires solution. Similarly, resource options that the IRRP identifies as best suited to meet a need are then further planned in greater detail by the IESO. The IRRP phase also includes IESO led stakeholder engagement with municipalities, Indigenous communities, business sectors and other interested stakeholders in the region.

---

[2] Also referred to as Needs Screening

The RIP phase is the fourth and final phase of the regional planning process and involves: discussion of previously identified needs and plans; identification of any new needs that may have emerged since the start of the planning cycle; and development of a wires plan to address the needs where a wires solution would be the best overall approach. This phase is led and coordinated by the transmitter and the deliverable is a comprehensive report of a wires plan for the region. Once completed, this report is also referenced in transmitter's rate filing submissions and as part of LDC rate applications with a planning status letter provided by the transmitter.

To efficiently manage the regional planning process, Hydro One has been undertaking wires planning activities in collaboration with the IESO and/or LDCs for the region as part of and/or in parallel with:

- Planning activities that were already underway in the region prior to the new regional planning process taking effect;
- The NA, SA, and LP phases of regional planning;
- Participating in and conducting wires planning as part of the IRRP for the region or sub-region;
- Working and planning for connection capacity requirements with the LDCs and transmission connected customers.

Figure 2-1 illustrates the various phases of the regional planning process (NA, SA, IRRP, and RIP) and their respective phase trigger, lead, and outcome.

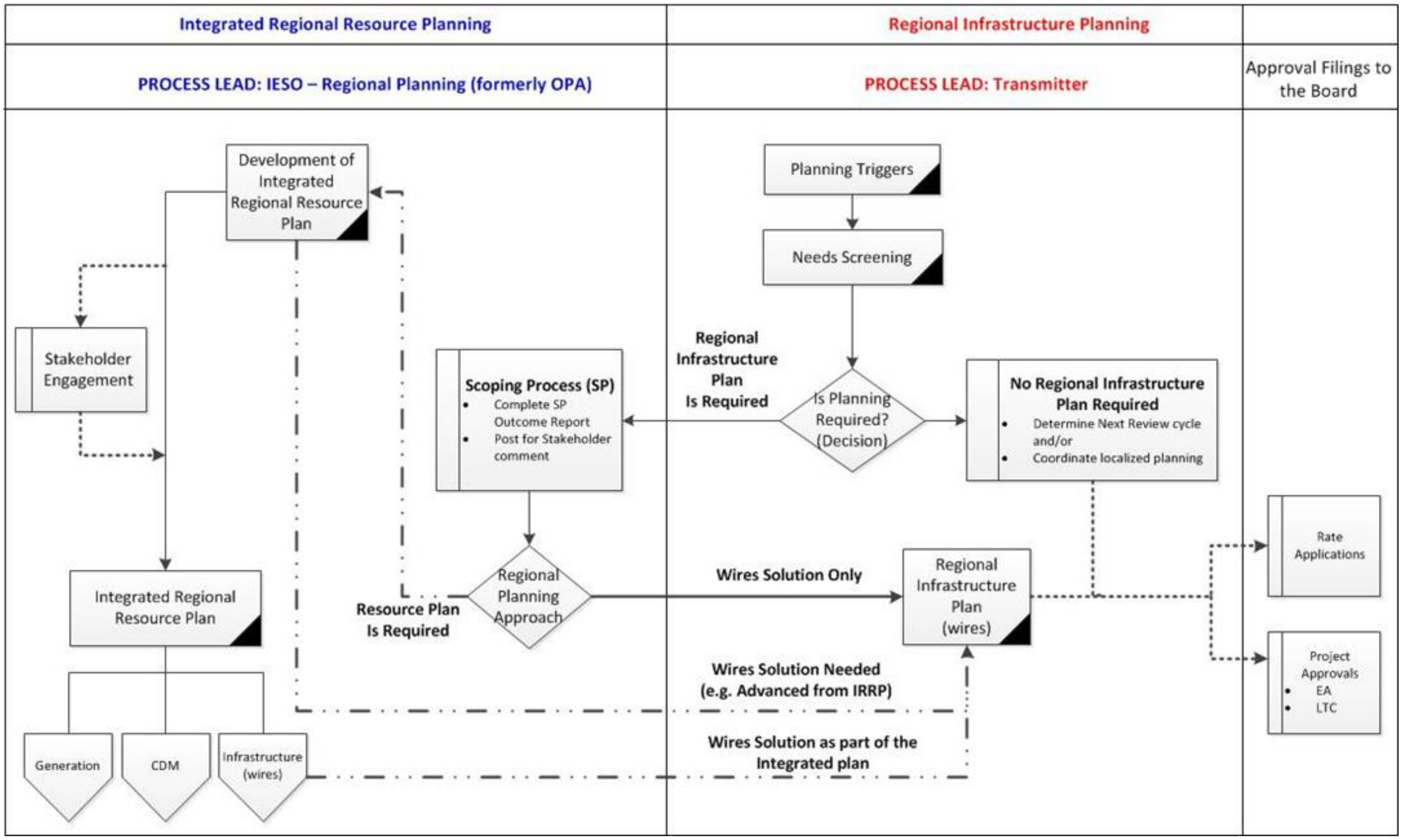


Figure 2-1: Regional Planning Process Flowchart

2.3 RIP Methodology

The RIP phase consists of a four step process (see Figure 2-2) as follows:

1) Data Gathering: The first step of the process is the review of planning assessment data collected in the previous phase of the regional planning process. Hydro One collects this information and reviews it with the Study Team to reconfirm or update the information as required. The data collected includes:
   - Net peak demand forecast at the transformer station level. This includes the effect of any distributed generation or conservation and demand management programs.
   - Existing area network and capabilities including any bulk system power flow assumptions.
   - Other data and assumptions as applicable such as asset conditions; load transfer capabilities, and previously committed transmission and distribution system plans.
2) Technical Assessment: The second step is a technical assessment to review the adequacy of the regional system including any previously identified needs. Depending upon the changes to load forecast or other relevant information, regional technical assessment may or may not be required

or be limited to specific issue only. Additional near and mid-term needs may be identified in this phase.

3) Alternative Development: The third step is the development of wires options to address the needs and to come up with a preferred alternative based on an assessment of technical considerations, feasibility, environmental impact and costs.
4) Implementation Plan: The fourth and last step is the development of the implementation plan for the preferred alternative.

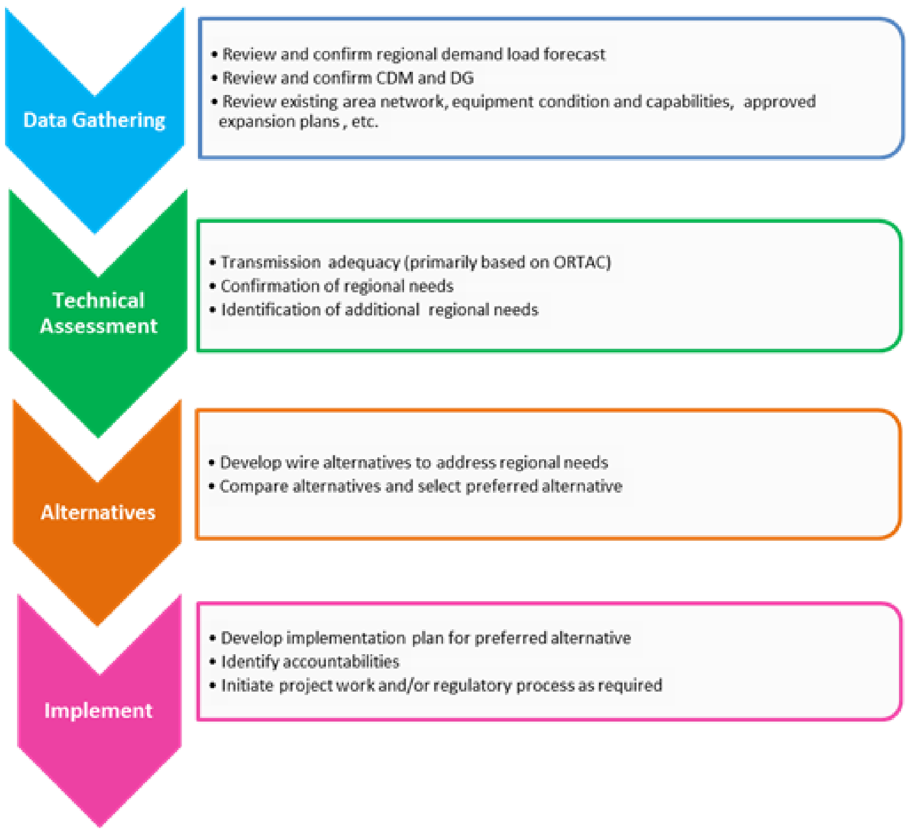


Figure 2-2: RIP Methodology

3 REGIONAL CHARACTERISTICS

THE EAST LAKE SUPERIOR REGION INCLUDES THE AREA ROUGHLY BORDERED GEOGRAPHICALLY BY TOWN OF DUBERUILVILLE AND HIGHWAY 101 TO THE NORTH AND THE TOWNSHIP OF CHAPLEAU, BRUCE MINES TO THE SOUTH AND INCLUDES THE CITY OF SAULT STE. MARIE, HIGHWAY 129 TO THE EAST, AND LAKE SUPERIOR TO THE WEST. IT CONSISTS OF THE CITY OF SAULT STE. MARIE.

The region is supplied from a combination of local generation and connections to the Ontario electricity grid via 230 kV transmission lines to Mississagi Transformer Station in the East, 230kV and 115 kV transmission lines to Wawa Transformer Station in the North. Majority of the region's electrical need is supplied through a 230/115 kV transformer station at Third Line TS. Local generation in the area consists of mainly hydroelectric and wind generation with a total installed capacity of 1039 MW in the 115 kV and 230kV networks. The East Lake Superior Region is a winter peaking region, with 2020 winter peak demand at 361MW.

PUC Distribution Inc. ("PUC") is the Local Distribution Company ("LDC") which serves the electricity demand in the City of Sault Ste. Marie. The LDC that supplies primarily rural customers – industrial, commercial, and residential customers in the aregion are API, Chapleau PUC and Hydro One Networks Inc. Distribution

Below is a description of major Transmission asset in the region:

- Third line TS is the major transmission station that connects the 115kV system within the City of Sault Ste. Marie via two 230/115kV autotransformer to the 230kV bulk electricity network.
- Mackay TS is a 230/115kV station with one 230/115kV autotransformer that connects the local 115kV network in the vicinity of Montreal River to the 230kV bulk electricity network.
- Wawa TS is a 230/115kV station with two 230/115kV autotransformer that connects the local 115kV network in the vicinity of Michipicoten River.
- 12 other Transmission stations supply the area, with 10 of them operating at 115kV, 1 operating at 230kV , 1 operating at 44kV [3]
- A total of 319 km of 230kV circuits, 232 km of 115kV circuits and 10 km of 44kV circuits interconnect transmission stations, generation customer(s), distribution customer(s) and Transmission connected load customer(s) within the region.

Table in Appendix A and B summarize Transmission station and circuits at different operating voltages and in the area. A geographical map showing the electrical facilities of the East Lake Superior Region is provided in Figure 3-1. A single line diagram showing the electrical facilities of the East Lake Superior Region is provided in Figure 3-2.

[3] The 44kV station and line is included in HOSSM's transmitter license and are deemed transmission asset by the OEB.

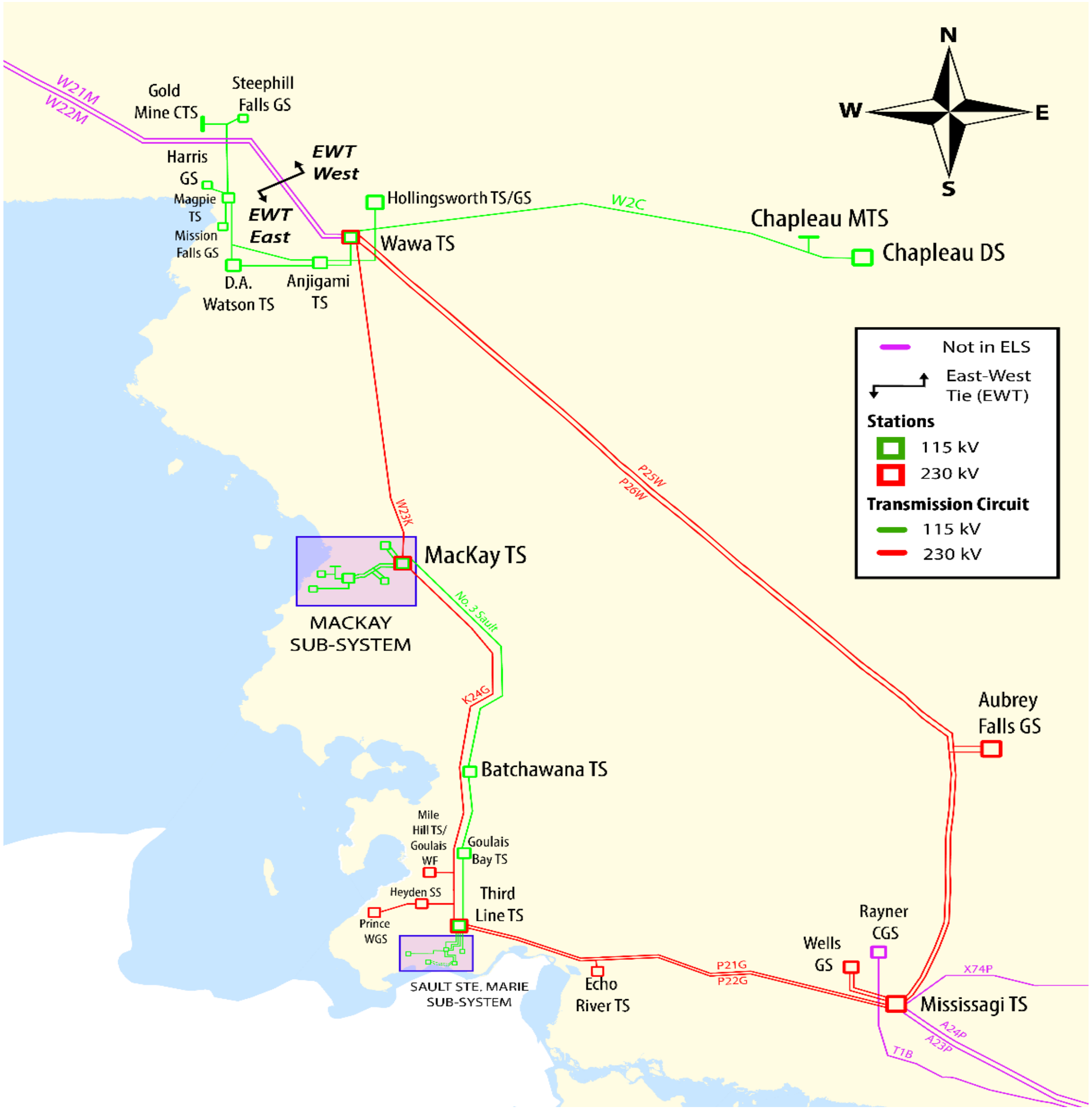


Figure 3-1: East Lake Superior Region's Transmission Network

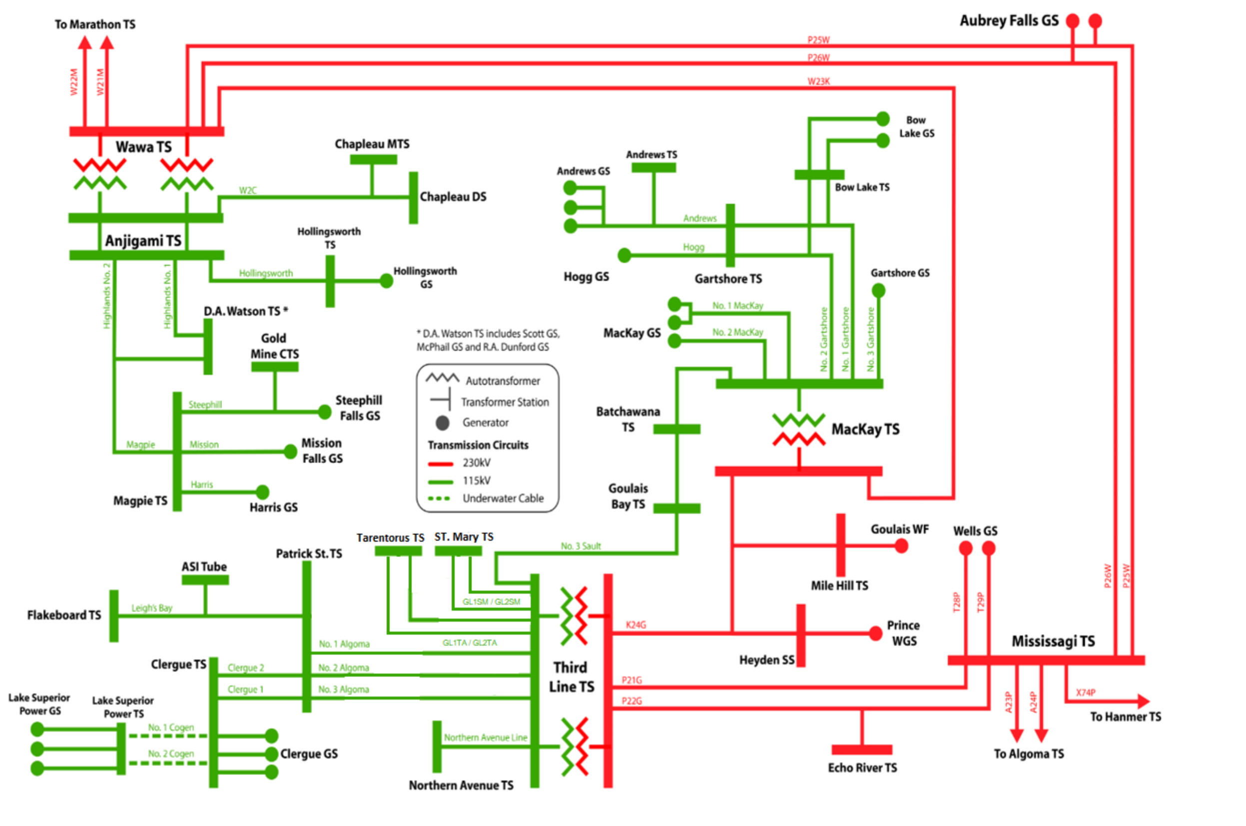


Figure 3-2: Single Line Diagram of East Lake Superior Region's Transmission Network

4 TRANSMISSION FACILITIES/PROJECTS COMPLETED AND/OR UNDERWAY SINCE LAST REGIONAL PLANNING

THE ESL REGIONS COMPLETED IT 1ST CYCLE REGIONAL PLANNING IN 2014. SINCE THAT TIME, SEVERAL \TRANSMISSION PROJECTS HAVE BEEN PLANNED AND/OR UNDERTAKEN BY HYDRO ONE SAULT STE. MARIE AIMED TO MAINTAIN THE RELIABILITY AND ADEQUACY OF ELECTRICITY SUPPLY TO THE EAST LAKE SUPERIOR REGION.

A summary and description of the major projects completed and/or currently underway since the completion of last cycle regional planning is provided below.

- **End of life Wood Pole Replacements**: Multiple wood pole replacement projects were completed on a number of 115kV and 230kV circuits. These circuits consisted of wood pole structures that were assessed at being at their end of life and in need of replacements. The following circuits have their end of life wood pole structures replacement completed between 2013 to 2019:
  - No.2 and No.3 Algoma (completed in 2014)
  - Northern Ave (completed in 2014)
  - No.1 Garshore (completed in 2015)
  - Hogg (completed in 2015)
  - P21G (completed in 2019)

- **Hwy 101 TS**: Installed a new control building completed with new protection relays, batteries, chargers, automatic transfer schemes and RTU to replace end of life components such as electro-mechanical relays and batteries. This project was completed and in-serviced in 2015.

- **Anjigami TS**: Performed electrical and civil upgrade, including the installation of a new 44kV breaker, redundant battery and chargers, and replacement of protection equipment and other end of life AC/DC system. It also includes ground grid improvements. This is completed in 2017.

- **Echo River TS**: Improve transmission reliability with the installation of an additional 230/34.5kV 25MVA Transformer (T2) as an on-site spare. This project is underway and have a targeted in-service date of 2023 Q2.

5 LOAD FORECAST AND STUDY ASSUMPTIONS

5.1 Load Forecast

The LDCs provided load forecasts for all the stations supplying their loads in the East Lake Superior region for the 20-year study period during the IESO led IRRP phase of regional planning. The net extreme weather corrected winter load forecast was produced by modifying the LDC forecast provided for each station to reflect extreme weather conditions and subtracted the estimated peak demand impacts of provincial conservation policy and committed Distributed Energy Resource (DER) that may have been contracted through previous provincial programs such as the Feed-in Tariff (FIT) and micro FIT program.

The electricity demand in the East Lake Superior Region is anticipated to stay flat over the next 20 years, with a peak of 348W in 2031. Figure 5-1 shows the East Lake Superior Region's Winter peak net load forecast developed during the East Lake Superior IRRP process. This IRRP forecast was used to determine the loading that would be seen by transmission lines and autotransformer stations and to identify the need for additional line and auto-transformation capacity. The IRRP non-coincident load forecasts for the individual stations in the East Lake Superior Region is given in Appendix D, Table D-1 and Table D-2. This forecast does not included a high industrial growth or expansion scenario, which will be studied as part of the IESO's bulk planning study in 2021 given the impact to the bulk transmission network in the broader region

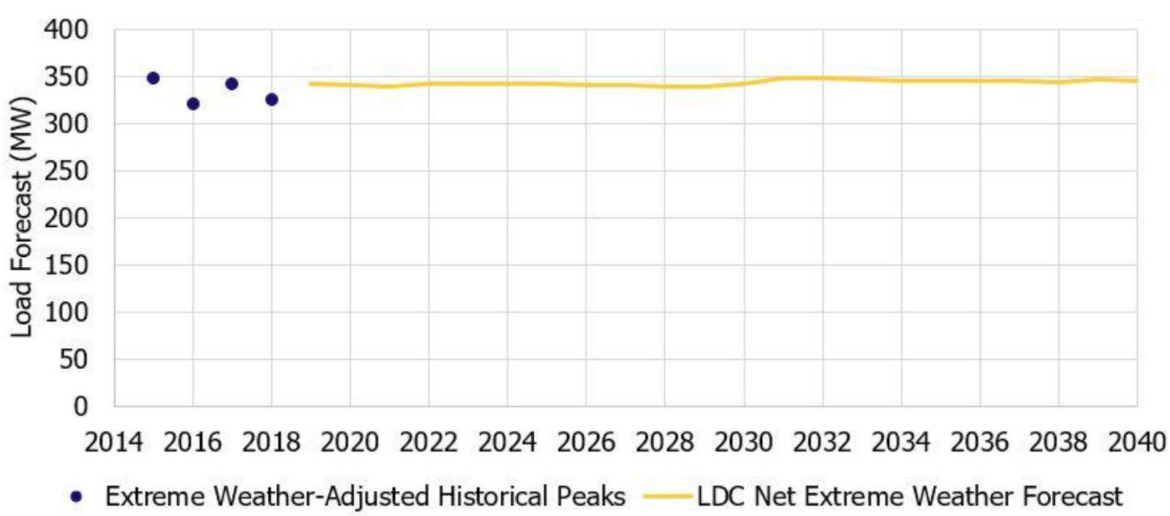


Figure 5-1: East Lake Superior Region Load Forecast

5.2 Study Assumptions

The following other assumptions are made in this report.

- The study period for the RIP assessments is 2019-2038.
- All facilities that are identified in Section 4 and that are planned to be placed in-service within the study period are assumed to be in-service.

- Winter is the critical period with respect to line and transformer loadings. The assessment is therefore based on winter peak loads.
- Station capacity adequacy is assessed by comparing the non-coincident peak load with the station's normal planning supply capacity, assuming a 90% lagging power factor for stations having no low-voltage capacitor banks. Normal planning supply capacity for transformer stations is determined by the winter 10-day Limited Time Rating (LTR).
- Autotransformers and line capacity adequacy is assessed by using coincident peak loads in the area or supplied station(s). Where a circuit is feeding radial load, the capacity adequacy is assessed by using the connected station's non-coincident peak.
- Adequacy assessment is conducted as per Ontario Resource Transmission Assessment Criteria (ORTAC).
- The East-West Tie Transmission Reinforcement is included in the assessment.
- Hydro-electric generation assumption is taken as the output that is coincident with the region's overall 98% dependable output. Wind generation assumption were modelled by IESO based on their summer and winter capacity contribution factors per IESO Reliability Outlook, multiplied by their peak capacity.
- Sault No.3 circuit will be refurbished and return to network configuration at 115kV.

6 ADEQUACY OF EXISTING FACILITIES

THIS SECTION REVIEWS THE ADEQUACY OF THE EXISTING TRANSMISSION LINE AND TRANSFORMER STATION FACILITIES SUPPLYING THE EAST LAKE SUPERIOR REGION OVER THE PLANNING PERIOD (2019-2038). ALL PROJECTS CURRENTLY UNDERWAY ARE ASSUMED IN-SERVICE.

Within the current regional planning cycle two regional assessments have been conducted for the East Lake Superior Region. The findings of these studies are input to this Regional Infrastructure Plan. The studies are:

- 2019 East Lake Superior Region Needs Assessment ("NA") Report
- 2019 East Lake Superior Region Scoping Assessment ("SA") Report
- 2021 East Lake Superior Integrated Regional Resource Plan ("IRRP") and Appendices

This section provides a review of the adequacy of the transmission lines and stations in the East Lake Superior Region. The adequacy is assessed from a loading perspective using the latest regional load forecast provided in Appendix D. Sustainment aspects were identified in the NA report and are addressed in Section 7 of this report. The review assumes that the following projects shown in Table 6-1 will be in-service. Sections 6.1 to 6.4 present the results of this review.

Table 6-1: New Facilities Assumed In-Service

Facility	In-Service Date
'hot' spare transformer at Echo River TS	2023
115kV Sault No.3 circuit re-conductoring	2024

6.1 230 kV Transmission Facilities

The East Lake Superior 230 kV transmission facilities consist of the following 230 kV transmission circuits (please refer to Figure 3-1 and 3-2):

a) Mississagi TS to Third Line TS 230 kV circuits: P21G and P22G
b) Mississagi TS to Wawa TS 230 kV circuit: P25W and P26W
c) Wawa TS to Mackay TS 230 kV circuits: W23K
d) Mackay TS to Third Line 230 kV circuits: K24G

230kV circuits supplying the region are within their thermal limits as per ORTAC over the study period for the loss of a single 230kV circuit in the region. Voltage concerns is observed when applying multiple contingencies on Bulk Electric System (BES) elements as per performance requirements set out in NERC TLP-001-4.

6.1.1 Voltage Concerns on following the loss of P21G and P22G

P21G and P22G are critical 230kV supply circuits that connects Third Line TS with Mississagi TS. A double circuit loss of P21G and P22G due to them being adjacent circuits on common towers, or the loss of either one circuit, followed by a contingency on the companion circuit would cause voltage decline in violation with ORTAC voltage change limits (i.e., in excess of 10%) at Third Line TS and other 115kV facilities supplied from Third Line TS throughout the planning horizon. Loss of both P21G and P22G will also result in the loss of Third Line autotransformer T1 by configuration. IESO's IRRP has determined that the voltage instability threshold for the region is reached when the GLP inflow interface exceed 230MW and both P21G and P22G are out of service.

Third line TS is equipped with Instantaneous Load Rejection Scheme with six load blocks to be armed for the loss of P21G and P22G, or the loss of T1 and T2. Currently, the IESO will direct HOSSM to arm this scheme via Hydro One's Ontario Grid Control Centre (OGCC) using manual phone call, where IESO will request arming of certain amount of load for rejection depending on prevailing system conditions. HOSSM will prioritize selection of available load blocks. IESO has expressed the need to enable remote arming of this scheme directly from IESO control room to make the arming procedure more efficient. Section 7 will discuss in more detail.

6.2 230/115 kV Autotransformers Facilities

The 230/115 kV autotransformers facilities in the region consist of the following elements:

a. Third Line TS 230/115 kV, 150/200/250MVA autotransformers: T1, T2
b. Mackay TS 230/115 kV, 150/200/250MVA autotransformers: T2

Loading of Third Line TS autotransformers has been identified to approach their 10-day LTR when the companion autotransformer is lost. Loading on companion autotransformer during single event contingency (N-1) would be reduced modestly beyond 2024 when the Sault No.3 circuit returns to a network at 115kV (non-radial configuration).

This is not a firm need as there is no existing violations but this is flagged because loading on Third Line autotransformers is approaching its LTR limit and should continue to be monitored. Despite the fact that one of the autotransformer (T2) has been identified for end-of-life replacement by 2025, such replacement would only marginally improve supply capacity by 10MVA for Third Line's autotransformers due to LTR rating of the existing autotransformer (T1), which was put into service since 2007 and is not near End-of-Life.

6.3 115 kV Transmission Facilities

115kV circuits supplying the region are within their thermal limits as per ORTAC over the study period for the loss of a single transmission element in the region. A list of circuits can be found in Appendix B. Capacity overload is observed on 115kV circuit Algoma No.1 and Sault No.3 following multiple contingencies as per performance requirements set out in NERC TLP-001-4.

6.3.1 Capacity overload on 115kV circuit Algoma No.1

A failure of breaker 214 to operate at Patrick St TS will remove Algoma No.2 and Algoma No. 3 circuits from Third Line TS to Patrick St TS by configuration. This results in thermal overload of the remaining Algoma No. 1 circuit beyond its short-term emergency (STE) rating during peak loads at Patrick St TS, of which Algoma No. 1 is the lowest rated circuit out of the three. This thermal overload on Algoma No. 1 can also occur with one of the Algoma circuits initially out of service, followed by the loss of another Algoma circuit.

This is an existing issue which was also identified in the NA and SA report. This is currently mitigated by the Patrick St TS manual load shedding scheme under which load is curtailed manually at Patrick St TS following the loss of one of the Algoma line circuits. This is done to prevent overloading of the Algoma No. 1 circuit in case the second circuit is also lost. Since this scheme is manual, load has to be shed before the actual contingency of the second circuit has taken place. This scheme was designed as an interim solution until a more permanent solution was implemented. The IRRP has recommended a need for a more permanent solution.

6.3.2 Capacity overload of 115kV circuit Sault No.3

During an outage to either P25W or P26W circuit between Wawa TS to Mississagi TS, a contingency on the K24G circuit between Third Line TS and Mackay TS results in the thermal overload of the Sault No.3 circuit beyond its STE ratings starting in 2023 when No.3 Sault circuit is connected in a network configuration[4]. This phenomenon is a result of high East West Transfer (EWT) flows and losing two circuits that carry that flow. [5]

In addition, when one of the Third Line TS autotransformers is out of service, a Sault No.3 circuit operated as network configuration (after its proposed upgrades) helps to alleviate overloading of the companion Third Line TS autotransformer. However, if the second autotransformer is also lost, Sault No.3 circuit will be overloaded beyond its STE rating and causes a significant voltage decline in the 115kV area served by Third Line TS. The risk of capacity overload on Sault No.3 circuit and area voltage decline as a result of losing both autotransformer is presently mitigated by Third line's Instantaneous Load Rejection scheme. Subjected to the outcome of IESO's 2021 Bulk Planning Study with regards to Sault No.3 overloading, the overloading may continue to be a need.

6.4 Step-Down Transformer Station Facilities

There are a total of 11 step-down transformers stations in the East Lake Superior Region, connected to the 230 kV and 115 kV transmission network as listed below. The stations winter peak load forecast is given in Appendix D.

Table 6-2: East Lake Superior Step-Down Transformer Stations

230 kV Connected	115 kV Connected	
Echo River TS	Andrew TS	Chapleau MTS

[4] Sault No.3 circuit is currently operated radial to Mackay GS (G3) and is being refurbished as part of a sustainment project

[5] EWT is defined as the MW flow at Wawa TS on circuits W21M and W22M. By 2023, EWT tie flow will also include the flow of the new NextBridge circuits.

	Anjigami TS	Goulais TS
	Batchawana TS	Hollingsworth TS
	Clergue TS	Northern Ave TS
	Chapleau DS	St Mary CTS
	Tarentorus CTS	

Capacity of Anjigami T1 / Hollingsworth T1 & T2 are exceeded by end of 2024 based on the load forecast provided by LDC, where Hollingsworth T1 & T2 will be overload when Anjigami T1 is out of service, and vice versa. The overload is caused by loading increases on the 44kV circuit that Anjigami TS and Hollingsworth TS supply in parallel. HOSSM is working with the impacted LDC and have proposed to build a new 115/44kV station, with a proposed name Limer TS (subject to change) that will tap off Hollingsworth 115kV circuit to handle the load increase.

6.5 Bulk Areas Need

There is a potential for significant growth in industrial load in the ELS region over the planning period which would have a material impact on the bulk transmission system outside the region. Hence, the IESO has initiated a bulk planning study for this scenario outside of the regional planning process.

Based on the reference load forecast included in the IRRP, the following bulk system need was identified and will be further coordinated with the bulk planning study described above:

- Following the loss of one of the 230 KV circuits, P25W or P26W circuits from Mississagi TS to Wawa TS, the companion circuit becomes loaded beyond its LTR rating under high westward power flow on the EWT.

Results and recommendations from the bulk planning study would be published separately. HOSSM and HONI will work with IESO to address recommendations as appropriate.

7 REGIONAL NEEDS AND PLANS

THIS SECTION DISCUSSES ELECTRICAL INFRASTRUCTURE NEEDS IN THE EAST LAKE SUPERIOR REGION AND SUMMARIZES THE PLANS DEVELOPED TO ADDRESS THESE NEEDS.

This section outlines and discusses electrical infrastructure needs in the East Lake Superior Region and plans to address these needs. The electrical infrastructure needs encompass both end of life replacement needs identified in the Need Assessment phase, and needs identified in section 6. A list of needs are summarized below in Table 7.1.

Table 7-1: Identified Near and Mid-Term Needs in East Lake Superior Region

Section	Facilities/Circuit	Need	Timing
7.1	Third Line TS/OGCC	Enable remote arming of Third Line TS Instantaneous Load Rejection Scheme	Immediate
7.2	Third Line TS	End of life Protection replacement	2022
7.3	Patrick St TS, Algoma No.1 overload	Automate existing manual load curtailment scheme to meet NERC standards	Immediate
7.4	Echo River TS	Transmission Supply Reliability / End of Life 230kV Breaker replacement	2023/2024
7.5	115kV Sault No.3	Sault No.3 Structure and End of Life Conductor Replacement[6]	2024
7.6	Batchawana TS and Goulais TS	End of Life component replacement	2024
7.7	Patrick St TS	End of Life 115kV breaker replacement	2024
7.8	Third Line TS	T2 End of Life Replacement	2025
7.9	Northern Ave TS	T1 End of Life replacement	2025

[6] To coordinated with IESO's 2021 Bulk Planning Study Regarding Sault No.3 Circuit Overloading

7.10	Anjigami/Hollingsworth TS	Anjigami/Hollingsworth Transformers Overload	2024
7.11	Clergue TS	End of life metal clad switch gear replacement	2026
7.12	Hollingsworth TS	End of life Protection replacement	2026
7.13	Watson TS	End of life metal clad switch gear replacement	2026

7.1 Third Line TS – Enable remote arming of Third Line TS Instantaneous Load Rejection Scheme.

7.1.1 Description

Instantaneous Load Rejection Scheme at Third line TS are designed to respond to the loss of both P21G and P22G, or the loss of both T1 and T2. This scheme is currently armed under the direction of IESO. Upon IESO request, OGCC will manually arm the scheme and prioritized available load blocks for rejection. OGCC has established communication channels to perform arming function via Hydro One Network Management System (NMS).

7.1.2 Alternatives and Recommendation

The following alternatives were considered to address Main TS end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo**: This alternative was considered and rejected as it will not address the manual process involved in arming of the load rejection scheme, as well as the selection of load blocks to be armed. The risk of communication delays between IESO and OGCC is not mitigated.

2. **Alternative 2 – Enable remote arming of Third Line TS Instantaneous Load rejection scheme:** Under this alternative, Hydro One will work with IESO to make necessary control points available on IESO's Energy Management System (EMS) interface such that IESO's control command can be relayed to OGCC's NMS via existing Inter-Control Centre Communication Protocol (ICCP) link, which will subsequently be relayed to Third Line's Instantaneous Load Rejection Scheme.

The Study Team recommends Alternative 2 as the technically preferred and most cost-effective alternative because this will facilitate the automation of dispatch arming from IESO in a real-time setting, and eliminate manual communications delays between IESO and Hydro One. Further, given the ICCP infrastructure already exists, the cost to perform alternative 2 is expect to be limited to control points and status points set up in NMS and EMS respectively, as well as testing activities that can be done in both ends to ensure functionality. The estimated cost for this upgrade is about $10,000 and is expected to in-service by end of 2021.

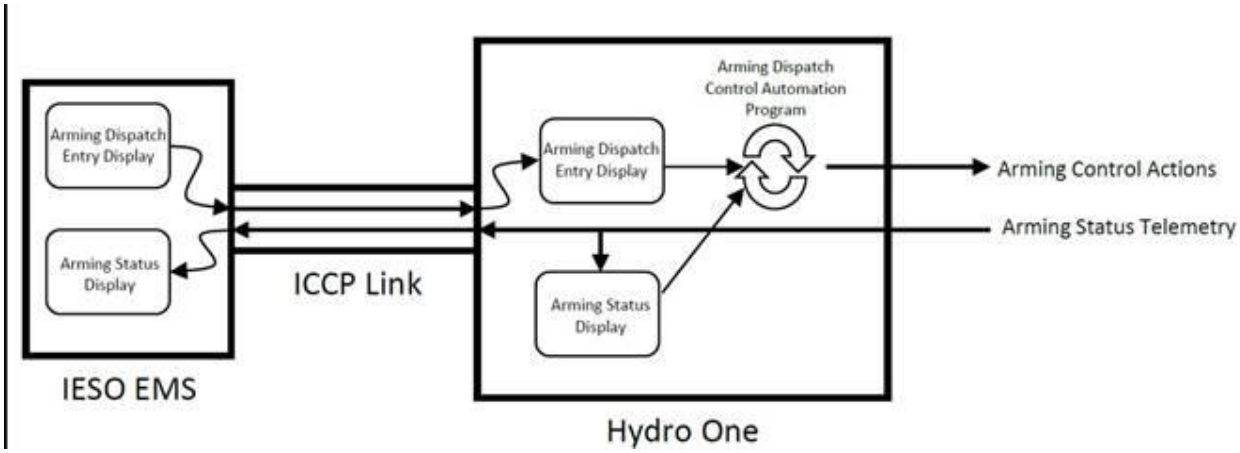


Figure 7-1: ICCP link between IESO and Hydro One.

7.2 Third Line TS – End of life Protection Replacement

7.2.1 Description

Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Third line TS 115kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, No.3 Sault circuit and Northern Ave circuit. It also supplies two (2) LDC HV load supply stations via 115kV circuits GL1SM GL2SM, GL1TA, and GL2TA. Based on an asset condition assessment, P21G's and P22G's line protections are approaching end of life. Further, due to legacy reasons, P21G's and P22G's line protection do not meet standard physical separation requirement .

7.2.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to end-of-life asset condition and would result in increased maintenance expenses and reduce supply reliability to the ELS region.

2. **Alternative 2 – Replace end-of-life protection as per current standard:** Under this alternative the existing end-of-life protection will be replaced with new protection relay consistent with Hydro One standard. This alternative will also implement 'A' and 'B' protection separation, which will

bring these protection be in compliance with reliability standards, addresses the end-of-life assets need, minimizes losses and maintains reliable supply to the customers in the area.

The Study Team recommends Alternative 2 – replace end-of-life protection relay. The protection replacement work is expected to be complete by 2022.

7.3 Patrick St TS – Automatic Load Rejection Scheme

7.3.1 Description

Patrick St TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2 and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No .1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area. Based on IESO IRRP findings, upon a breaker failure of breaker 214, or a contingency on either Algoma No.2 or Algoma No.3 circuit, followed by another contingency on the remaining circuit, Algoma No.1 will be overloaded beyond its STE rating during peak load. At present, a manual load shedding scheme is implemented as an interim solution until a more permanent solution is available.

7.3.2 Alternatives and Recommendation

The following alternatives were considered to address the interim manual load shedding scheme need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of circuit overload during contingency and could result in equipment (overhead conductor) damage, increase public safety risk and reduce supply reliability to connected customers.

2. **Alternative 2 – Implement Automatic Load Rejection Scheme at Patrick St TS:** This alternative would implement an automatic load rejection upon the loss of Algoma No.2 and Algoma No.3 to reject load blocks and respect the existing LTE rating of Algoma No.1 circuit.

Considering above options, the Study Team recommends that Hydro One proceed with Alternative 2, consistent with recommendation from the ELS's IRRP.

7.4 Echo River TS – Install Spare 230kV Transformer (2023) and end of life 230kV breaker replacement (2024)

7.4.1 Description

Echo River TS is a 230kV load supply station. The station consists of a single 230/115/34.5kV autotransformer and a single 230kV circuit breaker (556) to supply two (2) 34.5 kV customer feeders. Historically, load at Echo River TS can be transferred to Northern Ave TS 34.5 kV feeders via the API's distribution system in case of outages at Echo River TS, such as transformer maintenance or failure.

As per the 2nd cycle of Need Assessment completed in Q2 2019 for the ELS region, it has been identified that the existing back up from Northern Ave TS can no longer provide adequate voltage support at peak load during a transformer outage at Echo River TS.

Echo River 230kV breaker 556 is a live tank minimum oil breaker, which has also been identified to be end of life and obsoleted based on asset condition assessment.

7.4.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address system reliability needs and HOSSM asset needs due to asset condition. This alternative would result in increased maintenance expenses and reduce supply reliability to the customers.

2. **Alternative 2 – "Cold" spare 230kV Transformer and replace end of life 230kV breaker :** install a "cold" spare in Echo River TS that is completed with new spill containment only, without 230kV and 34.5kV connection facilities and dedicated protection equipment. The spare will not normally put on potential. This alternative is not recommended as the load restoration time associated with connecting the unit and making it ready to serve load would exceed ORTAC load restoration requirement.

3. **Alternative 3 – "Hot" spare 230kV Transformer and replace end of life 230kV breaker:** install a "hot" spare in Echo River TS that is completed with new 230kV and 34.5kV connection facilities, dedicated protection equipment and new spill containment systems. The spare transformer is usually on potential and ready to serve load upon switching. This alternative can significantly shorten load restoration time to respect ORTAC load restoration timeline in the event of a transformer outage due to maintenance or failure, which improves local transmission supply reliability.

The Study Team recommends Alternative 3 – "Hot" spare 230kV Transformer and replace end of life 230kV breaker. The spare transformer is planned to be completed by 2023, while the breaker replacement work is planned to be completed in 2024. In lieu of replacing the breaker HOSSM will install a 230 kV circuit switcher and enable transfer trip functionality between Echo River TS and it's terminal stations.

7.5 115kV Sault No.3 Structure and Conductor Replacement

7.5.1 Description

Built in 1929, Sault No.3 is a 90 km long 115kV transmission circuit that runs from MacKay TS 115kV station yard to Third Line TS 115kV station yard. This circuit provides an alternative path for local generation to reach load centres close to the Sault Ste. Marie area. Based on asset condition assessment, approximately 70km of the circuit's conductor from Goulais TS (str # 129) to MacKay TS is the original conductor, and has been rated between "Poor" and "Very Poor" as it has multiple component (sleeves) failures. This circuit also accounts for 39% of all line equipment related outages experienced over the 2013 – 2017 period within HOSSM's sytem. The circuit is currently de-rated as a pre-cautionary action to minimize further stress. Due to the de-rating, Sault No.3 circuit is also forced to operate in a radial configuration to Mackay G3 to limit loading on the line. The end of life replacement work would include 'like for standard' conductor replacement and replacement of selected wood poles along the corridor as condition warrants.

HOSSM has completed the detail project defitnition work for this project. It is noted that the on-going IESO bulk system studies have considered upgrading Sault 3 to 230kV[7] as a potential solution. IESO bulk system studies is expected to be available Q4 2021. Provided that IESO's recommendation is to refurbish the line as per current plan, the project is expected to be completed by 2024.

7.5.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition. Failure of this circuit can impact the power supply to load centres close to the city of Sault Ste. Marie.

2. **Alternative 2 - Replace conductor, structures and associated End-of-Life components with Hydr One standard 115kV equipment:** Under this alternative, the existing conductor and wood pole that are assessed to be end of life will be replaced with new 115 kV rated line and structures. This alternative will also allow Sault No.3 to return to its network configuration.

The Study Team recommends Alternative 2 – the replacement of the end-of-life conductor and wood pole structures between Mackay TS and Goulais TS (str # 129) as it addresses the end-of-life assets need and maintains reliable supply to the customers in the area.

7.6 Batchawana TS and Goulais – End of life Component Replacement

7.6.1 Description

Batchawana TS and Goulais Bay TS are load supply stations with single transformer to supply to the Batchawana Bay and Goulais Bay areas. Goulais Bay TS is about 30 km North of Sault Ste. Marie, while Batchawana TS is about 47 km North of Sault Ste. Marie along Hwy 17. Both are connected to 115kV No.3 Sault circuit. Figure 7-2 below shows geographical location of both station. Based on asset condition assessment, both stations are at End-of-life stage with obsoleted equipment including power transformers, protections (fuse), batteries, chargers, steel structure foundations and remote terminal units. Both stations are also built with legacy design standards and do not provide adequate clearance to today's standard. Their single transformer configuration has also made it difficult to schedule and perform maintenance.

[7] Possibly upgrading to 230kV standard and operate at 115kV until 230kV operation is needed for the bulk system.

Figure 7-2: Batchawana TS and Goulais Bay TS on 115kV circuit

7.6.2 Alternatives and Recommendation

A detailed assessment that analyzed supply options for Batchawana TS and Goulais Bay TS was carried out between HOSSM and API from 2019 -2020 to compare and evaluate supply options based on Transmission and Distribution supply reliability and performances. The assessment compared three (3) different options, they are:

- Option 1: Refurbish both Goulais Bay TS and Batchawana TS using a new 115kV, 3 –phase power transformer, with provision for a 115kV Mobile Unit substation (MUS) connection facility in each station. Transformer capacity to be sized to handle the long term peak forecast of the individual stations.

- Option 2: Consolidate Goulais Bay TS and Batchawana TS into a 'New' TS that is equipped with two 20MVA, 3-phase transformer to supply both distribution sub-system at either 12.5kV or 25kV. The location of this 'New' TS would be in the vicinity of Goulais bay.

- Option 3: Consolidate Goulais Bay TS and Batchawana TS into a 'New' TS with dedicated 25kV "express feeder" between Goulais and Batchawana. This 'New' TS would be located in the vicinity of Goulais bay, and be equipped with two 20MVA, 3-phase transformer to supply both distribution sub-system at either 12.5kV or 25kV. An additional 25/12.5kV unit is required on the distribution system in the vicinity of Batchawana bay to convert voltage from the incoming 25kV dedicated "express feeder" to 12.5kV in order to supply distribution sub-system in the vicinity of Batchawana bay.

Depending on the choice of distribution voltage, there are two (2) different scenarios (12.5kV vs 25kV) for each option above. Evaluation of alternatives was completed by HOSSM and API as documented in the 2021 East Lake Superior Regional Local Planning Report. As per the report's recommendation, HOSSM is proceeding with option 1 - Refurbish both Goulais Bay TS and Batchawana TS. More details related to the supply option analysis can be found in the Local Planning Report – Supply Option Analysis for Goulais and Batchawana (2020), available on Hydro One public website. Refurbishment for both stations are expected to be completed in 2024.

7.7 Patrick St TS – End of life 115kV breaker replacement

7.7.1 Description

Patrick St TS is an 115kV switching station that consists of thirteen (13) 115kV breakers. It connects to Third Line TS – 115kV station yard via 115kV Algoma No. 1, No. 2 and No. 3 circuits. It also connects to Clergue TS via 115kV Clergue No .1 and No. 2 circuits. The station supplies major industrial customers in the Sault Ste. Marie area. Based on asset condition assessment, breaker 208, 211, 214 and 217 are minimum oil live tank breakers that are considered End of Life and obsolete.

7.7.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability for customers.

2. **Alternative 2 - Replace the end-of-life breakers with new standard breakers:** This alternative involves the replacement of breaker 208, 211, 214 and 217 with new SF6 breakers in similar ratings.. This alternative is recommended as it addresses the end-of-life asset needs and maintains reliable supply to customers connected at Patrick St TS by reducing the risk of breaker failure; and reducing on-going maintenance cost associated with obsolete breaker technology.

Alternative 2 is recommended. The project is expected to be completed by 2024.

7.8 Third Line TS – T2 End of Life Replacement

7.8.1 Description

Third Line TS is a major transformer station in the region and it consists of two (2) 230/115kV, 150/200/250MVA autotransformers supplied by 230kV circuits K24G, P21G and P22G. Third line TS 115kV station yard supplies multiple load stations via Algoma No. 1, No. 2, No. 3 circuits, No.3 Sault circuit and Northern Ave circuit. It also supplies two (2) PUC HV load supply stations via 115kV circuits GL1SM GL2SM, GL1TA, and GL2TA. Among the 2 autotransformers, T2 is at end of life based on asset condition assessment. Based on long term load forecast, units with similar ratings are required for the end of life autotransformer T2 replacement.

7.8.2 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to the region.

2. **Alternative 2 – Replace T2 with equivalent size unit as per current standard:** This alternative would replace old T2 with a unit that has equivalent rating. This is recommended alternative as it will mitigate risk of autotransformer failure due to its deteriorating conditions and maintain supply reliability of the region.

3. **Alternative 3 – Replace T2 with larger size unit:** This alternative would replace old T2 with a unit that has higher rating. This alternative is rejected as a 230/115kV autotransformer at 150/200/250MVA is currently the highest rating available based on HOSSM and Hydro One standards.

Alternative 2 is recommended. The project is expected to be completed by 2025.

7.9 Northern Ave TS – T1 End of Life Replacement

Northern Ave TS is a 115kV load supply station that is connected to Third Line TS via 115kV Northern Ave circuit. Northern Ave Transformer T1 is a 115/34.5kV, 20/26.7MVA step down transformer that supplies Algoma Power Inc. via one (1) 34.5kV feeder. Transformer T1 is at end of life. Historically, Northern Ave TS has been used as a backup supply to Echo River TS to facilitate outages. Reliance on Northern Ave TS is expected to reduce starting 2023 as the spare unit at Echo River TS comes into service in 2023. The longer term forecast for Northern Ave TS peaks at 2.7MW.

7.9.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace T1 with a smaller MVA size unit as per current standard:** This alternative would replace T1 with a 'like for similar' unit that has a smaller MVA rating compared to existing T1, and would be adequate for Northern Ave's long term load forecast. This is recommended alternative as it will mitigate risk of transformer failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2025.

7.10 Anjigami/Hollingsworth TS – Transformer overload.

Anjigami TS is a 115kV/44kV load supply station with a single transformer. Hollingsworth TS is a 115kV/12.5kV/44kV station that supplies load on 44kV, and connected to Hollingsworth CGS on the 12.5kV. Anjigami's and Hollingsworth's 44kV feeders are connected to each other with a 10km long 44kV line to supply LDC load on No.4 circuit. Base on LDC load forecast, load increase on 44kV system by end of 2024 would exceed transformer capacity in both Anjigami TS and Hollingsworth TS when the companion station is out of service. HOSSM is working with API and have proposed to build a new 115/44kV station, with a proposed name Limer TS (subject to change) that will tap off Hollingsworth 115kV circuit to handle the load increase.

7.10.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the transformer capacity needs based on load forecast.

2. **Alternative 2 – Replace Anjigami T1, Hollingsworth T1 and T2 with a larger MVA size units as per current standard to handle load increases:** This alternative is considered but not recommended as both Anjigami TS and Hollingsworth TS have a limited footprint, and site expansion would be required for both sites for such upgrade. Further, due to Hollingsworth TS existing configuration, upgrades are also required on all existing 12.5kV facilities, including disconnect switches, breakers, and overhead bus work to accommodate the load increase.

3. **Alternative 3 – Build new 115/44kV 'Limer TS' that will be supplied from Hollingsworth 115kV circuit, transfer existing LDC load from existing 44kV system to 'Limer TS' :** This alternative would build a new 115/44kV station in the vicinity of Hollingsworth TS and tap off from 115kV Hollingsworth circuit to supply new loads as well as existing load that are presently supplied by Anjigami/Hollingsworth 44kV system. The new station would be similar to a DESN station with two (2) 115/44kV, 50/67/83MVA transformers as per current HONI standard, HV

and LV connection facilities such as circuit switchers and feeder breakers, modern protections and telecommunication systems to service the new load. API will re-route their 44kV feeder(s) and connect to 'Limer TS'.

Given the alternatives above, Alternative 3 is recommended because it is expected to be the most cost efficient alternatives. Compared to Alternative 2, where it will require the coordination of 2 environmental approvals at different sites for site expansion, replacement of three (3) transformer (Anjigami T1, Hollingsworth T1 and T2), and upgrade on existing 12.5kV equipment at Hollingsworth TS, Alternative 3 has a more concise scope. Building new station will also have less outage constraints when compared to upgrading existing facilities. HOSSM will continue to work with API to develop a local solution. The project is expected to be completed by end of 2024/early 2025.

7.11 Clergue TS - End of life metal clad switch gear replacement

Clergue TS is a 115kV station that connects Clergue Generating Station and LSP co-generation station to the HOSSM system via two (2) 115kV circuits emanating from Patrick St TS. Based on an asset condition assessment, the existing 12 kV minimum-oil metal-clad switchgear is at End-of-Life and obsoleted

Based on the load forecast and expected system conditions, similar equipment ratings are required for end of life replacement.

7.11.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace existing metal clad switch gear with SF6 metal clad switch gear as per current standard:** This alternative would replace existing minimal oil metal clad switch gear with SF6 metal clad switch gear. This is recommended alternative as it will mitigate risk of switch gear failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2026.

7.12 Hollingsworth TS – End of life Protection Replacement

Hollingsworth TS is a 115kV station that connects Hollingsworth Generating Station and is supplied by Hollingsworth 115kV circuit. Majority of protection relay equipment in Hollingsworth TS were in-serviced 2005. Based on asset condition assessment, the existing protection relay would approach end of life by 2025.

7.12.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace end of life protection with "like for like" protection relay as per current standard:** This alternative would replace identified end of life protection relays with as per current standard. This is recommended alternative as it will mitigate risk of protection relay failure due to their deteriorating conditions and maintain supply reliability to connected customers.

Alternative 2 is recommended. The project is expected to be completed by 2025

7.13 Watson TS - End of life Metal Clad switch gear replacement

DA Watson TS is a 115kV load supply station that also has connectivity with three (3) local hydro generating stations. The station has two 45/60/75 MVA transformers and nine 34.5kV feeders using metal clad switch gear. Based on an asset condition assessment, the existing minimal oil metalclad switch gear are at End of life and obsolete

7.13.1 Alternatives and Recommendation

The following alternatives were considered to address the end-of-life assets need:

1. **Alternative 1 - Maintain Status Quo:** This alternative is rejected as it does not address the risk of failure due to asset condition and would result in increased maintenance expenses and reduce supply reliability to connected customers.

2. **Alternative 2 – Replace existing metal clad switch gear with SF6 metal clad switch gear as per current standard:** This alternative would replace existing minimal oil metal clad switch gear with SF6 metal clad switch gear. This is recommended alternative as it will mitigate risk of equipment failure due to its deteriorating conditions and maintain supply reliability of the station.

Alternative 2 is recommended. The project is expected to be completed by 2026.

8 CONCLUSIONS AND NEXT STEPS

THIS REGIONAL INFRASTRUCTURE PLAN CONCLUDES THE REGIONAL PLANNING PROCESS FOR THE EAST LAKE SUPERIOR REGION.

The major infrastructure investments recommended by the Study Team in the near and mid-term planning horizon are provided in Table 8-1 below, along with their planned in-service date and budgetary estimates for planning purpose.

Table 8-1: Recommended Plans in East Lake Superior Region over the Next 10 Years

No.	Need	Recommended Action Plan	Planned I/S Date	Budgetary Estimate
1	Eliminate/Minimize manual communication between IESO and OGCC when arming Third Line Instantaneous Load Rejection Scheme	Enable remote arming of Third Line Instantaneous Load Rejection Scheme via ICCP line between IESO's EMS and HONI's NMS	2021	$10K
2	Third line TS: End of life Protection	Replace end of life protection per current standard	2022	$0.8M
3	Echo River TS : Transmission Supply Reliability and end of life breaker	Install 'hot' spare transformer and replace end of life breaker	2023/2024	$11.5M
4	115kV Sault No.3: end of life structures and conductor	Replace end of life structure and conductor per current standard[8]	2024	$54.4M
5	Batchawana TS: End of life components	Refurbish Batchawana TS with MUS provision	2024	$6.2M
6	Goulais TS: End of life components	Refurbish Goulais TS with MUS provision	2024	$13.4M
7	Patrick St. TS, Algoma No.1 overload	Implement Automatic Load Rejection Scheme at Patrick St. TS	2023	$1.2M
8	Patrick St. TS: End of life 115kV breaker	Replace end of life 115kV breakers	2024	$3.3M
9	Third Line TS : T2 end of life	Replace end of life T2	2025	$16.4M
10	Northern Ave TS: end of life component replacement	Replace end of life T1 with smaller MVA unit and protection relays per current standard	2025	$2.5M
11	Anjigami/Hollingsworth TS : Transformer overload	Build new 115/44kV Station - HOSSM to work with API to continue to develop solutions	2024/2025	$30M

[8] To coordinated with IESO's 2021 Bulk Planning Study Regarding Sault No.3 Circuit Overloading

12	Clergue TS: End of life metal clad switch gear	Replace end of life switch	2026	$5.2M
13	Hollingsworth TS: End of life Protection relay	Replace end of life protections	2025	$1.1M
14	D.A. Watson TS: End of life metal clad switch gear	Replace end of life switch gear	2026	$9.2M

The Study Team recommends that:

- Hydro One to continue with the implementation of infrastructure investments listed in Table 8-1 while keeping the Study Team apprised of project status;
- Any other identified needs/options in the long-term will be further reviewed by the Study Team in the next regional planning cycle.

9 REFERENCES

[1] East Lake Superior Region Needs Assessment (2019)

[2] East Lake Superior Region Scoping Assessment (2019)

[3] Local Planning Report – Supply Option Analysis for Goulais and Batchawana (2020)

[4] East Lake Superior Integrated Regional Resource Plan (2021)

[5] East Lake Superior Integrated Regional Resource Plan - Appendices (2021)

APPENDIX A. STATIONS IN THE EAST LAKE SUPERIOR REGION

Station	Voltage (kV)	Supply Circuits
Andrews TS	115/25	Andrew 115kV
Anjigami TS	115/44	High falls No.1 /Highfalls No.2
Batchawana TS	115/12.5	Sault No.3
Chapleau DS	115/25	W2C
Chapleau MTS	115kV	W2C
Clergue TS	115/12.5	Clergue No.1 / Clergue No.2
D.A. Watson TS	115/34.5	Magpie 115kV/High falls No.1 /Highfalls No.2
Echo River TS	230/34.5	P22G
Flakeboard CTS	115	Leigh's Bay 115kV
Gartshore SS	115	Gartshore No.1 / Gartshore No.2/ Gartshore No.3 / Hogg 115kV / Andrews 115kV
Gold Mine CTS (Magnacon Mine)	115	Steephill 115kV
Goulais Bay TS	115/12.5	Sault No.3
Heyden CSS	230	K24G
Hollingsworth TS	115/12.5/44	Hollingsworth 115kV
Hwy 101 SS	44	Anjigami 44kV/Limer 44kV
Mackay TS	230	K24G/W23K
Mackay TS	115	Gartshore No.1 / Gartshore No.2/ Mackay No.1/Mackay No.2/Sault No.3
Magpie SS	115	Harris 115kV/Steephill 115kV /Mission Falls 115kV/Magpie 115kV
Mile Hill CTS	230	K24G
Northern Ave. TS	115/34.5/12.5	Northern Ave 115kV
Patrick St. TS	115/34.5	Algoma No.1/No.2/No.3 , Clergue No.1 /No.2
St Mary CTS	115/34.5	GL1SM / GL2SM
Tarentorus CTS	115/34.5	GL1TA / GL2TA
Third Line TS	230	K24G/P21G/P22G
Third Line TS	115	Sault No.3, Algoma No.1/No.2/No.3, Northern Ave 115kV
Wallace Terrace CTS	115/34.5	Leigh's Bay 115kV

Wawa TS	230	P25W/P26W/W21M/W22M/W35M*/W36M*
Wawa TS	115	W2C/ Hollingsworth 115kV

*after the completion of East West Tie

APPENDIX B. TRANSMISSION LINES IN THE EAST LAKE SUPERIOR REGION

Location	Circuit Designations	Voltage (kV)
Mississagi x Third line	P21G , P22G	230
Mississagi x Wawa	P25W, P26W	230
Third line x Mackay	K24G	230
Mackay x Wawa	W23K	230
Third line x Mackay	Sault No.3	115
Third line x Patrick St.	Algoma No.1 / No.2 / No.3	115
Third line x Norther Ave	Northern Ave 115kV	115
Third line x St Mary CTS	GL1SM, GL2SM	115
Third line x Tarentorus CTS	GL1TA , GL1TA	115
Patrick st x Flakeboard CTS	Leigh's Bay 115kV	115
Patrick St. x Clergue TS	Clergue No.1 / No.2	115
Mackay GS x Mackay TS	Mackay No.1 / No.2	115
Gartshore SS x Mackay TS	Gartshore No.1 / No.2	115
Gartshore SS x Hogg CGS	Hogg 115kV	115
Gartshore SS x Andrew CGS	Andrew 115kV	115
Magpie SS x Mission Falls CGS	Mission falls 115kV	115
Magpie SS x Steephill CGS	Steephill 115kV	115
Magpie SS x Harris CGS	Harris 115kV	115
Magpie SS x DA Watson TS	Magpie 115kV	115
DA Watson TS x Wawa TS	High Falls No.1/No.2	115
Hollingsworth TS x Wawa TS	Hollingsworth 115kV	115

Anjigami TS x Hwy 101 SS	Anjigami 44kV	44
Hollingsworth TS x Hwy 101 SS	Limer 44kV	44

APPENDIX C. DISTRIBUTORS IN THE EAST LAKE SUPERIOR REGION

Distributor Name	Station Name	Connection Type
Algoma Power Inc.	Andrew TS	Tx
	Anjigami TS	Tx
	Batchawana TS	Tx
	D.A. Watson TS	Tx
	Echo River TS	Tx
	Goulais TS	Tx
	Mackay TS (115kV)	Tx
	Northern Ave TS	Tx
	Hollingsworth TS	Tx
Distributor Name	**Station Name**	**Connection Type**
Chapleau PUC	Chapleau MTS	Tx
Hydro One Networks Inc. (Dx)	Chapleau DS	Dx
PUC Distribution	St Mary CTS	Tx
	Tarentorus CTS	Tx

APPENDIX D. EAST LAKE SUPERIOR REGION LOAD FORECAST

Table D-1: East Lake Superior Non-coincident peak Load Forecast, with the Impacts of Energy-Efficiency Savings per station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	1.56	1.85	1.86	1.88	1.90	1.91	1.93	1.95	1.97	1.98	2.00	2.02	2.04	2.05	2.06	2.08	2.10	2.12	2.14	2.15
DA Watson TS	8.53	8.57	8.55	8.56	8.57	8.58	8.60	8.63	8.67	8.71	8.75	8.80	8.87	8.93	8.99	9.06	9.13	9.20	9.26	9.32
Echo River TS	14.18	14.23	14.19	14.19	14.17	14.18	14.20	14.23	14.28	14.33	14.38	14.45	14.57	14.67	14.80	14.95	15.06	15.17	15.25	15.33
Goulais Bay TS	8.00	8.00	9.49	9.81	10.40	10.70	10.76	10.83	10.90	10.96	11.01	11.07	11.13	11.18	11.23	11.29	11.36	11.43	11.50	11.57
Limer TS	13.18	13.74	13.81	13.88	13.99	54.00	54.00	28.62	28.65	28.68	28.70	28.76	56.00	56.00	56.00	56.00	56.00	56.00	56.00	56.00
Andrews TS	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22	0.22
Mackay TS	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Northern Av TS	2.50	2.51	2.50	2.51	2.51	2.51	2.52	2.53	2.54	2.55	2.57	2.58	2.60	2.62	2.63	2.65	2.67	2.70	2.71	2.73
Chapleau DS	6.31	6.47	6.51	9.24	9.32	9.38	9.44	9.51	9.59	9.68	9.76	9.84	9.94	10.03	10.13	10.23	10.33	10.44	10.53	10.63
Chapleau MTS	4.47	4.36	4.44	4.19	4.69	4.58	4.59	4.59	4.21	4.15	4.14	4.27	4.27	4.27	4.27	4.28	4.29	4.29	4.29	4.30
PUC Distribution Inc.	120.7	119.5	117.5	115.9	114.2	112.7	111.4	110.0	108.9	107.9	106.8	109.7	116.5	115.7	114.9	114.2	113.6	112.9	112.3	111.5

Table D-2: East Lake Superior Forecasted Impacts of Energy-Efficiency Savings due to Codes , Standards and Funded CDM Program

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.03	0.03	0.04	0.04	0.04	0.04	0.04	0.04
DA Watson TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Echo River TS	0.11	0.20	0.20	0.20	0.16	0.16	0.16	0.16	0.16	0.16	0.18	0.20	0.24	0.27	0.30	0.32	0.33	0.34	0.34	0.34
Goulais Bay TS	0.07	0.12	0.12	0.12	0.09	0.09	0.09	0.09	0.09	0.09	0.11	0.12	0.14	0.16	0.18	0.19	0.20	0.20	0.20	0.20
Limer TS	0.11	0.19	0.19	0.19	0.15	0.15	0.15	0.15	0.15	0.15	0.17	0.19	0.23	0.25	0.28	0.30	0.32	0.32	0.32	0.32
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.02	0.04	0.04	0.04	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.04	0.04	0.05	0.05	0.06	0.06	0.06	0.06	0.06
Chapleau DS	0.07	0.12	0.12	0.12	0.10	0.10	0.10	0.10	0.10	0.10	0.12	0.13	0.16	0.18	0.20	0.22	0.23	0.23	0.23	0.23
Chapleau MTS	0.03	0.06	0.06	0.05	0.05	0.05	0.05	0.04	0.04	0.04	0.05	0.06	0.07	0.07	0.08	0.09	0.09	0.09	0.09	0.09
St. Mary's TS	0.91	1.58	1.54	1.54	1.16	1.16	1.13	1.12	1.12	1.08	1.17	1.29	1.46	1.60	1.76	1.87	1.93	1.91	1.88	1.86
Tarentorus TS	1.16	2.02	1.97	1.98	1.49	1.48	1.45	1.43	1.43	1.39	1.50	1.66	1.88	2.05	2.25	2.40	2.47	2.44	2.41	2.38
Total	**2.56**	**4.45**	**4.36**	**4.39**	**3.33**	**3.32**	**3.27**	**3.23**	**3.23**	**3.15**	**3.45**	**3.84**	**4.39**	**4.82**	**5.32**	**5.69**	**5.87**	**5.84**	**5.79**	**5.74**

Table D-3: East Lake Superior IRRP Forecasted DER by station

Transformer Station	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
Batchawana TS	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
DA Watson TS	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Echo River TS	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.20	0.16	0.12	0.08	0.02	0.01	0.00	0.00	0.00
Goulais Bay TS	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.03	0.02	0.01	0.01	0.01	0.00	0.00	0.00	0.00
Limer TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Andrews TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Mackay TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Northern Av TS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau DS	2.65	2.65	2.65	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Chapleau MTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
St. Mary's TS	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	7.85	0.23	0.18	0.16	0.16	0.16	0.14	0.00	0.00
Tarentorus TS	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	3.93	0.14	0.10	0.06	0.03	0.03	0.02	0.00	0.00	0.00

Appendix F

Renewable Energy Generation Plan Submitted to the IESO

Engineering Department
500 Second Line East, P.O. Box 9000
Sault Ste. Marie, Ontario, P6A 6P2
Phone: (705) 759-6576
Email: eng-dept@ssmpuc.com

ECRA/ESA Lic. # 7001626

October 26, 2021

Independent Electrical System Operator
120 Adelaide Street West, Suite 1600,
Toronto, ON, M5H 1T1

Re: Renewable Energy Generation Plan for PUC Distribution Inc.
Request to IESO for comment Letter

Dear Sir/Madame:

PUC Distribution Inc. (PUC) is presently preparing its 2023 Cost of Service Rate Application as well as finalizing its 2023-2027 Distribution System Plan (DSP) for submittal to the Ontario Energy Board (OEB). In accordance with the OEB's Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements we are hereby respectfully requesting the IESO provide a "Letter of Comment" with respect to our Renewable Energy Generation (REG) plans which you will find attached.

PUC would greatly appreciate receiving the IESO's Letter of Comment at the earliest opportunity as PUC will need to incorporate the feedback received into their DSP.

We trust this letter and submittal is adequate and clear for your use in the intended purpose but should there be any associated questions or comments, kindly direct them to the undersigned.

Regards,

M Paradis

Mitchell Paradis, P.Eng
Protection and Control Engineer
705-759-6585
mitchell.paradis@ssmpuc.com

PUC Services Inc.
500 Second Line East, P.O. Box 9000
Sault Ste. Marie, ON, P6B 4K1

Renewable Energy Generation Plan

PUC Distribution Inc.

2021-10-26

Executive Summary

PUC Distribution Inc. (PUC) is a Local Distribution Company (LDC) licensed to distribute electricity in its service territory which includes most of the City of Sault Ste. Marie, Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. PUC serves approximately 33,500 customers, hosts 63MW of Renewable Energy Generation (REG) and 7MW/7MWh of energy storage infrastructure.

PUC has prepared this document summarizing how it takes the connection of REG projects into account in its planning. It also serves to demonstrate how compliance is achieved with associated regulatory requirements as described in the Ontario Energy Board's (OEB) Filing Requirements for Electricity Transmission and Distribution Applications, Chapter 5, Consolidated Distribution System Plan Filing Requirements. In broad summary that document identifies that LDCs must have long term plans that address REG and that, with respect to those plans that they shall:

- Identify all applications received for REG connections
- Provide a forecast of anticipated future REG connections
- Identify the available system capacity to connect REG projects
- Discuss how any system constraints impact REG connection
- Discuss how any constraints affect any embedded distributors.

In Section 1 the quantity and size (MW) of current REG applications to PUC are identified. At present there are none.

A forecast for REG connections is provided in Section 2. PUC is anticipating the connection of one 250kW generator per year for a total connection of 1.25MW over the next 5 year period.

Section 3 covers how distribution system capacity is evaluated and provides a tabulated view of present available capacities on the main feeders and buses throughout the system. Adequate capacity is available to connect all forecast REG projects between 2023 and 2027.

Potential constraints and barriers to REG are considered in Section 4. Operational flexibility, protection, control and SCADA systems, how PUC participates in local and regional planning and PUCs REG objectives and strategies are all given consideration. Generally it is concluded that growth of REG on the PUC grid will not be constrained by any internal or regional factors.

Section 5 briefly states that there are no REG impacts to Embedded Distributors since none are connected to the PUC distribution system.

Section 6 concludes the report with a five year plan and investment strategy. It states that, the PUC grid is presently very well positioned to support all forecast REG connections over the next five years and no associated infrastructure investment is required during that period.

Contents

1 Applications for REG Connections

Activity with REG connections was significant prior to 2011 for PUC (61MW) but dropped off sharply thereafter with 1MW of interest in the five-year period between 2012 and 2017 and 0.09MW thereafter from 2018 through October 2021 as further detailed below.

1.1 Applications for REG Greater than 10kW

For REG generator connections greater than 10 kW, there are presently no applications to PUC. The connection history for all REG installations connected to the PUC distribution system over 10kW is illustrated in the table below. Of all the applications made, those that were not connected had applications terminated by the applicant and in no cases was unavailable capacity the deciding factor.

PUC Applications from Renewable Generators Over 10kW

	Application Date		Application MW		Connection Date		Connection MW	
Pre-2013	1985		0.25		1985		0.25	
	2008-01-08		0.037		2008-07-08		0.037	
	2007-07-24		0.045		2008		0.045	
	2007-04-15		9.95		2010-10-15		9.96	
	2007-04-17		9.95		2010-10-15		9.96	
	2007-06-03		9.95		2011-08-30		9.96	
	2007-06-03		9.95		2011-08-30		9.96	
	2007-06-03		9.95		2011-07-27		9.96	
	2007-06-03		9.95		2011-11-22		9.96	
	2007		9.95		N/A		0	
	2007		9.95		N/A		0	
	2011-09-09		0.035		2012-11-23		0.035	
	2011-06-07		0.5		2011-07-20		0.5	
	2011-09-26		0.25		2012-08-29		0.25	
	2011-02-28		0.1		2011-06-09		0.1	
	2011-06-14		0.135		2011-11-14		0.135	
	Quantity	16	Total MW	80.952	Quantity	14	Total MW	61.112
2013	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2014	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2015	2015-02-18		0.1		2016-08-23		0.1	
	Quantity	1	Total MW	0.1	Quantity	1	Total MW	0.1
2016	2016-06-23		0.07		2016-09-20		0.07	
	2016-03-11		0.25		2017-01-06		0.25	
	2016-03-11		0.25		2017-01-06		0.25	
	2016-03-11		0.25		2017-01-06		0.25	
	Quantity	4	Total MW	0.82	Quantity	4	Total MW	0.82
2017	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2018	2018-11-23		0.087		N/A		0	
	Quantity	1	Total MW	0.087	Quantity	1	Total MW	0
2019	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2020	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2021	Quantity	0	Total MW	0	Quantity	0	Total MW	0
2017-2021 Totals	Quantity	1	Total MW	0.087	Quantity	1	Total MW	0
Grand Total	Quantity	17	Total MW	81.039	Quantity	15	Total MW	61.112

Table 1 - Applications for REG Over 10kW

1.2 Applications for REG 10kW or less

Currently there are no applications in the queue from REG connections <10kW. Since the wind-down of the Micro-FIT program by the province, there appears to be a growing interest in net metering and some discussions about that in conjunction with energy storage behind the meter, however this has not materialized into any significant connected projects. There have been a total of six net metering <10kW connections totaling 41kW since 2016 and there are currently two connection applications totaling 14kW in progress for 2021.

2 Forecast REG Connections

2.1 Local Planning and Stakeholder Engagement

PUC interacts with the City of Sault Ste. Marie administration to coordinate infrastructure planning within its service territory, so that new connections to customers can be connected in a timely manner and projects involving line relocates to facilitate road widening projects can be planned. PUC staff attends formal meetings with the City and other municipal stakeholders and local utilities, annually, to review budgets and work plans for the coming year and the coming 5 years. Other 'ad hoc' coordination sessions occur on an 'as needed' basis with the stakeholders to look for synergies on specific projects and initiatives.

The annual coordination meetings are generally initiated by the City's administration and PUC along with other utilities that participate in them. For large commercial developments PUC participates in Development Assistance Review Team (DART) meetings on a regular basis for all large developments early in the planning stage. Additionally, PUC is included and invited to comment on all rezoning, severance and building applications allowing PUC to identify requirements early in the development stage. Inclusion in these processes assists PUC in understanding where and when projected developments will proceed and allows them to plan and size their infrastructure appropriately. Although detailed information about the upcoming projects is not always available five years in advance these consultations do provide qualitative indication of the volume of anticipated projects involving new customer connections, subdivision developments and line relocates. These meeting often offer at least some glimpse into potential for future REG projects and Smart Grid developments. At present there are no discussions indicating any REG projects are being proposed.

2.2 Five Year 2018-2022 REG Forecast

PUC has produced a 5 year forecast of future REG connections >10kW. For the period 2023-2027 projections have been based on:

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

Based on those factors, the five year forecast in Table 2 below has been established with an anticipated connection of one 100kW generator every second year for a total connection of 0.3MW over the next 5 year period.

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

Table 2 - Forecast REG for 2023-2027

3 System Capacity to Support REG

3.1 System Description

The distribution network owned and operated by PUC includes:

(a) **34.5 kV sub-transmission network –** consisting of nine 34.5kV feeders supplied from two 115kV Transformer Stations TS1 and TS2. The 34.5kV network supplies a total of twelve 34.5/12.47kV stations, one 34.5/4.16kV station, and one 34.5/12.47&4.16kV station and a number of large industrial customers. Much of the 34.5kV network is connected in a looped type configuration affording a high degree of operating flexibility during contingencies. The 34.5kV network also provides connections to six ~ 10MW solar generation stations.

(b) **12.47 kV distribution network –** consisting of approximately 50 feeders supplied from twelve municipal stations. With the exception of two stations that have 2x7.5MVA transformer capacity, the remaining stations are equipped with 2x10MVA transformers. 336kcmil or 3/0AWG conductor size is typically employed on feeder trunk lines and the average length of the trunk section of 12.47kV feeders is approximately 10 km.

(c) **4.16 kV distribution network** – PUC has been gradually upgrading the 4.16kV network to 12.47kV, but there are still two 4.16kV stations in service supplying three feeders. The average length of the trunk section of the 4.16kV feeders is approximately 5km. A majority of the trunk lines employ a conductor size of 3/0AWG or 336kcmil. This infrastructure will be fully phased out and upgraded to 12.47kV by 2023.

3.2 Short Circuit Capacity

One consideration for the interconnection of REG projects to the distribution system is to determine the impact of introducing a new source of fault current. On a given feeder it is necessary to conduct a full review on the various system components such as conductors, insulators, switches, breakers and transformers to determine if there are any exceedances.

Through software based system modelling and engineering studies PUC Engineering has arrived at the conclusion that solar PV embedded generation has negligible system impact from this perspective. Typical solar panel inverter fault currents are in the order of 105% to 125% of the inverter nameplate and cease to generate fault current within 30ms.

On PUCs 34.5kV system, all equipment has withstand and interrupting ratings of 25kA or higher and typical pre-REG system fault levels are typically 19kA and lower. In connecting six 10MW facilities circa 2010-2011, connection impact assessments (CIAs) were completed and it was determined at that time that any connection scenario for inverter based DG that respected thermal circuit limits would inherently respect short circuit interrupting and withstand ratings for all equipment.

Similar observations have been made and conclusions drawn on the 12kV system where withstand and interrupting ratings are again 25kA but fault levels are most typically 11kA or less with the exception of Sub 19 which is closer to 17kA.

PUC has not yet been asked to connect any REG customers >10kW to the 4.16kV distribution system and it has not been reviewed comprehensively. However, in the majority of areas a 12kV circuit is almost always in place as an alternative and, where not, it would be possible to accelerate part of the voltage conversion program in short order to make a 12kV connection point available.

3.3 Thermal Capacity and Circuit Loading

All of PUCs 34.5kV circuits have a nominal rating of 600A and a thermal limit of approximately 35MVA/30MW. PUC has successfully studied and connected 20MW of solar generation on one 34.5kV feeder. Similar results would be expected on any of the remaining systems feeders as their characteristics are much the same.

A number of research projects undertaken by various organizations in Canada and USA have focused on the maximum allowable penetration levels of embedded generation from renewables that could be connected to distribution feeders without adverse impacts on reliability, power quality and stability. There is consensus among experts that distributed generation capacities up to the minimum feeder load levels during light load conditions generally have beneficial impacts on power quality and load flows. Most experts agree that solar power penetration rates of up to approximately 25%-30%, where penetration rate is defined as the AC output of Embedded Generating Plant divided by the Peak Load Capacity of Distribution System, do not result in adverse impacts on operating performance [Reference: High Penetration of Photovoltaic (PV) Systems into the Distribution Grid – Workshop Report" U.S. Department of Energy 2009].

PUCs 12.47kV circuits have a nominal rating of 300A(6.5MVA) with a target load operating range between 150A-200A(3.3-4.4MVA). Following the recommendations discussed above, a rule of thumb has been established that 1MW of solar PV can be safely integrated on a typical 12kV feeder although a case by case CIA is always required.

3.4 Available System Capacity

Primarily based on thermal ratings of conductors and transformers, PUC has developed and submitted to the IESO, the following table of available capacity. The IESO uses this for planning and as an input to preparing a Transmission Availability Table (TAT) which is posted online to assist prospective REG applicants in selecting a site for their project. Table 3 summarizes available capacity at the 34.5kV feeder and station bus levels. It can be seen that at present there is still capacity available for the future connection of approximately 27MW more generation between circuits out of TS1 and TS2 combined.

It is noted here that feeders SM-5, 7, 9 and 11 are shown as having only 3.7MW each of remaining capacity however those capacities are based on the limiting factor of the upstream 115kV/35kV transformers at TS1 which have a combined limit of 45MW. The limit of 45MW less the existing connected 41.3MW REG leaves the possibility of connecting a combined total of 3.7MW in any combination on those four feeders. So although each of the four feeders have 20MW of available thermal capacity, they are limited by the fact that the station transformer remaining capacity is lower. Based on the projected connections for the next five years, this does not represent a system constraint.

Station	Bus Name	Capacity (MW)	Allocated Capacity (MW)	Available Capacity (MW)	Supply Circuit 1	Supply Circuit 2
TS1	**Total**	**45**	**41.328**	**3.672**	**GL1SM**	**GL2SM**
(St. Mary's)	West	30	21.009	3.672		
	East	30	20.318	3.672		
TS2	**Total**	**45**	**21.663**	**23.337**	**GL1TA**	**GL2TA**
(Tarentorus)	West	30	21.015	8.985		
	East	30	0.647	23.337		

34.5 kV Feeder Name	Bus Connection	Capacity (MW)	Allocated Capacity	Available Capacity (MW)	Notes:
SM-5	West	30	10.214	3.672	TS Limiting (45-D5) MW
SM-7	West	30	9.960	3.672	TS Limiting (45-D5) MW
Sub 19 West	West	N/A	0.835	N/A	no feeder, direct bus connection
SM-9	East	30	10.034	3.672	TS Limiting (45-D5) MW
SM-11	East	30	10.034	3.672	TS Limiting (45-D5) MW
Sub 19 East	East	N/A	0.250	N/A	no feeder, direct bus connection
TS1			**41.328**		
TA-6	West	30	0.139	23.337	TS Limiting (45-D8) MW
TA-7	West	30	20.876	8.985	West Bus Limiting (30-D9) MW
TA-9	East	30	0.028	23.337	TS Limiting (45-D8) MW
TA-10	East	30	0.188	23.337	TS Limiting (45-D8) MW
TA-11	East	30	0.431	23.337	TS Limiting (45-D8) MW
TS2			**21.663**		

Table 3 - PUC Available Capacity

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

4 Constraints to REG Connections

4.1 PUC Distribution Inc. Long term Planning

Support for REG and smart grid is integral to the long term planning processes employed by PUC. In 2009 in response to enactment of the Green Energy Act, PUC Engineering identified a set of strategies that would support the REG/Smart Grid objectives of the Act while bringing value to its customers (see Figure 1 - Smart Grid and REG Objectives and Strategies). This set of strategies has served as a foundation for past capital investments, and the bulk of the strategies have been implemented to completion removing barriers to future REG investments.

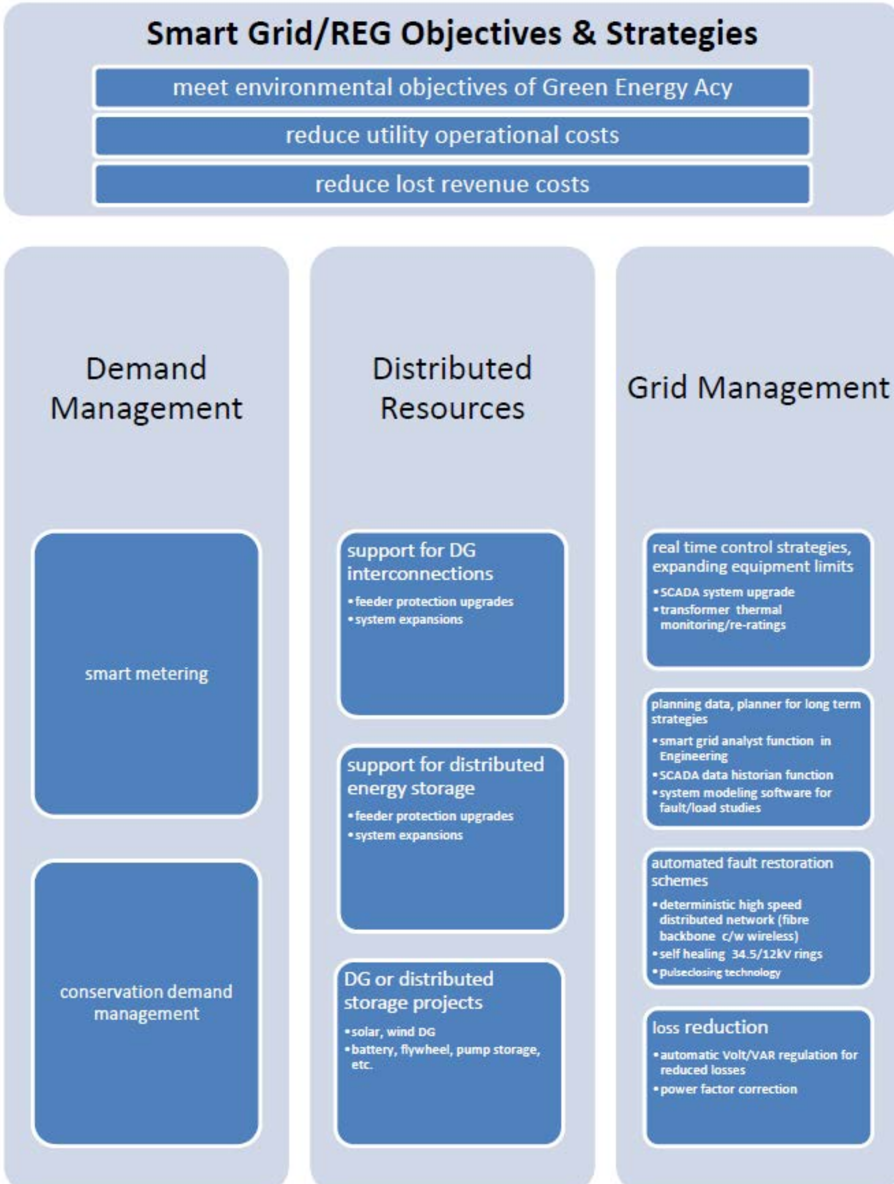


Figure 1 - Smart Grid and REG Objectives and Strategies

4.2 Operational Flexibility

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

4.3 Protection, Control, and SCADA

The introduction of REG resources introduces the potential for reverse power flow conditions, reduced relay sensitivity to trip during fault conditions, power quality and voltage regulation. Solutions to these problems call for fast and advanced modern microprocessor based and communications enabled protection, control and SCADA equipment. PUC anticipated these needs amongst others such as reliability and embarked on a number of initiatives over the past 10 years that will benefit REG and smart grid deployments now and in the future:

- A major upgrade of the PUC SCADA core components and implementation of a data historian (2008 – 2011)
- Deployment of an Ethernet based communications backbone over modern fibre-optic and radio platforms to support protection, control, SCADA, telemetry, metering, and enterprise network functions. Support for anticipated forthcoming NERC cybersecurity requirements is built in. (2010-2018)
- Upgrade of protective relaying at TS1, TS2 and all 12kV stations not slated for rebuilds or retirement in the next 5 years to microprocessor based, IP communications based equipment capable of full REG support (2008 – 2022)
- The Sault Smart Grid (SSG) Project is planned for 2021-2022 will bring Volt/VAR optimization to every 12.47kV feeder, as well as automated system restoration and fault isolation, and an upgraded SCADA/OMS system for in depth system analysis

4.4 Regional Infrastructure Planning

PUC belongs to the "East Lake Superior Region (ELS-Region)" planning team, for which former Great Lakes Power Transmission (GLPT), now Hydro One Networks is the lead transmitter and responsible party for steering the regional planning in this region.

In response to the OEB Regional Infrastructure Planning (RIP) process approved in 2013, development of an Integrated Regional Resource Plan (IRRP) was triggered by the IESO in April 2019 and will be completed in 2021. PUC participated in the planning process and provided required data to HONI and the IESO. The scope of this planning initiative was to identify critical infrastructure needs of the transmission grid during the next 20 years beginning in 2020. The assessment included a review of transmission system connection facilities capacity which covers station loading, thermal and voltage analysis, system reliability, operational issues such as load restoration and asset sustainment plans. The results will be made available by the IESO when the ELS-Region IRRP is finalized.

The report shows a modest decline in load for the PUC over the study period and only nominal growth for the region. No constraints or barriers to REG growth for the PUC service territory are anticipated as a result of the regional factors considered.

5 Constraints to Embedded Distributors

PUC has no embedded distributors therefore does not contribute to any associated REG constraints.

6 Proposed Plan and Investments to Support REG

Due to the Sault Smart Grid (SSG) project and investments over the past 10 years primarily in protection, control, SCADA and communications infrastructure, PUC is well positioned to support a broad range of REG and smart grid initiatives. PUC can also say with confidence that past investments along with currently available capacity will allow the connection of all forecast REG projects for the next five years with no need for additional system investments.

Appendix G

IESO Comment Letter

IESO response to PUC Distribution Inc.'s REG Investments Plan 2023 – 2027

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricty System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan. On October 26, 2021, PUC Distribution Inc. (PUC) sent its REG Investments Plan to the IESO for comment. The IESO has reviewed PUC's REG Investments Plan and notes that it contains no investments specific to connecting REG for the plan period 2023 - 2027.

The IESO notes that PUC's service territory is within the East Lake Superior Region. The IESO confirms that PUC participated with the Study Team for this region.[1] The IESO reports that regional planning is complete in the East Lake Superior Region, with the publication of the Integrated Regional Resource Plan (IRRP) on April 1, 2021.[2]

The Needs Assessment for the East Lake Superior region was published by Hydro One Networks Inc. on June 14, 2019 indicating further regional planning was required for the region.[3] The IESO's Scoping Assessment Outcome Report outlining the planning approach for the region, and related Terms of Reference, was published on October 3, 2019. [4]

PUC's REG Investments Plan Section 6: Proposed Plan and Investments to Support REG states:

> *"Due to the Sault Smart Grid (SSG) project and investments over the past 10 years primarily in protection, control, SCADA and communications infrastructure, PUC is well positioned to support a broad range of REG and smart grid initiatives. PUC can also say with confidence that past investments along with currently available capacity will allow the connection of all forecast REG projects for the next five years with no need for additional system investments."*

The IESO submits that as PUC has no REG investments planned at this time nor forecast during the 5-year Distribution System Plan period, no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties.[5]

The IESO appreciates the opportunity provided to review the REG Investments Plan of PUC Distribution Inc. and looks forward to working together in future regional planning processes.

---

[1] East Lake Superior Region Study Team members include the IESO and Hydro One Networks Inc. (Distribution and Lead Transmitter), PUC Distribution Inc., Algoma Power Inc. and Hydro One Sault Ste. Marie LP

[2] IESO, East Lake Superior Region IRRP, April 1, 2021: East Lake Superior (ieso.ca)

[3] Hydro One Networks Inc., East Lake Superior Needs Assessment, June 14, 2019: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/eastlakesuperior/Documents/Needs%20Assessment%20Report%20-%20East%20Lake%20Superior%20Region%20(2019-06).pdf

[4] IESO, East Lake Superior Region Scoping Assessment, October 3, 2019: East Lake Superior (ieso.ca)

[5] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

Appendix H

Asset Condition Assessment

METSCO

MAKING IT POSSIBLE

<page left blank intentionally>

ASSET CONDITION ASSESSMENT FINAL REPORT 2021

Prepared by

METSCO Report no. P-21-126-R1

May 2022

Disclaimer

This 2021 report has been prepared by METSCO Energy Solutions Inc. ("METSCO") for PUC Distribution Inc. ("PUC"). Neither PUC, nor METSCO, nor any other person acting on their behalf makes any warranty, expressed or implied, or assumes any legal responsibility for the accuracy of any information or for the completeness or usefulness of any process disclosed or results presented, or accepts liability for the use, or damages resulting from the use, thereof. Any reference in this report to any specific process or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement or recommendation by PUC or METSCO.

Asset Condition Assessment Report 2021
Final Report

September 2021

Experts: Kurtis Martin-Sturmey, P.Eng.

Pranav Pattabi, P.Eng., M.Eng.

Expert Support: Hassan El Bassuoni

Samer Anabtawi

Approved By: Alex Ferguson

Revision History

2022-05-30	R1	Rev. 1 (Minor Edits)	AF	LT	AF
2022-01-14	R0	Rev. 0	HE	KMS	AF
2021-09-10	IFR	Issued for Review	HE/SA/PP	KMS	AF
Date	**Rev.**	**Status**	**By**	**Checked**	**Approval**

Executive Summary

Context of the Study

PUC Distribution Inc. ("PUC") is an electricity distributor serving approximately 33,750 residential and commercial customers in the City of Sault Ste. Marie, the Batchewana First Nation (Rankin Reserve), Prince Township, and parts of Dennis Township. PUC operates a system made up of 15.5 km of overhead 115kV transmission, 99 km of 34.5-kV subtransmission, and 623 km of distribution lines and cables (12.47 kV and below). PUC also owns and operates assets at two Transmission Stations ("TS") and fourteen substations.

PUC engaged METSCO Energy Solutions Inc. ("METSCO") to prepare a comprehensive Asset Condition Assessment ("ACA") study for the assets comprising PUC's distribution system. The ACA is required as one of the key inputs for the preparation of PUC's five-year Distribution System Plan ("DSP"), developed in accordance with the filing requirements for electricity distributors enacted by the Ontario Energy Board ("OEB"). The scope of the ACA covers PUC-owned assets for all subtransmission and distribution lines/cables, fourteen substations, and two TS but does not cover the 115-kV transmission line assets. It is recommended to perform a separate study to assess the condition of the transmission lines.

Scope of the Study

METSCO's work included interviews with PUC subject matter experts to define the Health Indices ("HI") appropriate for the asset types, review and consolidation of the client's data sets, analysis of PUC's asset records to calculate the HI values, and preparation of the final document. In total METSCO assessed and calculated HI values for the following asset classes:

- Distribution Wood Poles
- Underground Primary Cables
- Distribution Transformers (Pole-mount, Pad-mount, or Submersible)
- Pad-mount Distribution Switchgear
- Underground Switches (Junction Boxes)
- Station Power Transformers
- Medium-Voltage Station Switchgear
- 34.5-kV TS Circuit Breakers
- Station Battery Banks and Chargers

- Station Building Facilities
- Station Riser Cables

For asset classes with not enough information to calculate HI, METSCO created age assessments to summarize the age profile of those asset classes. The following asset classes are included as part of age assessments but do not have calculated health indices:

- Distribution Steel Poles
- Overhead Primary Conductors
- Fused Disconnect Switches (Cut-outs)
- Load-Break Switches
- Station Service Transformers

All asset condition data used in the study is maintained by PUC as part of its regular asset management practices. The ACA results are based on condition data recorded by PUC and its contractors up to September 2021. This information was provided to METSCO between May and September 2021.

To supplement the information provided by PUC, METSCO conducted a site visit in August 2021 to assess the condition of PUC's TS and substations, focusing on power transformers, 34.5-kV TS circuit breakers, station buildings, and station fences. The site visit involved a visual inspection and infrared ("IR") scan. In addition, METSCO assessed the condition of PUC's medium-voltage switchgear, battery banks, and chargers based on photos and IR scans obtained by PUC.

Methodology and Findings

For all asset classes that underwent assessment, METSCO used a consistent scale of asset health from Very Good to Very Poor. The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, expressed as a percentage. Table 0-1 presents the HI ranges corresponding to each condition score, along with their corresponding implications as to the follow-up actions required by the asset manager at PUC.

Table 0-1: Health Index Ranges and Corresponding Implications for the Asset Condition

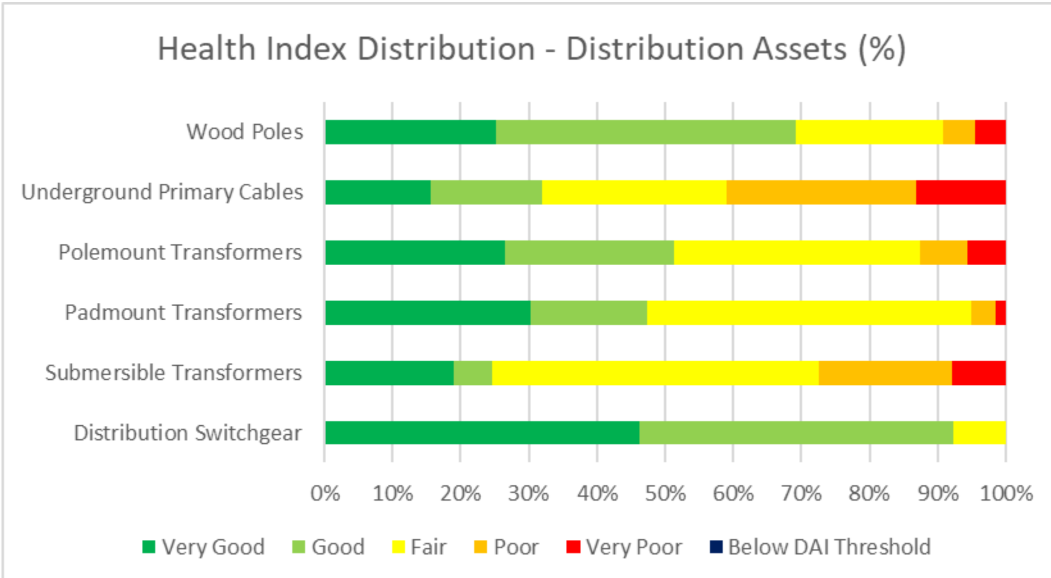
Health Index Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

Using this scale, METSCO calculated the HI for every asset in the scope of the assessment using the applicable and available "condition parameters" – individual characteristics of the state of an asset's components. Each condition parameter has its own sub-scale of assessment and a weighting contribution that represents the percentage in the overall HI made up by the parameter. METSCO's findings for each asset class were developed using this methodology, as described in more detail in Section 3 and Section 4.

The consolidated results of the ACA for distribution assets are summarized in

Figure 0-1. The HI is not calculated for any distribution asset with a Data Availability Indicator ("DAI") less than 70% (i.e., less than 70% of the condition parameters – by weight – are available for that asset) or less than 65% for station assets. The HI results for assets with a known HI were divided into ten-year bands and extrapolated to the unknown set within those bands.

Figure 0-1: Distribution Asset Health Index Results – Extrapolated

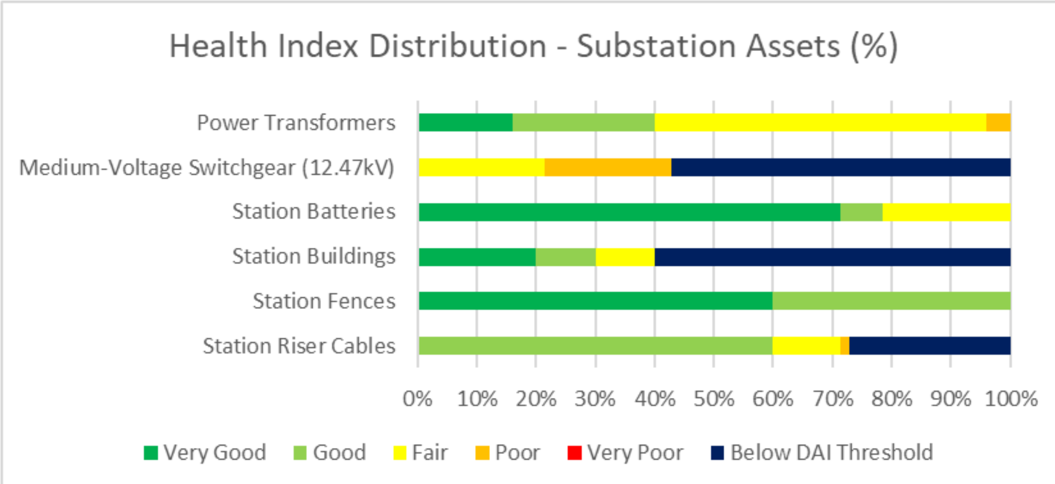


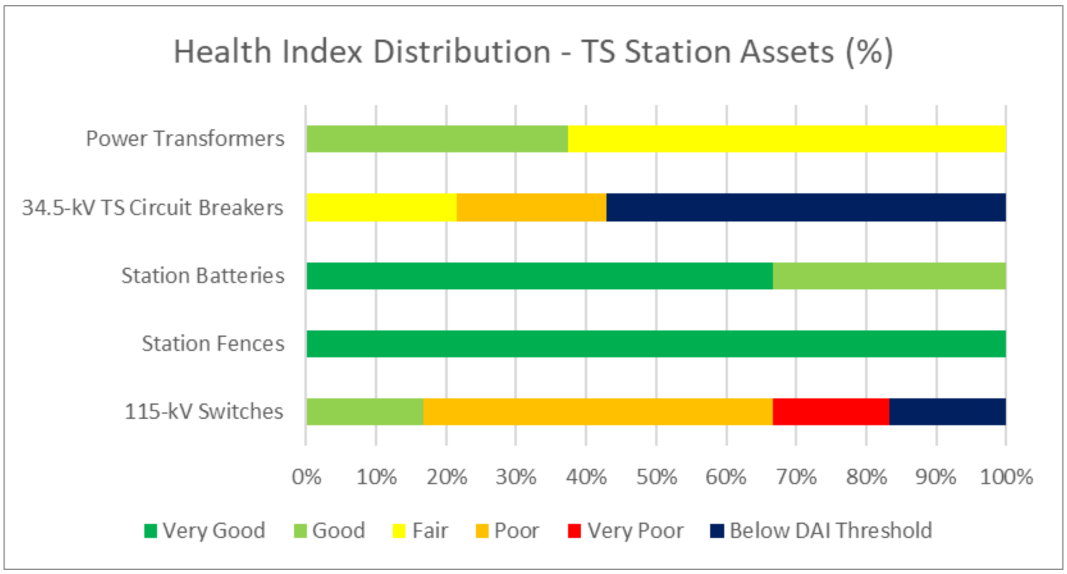
As

Figure 0-1 indicates, there are a significant number of assets in Fair condition that will require intervention over the long-term and may require intervention in the short-term depending on risk. In particular, Poor or Very Poor condition assets have been identified across the system which should be assessed for replacement or refurbishment over the short-term.

Figure 0-2 summarizes the ACA results for PUC's station assets. Due to the much smaller asset population compared to distribution assets, the HI results for station assets are not extrapolated when the DAI is insufficient to calculate a valid HI.

Figure 0-2: Station Asset Health Index Results





As Figure 0-2 indicates, there are a significant number of assets – in particular, 115-kV switches, power transformers, medium-voltage switchgear, and 34.5-kV circuit breakers – in Fair condition that will require intervention in the long-term and may require intervention in the short-term depending on risk. Stations assets serve many downstream customers and are generally higher risk compared to distribution assets. There are also several assets in Poor condition that will require intervention in the short-term.

Table 0-2: Asset Condition Assessment Overall results

presents the numerical HI summary for each asset class. The HI distribution is based on the total population count of a given asset class. For each asset class, the population, average HI, average DAI, and HI distribution are listed.

Table 0-2: Asset Condition Assessment Overall results

Asset Class	Population	Health Index Distribution (%)					
		Very Good	Good	Fair	Poor	Very Poor	Below DAI Threshold
Distribution Assets							
Wood Pole	12,548	25.13%	44.08%	21.51%	4.70%	4.57%	
Steel Pole	57	Age Only					
Overhead Primary Conductor	614.9 km	Age Only					
Underground Primary Cable	123 km	15.60%	16.42%	26.99%	27.79%	3.21%	
Pole-Mount Transformer	4806	26.57%	24.69%	36.23%	6.85%	5.67%	
Pad-Mount Transformer	939	30.22%	17.20%	47.59%	3.49%	1.50%	
Submersible Transformer	468	19.01%	5.55%	48.08%	19.44%	7.91%	
Distribution Switchgear	25	48.00%	48.00%	4.00%	0.00%	0.00%	
Fused Switches	1536	Age Only					
Disconnect Switches	905	Age Only					
Substation Assets							
Power Transformer	26	12.12%	27.27%	57.58%	3.03%	0.00%	
Medium Voltage Switchgear (12.47-kV)	13	0.00%	0.00%	21.43%	21.43%	0.00%	57.14%
Medium Voltage Switchgear (4.16-kV)	3	Age Only					
Medium Voltage Switchgear (34.5-kV)	14	Age Only					
Station Service Transformer	17	Age Only					
Substation Battery	14	71.43%	7.14%	21.43%	0.00%	0.00%	
Substation Buildings	10	20.00%	10.00%	10.00%	0.00%	0.00%	
Station Fences	14	60.00%	40.00%	0.00%	0.00%	0.00%	
Station Riser Cables	94	0.00%	60.00%	11.43%	1.43%	0.00%	27.14%
TS Assets							
Power Transformer	8	0.00%	37.50%	62.50%	0.00%	0.00%	
34.5-kV TS Circuit Breaker	22	0.00%	0.00%	22.73%	22.73%	0.00%	54..54%
Station Battery	3	66.67%	33.33%	0.00%	0.00%	0.00%	
Station Fences	2	100.00%	0.00%	22.73%	22.73%	0.00%	
115-kV Switches	12	0.00%	16.67%	0.00%	50.00%	16.67%	16.67%

PUC's Current Health Index Maturity and Continuous Improvement

Overall, PUC's asset data collection practices are sufficiently robust to enable calculation of the recommended ACA that is consistent with industry best practices. The average DAI scores are very high across most asset classes. Asset condition information is unavailable for steel poles, overhead transformers, fused and load-break switches, and station service transformers – all of which have been assessed based on age only. Notably, among the assets with HI scores, submersible transformers and station riser cables have the most room for improvement in DAI and should receive increased attention over the next maintenance cycle.

While the HIF formulation and DAI have been determined based on available condition parameters, there are opportunities for PUC to introduce additional variables that can provide further insight into the degradation level of a given asset class. For example, visual inspection results would aid the assessment of station riser cables and detailed loading history could be used to assess the condition of primary cables.

While the existing framework provides PUC with a significant volume of data, certain procedural and technological enhancements could further the granularity of its asset condition data and facilitate calculation of a greater proportion of numerical degradation scores. For example, PUC's maintenance database is not coordinated with its Geo-spatial Information System ("GIS") in some cases. Furthermore, routine inspections done by PUC could be used as an opportunity to collect condition information for long-term planning in addition to identifying corrective maintenance needs.

In providing these recommendations, METSCO is cognizant of the fact that regulated utilities are facing cost constraints across numerous facets of their operations, while contending with the effects of aging infrastructure, changing climate, evolving customer needs, and many other priorities. As such, an adoption of any incremental enhancement to the existing asset data collection practices must be grounded in management's assessment of the incremental value of such enhancements, relative to the opportunity cost of advancements elsewhere in the utility's operations. METSCO makes this observation to highlight its position that the sole fact of a gap between a utility's current process state and the industry best practices need not necessarily indicate that an action to remedy that gap is required in short order.

Table of Contents

List of Figures

List of Tables

1 Introduction

METSCO Energy Solutions Inc. ("METSCO") is an industry expert in Asset Condition Assessment ("ACA") and Asset Management ("AM") practices due to our extensive experience in conducting ACAs, developing AM plans, and implementing AM frameworks for transmission and distribution utilities across North America. METSCO's collective record of experience in these areas is among the most extensive in the world, with our AM frameworks gaining acceptance across multiple regulatory jurisdictions. A selection of METSCO's past projects is attached as Appendix A to this report.

PUC Distribution Inc. ("PUC") is an electricity distributor operating in the City of Sault Ste. Marie, the Batchewana First Nation (Rankin Reserve), Prince Township, and parts of Dennis Township. PUC engaged METSCO to prepare a comprehensive ACA study for the assets comprising PUC's electrical system. The ACA is required as one of the key inputs for the preparation of PUC's five-year Distribution System Plan, prepared in accordance with the filing requirements enacted by the Ontario Energy Board ("OEB"). The study's primary objective is to objectively determine the condition of PUC's assets as a key step in the capital expenditure process for renewal investments. Supplementary objectives include preparing the ACA results to be used for PUC's upcoming rate filing as well as to continuously improve PUC's AM framework.

A unique ACA methodology is applied to each asset class deployed within PUC's system. The adoption of the ACA methodology requires identifying end-of-life criteria for various components associated with each asset type, followed by periodic asset inspections and recording of asset condition to identify the assets most at risk at reaching the end-of-life criteria over the planning horizon. Each criterion represents a factor that is influential, to a specific degree, in determining an asset's (or its component's) condition relative to its potential failure. These components and tests are weighted based on their importance in determining the assets' end-of-life.

The assets covered in the report include the following major asset classes:

- Wood Poles
- Overhead Primary Conductors
- Underground Primary Cables
- Distribution Transformers (Pole-mount, Pad-mount, or Submersible)
- Pad-mount Distribution Switchgear

- Fused Disconnect Switches (Cut-outs)
- Load-Break Switches
- Underground Switches (Junction Boxes)
- Station Power Transformers
- 115-kV Station Switches
- 34.5-kV Station Circuit Breakers
- Medium-Voltage Station Switchgear (34.5 kV, 12.47 kV, or 4.16 kV)
- Station Service Transformers
- Station Battery Banks and Chargers
- Station Building Facilities
- Station Fences
- Station Riser Cables

All the asset condition data is maintained by PUC as part of its regular AM and maintenance practices. All condition information was collected by PUC and its contractors up to September 2021. This data was transmitted to METSCO between May and September 2021 to complete the ACA.

Major assets which do not fall within the scope of this assessment include:

- 115-kV transmission lines (structures, conductors, insulators, skywires, hardware, guywires, grounding, etc.)
- SCADA and communications systems
- Station grounding system (grid, bonding, etc.)
- Secondary bus and service conductors/cables
- Office buildings and facilities

To supplement the information provided by PUC, METSCO conducted a site visit in August 2021 to assess the condition of PUC's TS and substations, focusing on power transformers, outdoor circuit breakers, station buildings, and station fences. The site visit involved a visual inspection and infrared ("IR") scan. In addition, METSCO assessed the condition of PUC's medium-voltage switchgear, battery banks, and chargers based on photos and IR scans obtained by PUC.

The report is organized into six sections including this introductory section:

- Section 2 summarizes the ISO 5500X AM standards, discusses how the ACA fits into the overall AM framework; and provides an overview of METSCO's ACA methodology;
- Section 3 summarizes the asset Health Index ("HI") calculation methodology;
- Section 4 provides the Condition Assessment methodology framework and assessment for each of the identified asset classes;
- Section 5 provides METSCO's conclusions; and
- Section 6 summarizes METSCO's recommendations for PUC on data collection improvements for continuous improvement efforts for the ACA.

2 Context of the ACA within AM Planning

The ACA is a key step in developing an asset replacement strategy. By evaluating the current set of available data related to the condition of in-service assets comprising an organization's asset portfolio, condition scores for each asset are determined. The ACA involves the collection, consolidation, and utilization of the results within an organizational AM framework for the purposes of objectively quantifying and managing the risks of its asset portfolio. The level of degradation of an asset, its configuration within the system, and its corresponding likelihood of failure feed directly into the risk evaluation process, which identifies asset candidates for intervention (i.e., replacement or refurbishment). Assets are then grouped into program and project scopes that are evaluated and prioritized.

The ACA is designed to provide insights into the current state of an organization's asset base, the risks associated with identified degradation, approaches to managing this degradation within the current AM framework, and how to best make use of these results to extract the optimal value from the asset portfolio going forward.

2.1 International Standards for AM

The following paragraphs serve as a brief introduction to the ISO standards and provide a brief overview of the applicability of AM standards within an entity.

The industry standard for AM planning is outlined in the ISO 5500X series of standards, which encompass ISO 55000, ISO 55001, and ISO 55002. Each business entity finds itself at one of the three main stages along the AM journey:

1. Exploratory stage - entities looking to establish and set up an AM system;
2. Advancement stage - entities looking to realize more value from an asset base; and
3. Continuous improvement stage - those looking to assess and progressively enhance an AM system already in place for avenues of improvement.

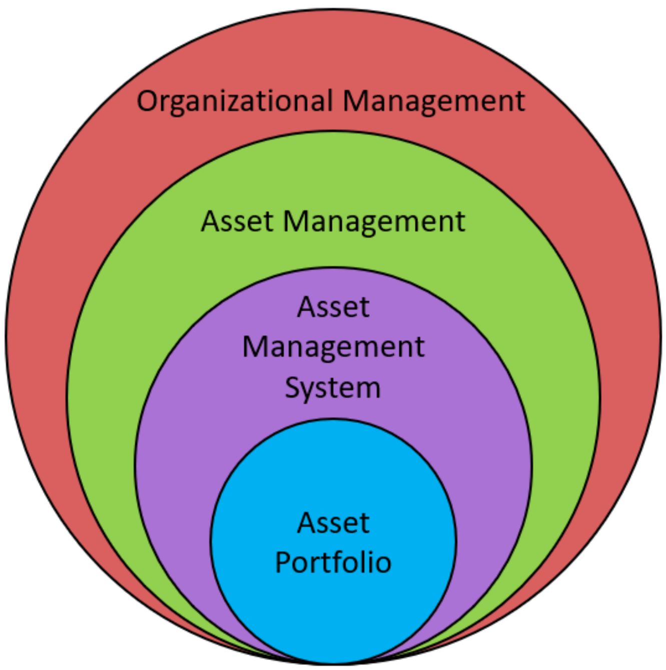
Given that AM is a continuous journey, ISO 5500X remains continuously relevant within an organization; providing an objective, evidence-based framework against which the organizations can assess the managerial decisions relating to their purpose, operating context, and financial constraints over the different stages of their existence.[1]

[1] ISO 55000 – Asset management – Overview, principles and terminology

An asset is any item or entity that has a value to the organization. This can be actual or potential value, in a monetary or otherwise intangible sense (e.g., public safety). The hierarchy of an AM framework begins with the asset portfolio, containing all known information regarding the assets, sits as the fundamental core of an organization. The ACA is the procedure to turn the known condition information into actionable insights based on the level of deterioration.

Around the asset portfolio, the AM system operates and represents a set of interacting elements that establish the policy, objectives, and processes to achieve those objectives. The AM system is encompassed by the AM practices – coordinated activities of the organization to realize maximum value from its assets. Finally, the organizational management organizes and executes the underlying hierarchy.[1]

Figure 2-1: Relationship between Key AM terms[1]



2.2 ACA within the AM Process

A well-executed AM strategy hinges on the ability of an organization to classify its assets via comprehensive and extensive data and data collection procedures. This includes but is not limited to:

- Collection and storage of technical specifications;
- Historical asset performance;
- Projected asset behaviour and degradation;
- Configuration of an asset or asset-group within the system; and
- Operational relationship of one asset to another.

In this way, AM systems should be focused on the techniques and procedures in which data can be most efficiently extracted and stored from its asset base to allow for further analysis and insights to be made. With more asset data on hand, better and more informed decisions can be made to realize greater benefits and reduce the risk across the asset portfolio managed by an organization.[2]

AM is fundamentally grounded in a risk-based evaluation of continued value. The overarching goal of an AM process is to quantify all assets risk by their probability and impact (where possible) and then look to minimize these risks through AM operations and procedures. The ACA quantifies the condition of each asset under study and is an appropriate indicator of its failure probability. Making asset replacement decisions directly based on the ACA results constitutes a condition-based intervention strategy.

AM practices can help quantify and drive strategic decisions. A better understanding of the asset portfolio and how it is performing within an organization will allow for optimal decision-making. This is largely due to best AM practices being a fundamentally risk-based approach, which lends it to be a structured framework for creating financial plans driven by data. AM practices should also have goals in mind when framing asset investments, changes in asset configuration, or acquisition of new assets. This can include better technical compliance, increased safety, increased reliability, or increased financial performance of the asset base. ISO 55002 states explicitly that all asset portfolio improvements should be assessed via a risk-based approach prior to being implemented.[2] The criticality of the asset determines its failure impact. A risk-based asset intervention strategy should consider both the probability and impact in the decision-making process.

2.3 Continuous Improvement in the AM Process

The application of rigorous AM processes can produce multiple types of benefits for an organization including, but not limited to: realized financial profits, better classified and managed risk among assets, better-informed investment decisions, demonstrated

[2] ISO 55002 – Asset management – Management systems – Guidelines for the application of ISO 55001

compliance among the asset base, increased public and worker safety, and corporate sustainability.[1]

AM processes are ideally integrated throughout the entire organization. This requires a well-documented AM framework that is shared between all relevant agents. In this way, the organization stands to benefit the most from its internal resources, whether it be via technical experts, those operating and maintaining the assets or those with an understanding of the financial operations and constraints on the organization. As a future-state goal, utilities and other organizations alike should strive to document their AM guiding principles within a Strategic Asset Management Plan ("SAMP"). The SAMP should be used as a guide for the organization to apply its AM principles and practices for its specific use case. Distribution of the SAMP should be well-publicized within an organization and updated on a regular basis, to best quantify the most current and comprehensive AM practices being implemented. Just as the asset base performance is subject to an in-depth review, the AM process and system should be reviewed with the same rigor.[1]

AM should be regarded as a fluid process. Adopting a framework and an idealized set of practices does not bind the organization or restrict its agency. With time, the goal of any AM system is to continually improve and realize benefits within the organization through better management of its asset portfolio. Continually improved asset data and data collection procedures, updated SAMPs, and further integration into all aspects of an organization's activities as it grows and changes over time should be the goal of any AM framework.[2]

3 Asset Condition Assessment Methodology

3.1 METSCO's Project Execution

METSCO's execution path in completing the ACA study can be is a four-phase procedure:

1. *Initial information gathering*: including initial interviews with PUC staff to investigate system configuration and the prominence of certain asset classes, establish the range of available condition data sources at the beginning of the engagement, and confirm the key assumptions regarding these factors with PUC subject matter experts through a series of interviews.

2. *Remote condition assessment* – follow-up review of asset photos and IR scan results for medium-voltage circuit breakers, station batteries, and chargers to assess their condition based on METSCO's established criteria.

3. *On-site inspections* – follow-up site visit to visually inspect and IR scan PUC's power transformers, high-voltage oil circuit breakers, station buildings, and station fences.

4. *Database construction* – activities to construct a single database of condition-related information for each PUC asset class using the provided data sources. This includes consolidation of PUC's asset inspection records, databases containing results of technical tests performed by PUC contractors, and the entire database from the Geographic Information System ("GIS").

5. *HI and Data Availability Index ("DAI") calculation* – upon confirming the integrity of its condition dataset along with the accuracy of assumptions made in its preparation, METSCO calculated the Health Indices and DAI for all asset classes. Additional data sources were requested from PUC to improve the accuracy of the asset health calculation if applicable.

6. *Results Reporting* – the final phase of the project scope was the creation of the ACA report.

3.2 Data Sources

To assess the demographics and establish the unit population of PUC's system assets, METSCO was provided with PUC's asset demographic data from its current Geographic

Information System ("GIS"). These data came from PUC's corporate asset registries containing information on asset vintage, model, and year of commissioning. The database served as the primary asset library that contained asset nameplate information such as age and unique identifiers.

To assess the condition of PUC's system, METSCO was provided with available asset inspection and maintenance data for the asset classes in scope. Various sources hold records of PUC's inspection and maintenance activities. Most of these data came from primary sources such as equipment inspection forms completed by PUC staff or contractors, or the results of specific tests such as the Dissolved Gas Analysis ("DGA") for station power transformer oil.

Additionally, METSCO was provided with historical operating data for assets that require operating information for the HI calculation. An example of operating data used is the historical loading information for transformers.

3.3 Asset Condition Assessment Methodologies

Prior to completing an ACA, a methodology needs to be selected for the current entity. The four most common methodologies that can be employed to assess the condition of the system health include:

1. Additive models – asset degradation factors and scores are used to independently calculate a score for each individual asset, with the HI representing a weighted average of all individual scores from 0 to 100;
2. Gateway models – select parameters deemed to be most impactful on the asset's overall functionality act as "gates" to drive the overall condition of an asset, by effectively "deflating" the scores of other (less impactful) components;
3. Subtractive models – consider that a relatively Poor condition for any of several major assets within a broader system of assets could act as a sufficient justification to drive investments into the entire system; and
4. Multiplicative models – a HI that dynamically shifts the calculation towards specific degradation factors, if they are a leading indicator to show that an asset is failing.

The additive and gateway models are typically used for assessing individual assets, whereas the subtractive and multiplicative models are typically used for aggregate and composite system-level assessments. The latter models are still in an early stage and require extensive refinement and validation to confirm their applicability. The gateway model assigns gates to criteria or asset subcomponents which are difficult or expensive to replace and maintain, and/or are known to be a major cause of asset malfunctioning. This methodology is commonly used in conjunction with the additive model for major assets such as wood poles, where a "gate" score will act to reduce the HI due to a low recorded score for a given criterion. For example, if the remaining strength of a wood pole is less than 60%, the final HI for that asset is halved.

In general, most distribution utilities employ an additive model with select gateway model elements. METSCO selected this approach when conducting the ACA, which is in alignment with most of PUC's peer utilities.

3.4 Overview of Selected Methodology

3.4.1 Condition Parameters

To calculate the HI for an asset, formulations are developed based on condition parameters that can be expected to contribute to the degradation and eventual failure of that asset. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 3-1**Error! Reference source not found.** exemplifies a HI formulation table.

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific and uniquely graded to each asset class. Additionally, some condition parameters can be comprised of sub-condition parameters. For example, the oil quality condition parameter for a station power transformer is based on multiple sub-condition parameters such as the acidity of the oil, its interfacial tension, dielectric strength, and water content.

Figure 3-1: HI Formulation Components

Degradation Factor:
The asset aging mechanisms, tests, or failure modes.

Condition Indicator Numerical Score:
The converted numerical score associated with the degradation factor, which corresponds directly with the indicator letter score.

Condition Max Score:
The highest obtainable Score for each degradation factor. (4 x Weight)

#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Condition Weight:
The impact of the condition with respect to asset failure and/or the safe operation of the asset. Higher impact results in higher weight

Condition Indicator Letter Score:
The letter grade associated with the degradation factor – this is typically captured from the raw inspection data.

Asset Max Score:
The highest numerical grade that can be assigned to the asset / asset class, given the associated degradation factors and weights.

The scale used to determine an asset's score for a condition parameter is called the "condition indicator". Each condition parameter is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a condition score of 4 represents the best grade, whereas a condition score of 0 represents the worst grade.

A – 4 Best Condition

B – 3 Normal Wear

C – 2 Requires Remediation

D – 1 Rapidly Deteriorating

E – 0 Beyond Repair

3.4.2 Use of Age as a Condition Parameter

Some industry participants question the appropriateness of including age as a potential condition parameter for calculating asset HI values. At the core of the argument against the use of age in calculating asset condition is the notion that age implies a linear degradation path for an asset that does not always match the actual experience in the field.

While some assets lose their structural integrity faster than would be expected with the passage of time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer period than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, METSCO limits the instances where it relies on only age as a parameter explicitly incorporated into the HI formulation. In some cases, however, the limited number of condition parameters available for calculation of asset health makes age a useful proxy for the important factors that the analysis would not otherwise capture. In other cases, such as when assessing condition of complex equipment containing several internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing, age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

3.4.3 Final Health Index Formulation

The final HI, which is a function of the condition scores and weightings, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} Weight_i * Numerical\ Grade_i}{Total\ Score} \right) x\ 100\%$$

Where *i* corresponds to the condition parameter number, and the HI is a percentage representing the remaining life of the asset.

A gating approach is used for condition parameters that have a significant influence on the health of an asset. If the condition parameter that has been flagged as a gating parameter is below a pre-defined threshold value, the overall HI is reduced by 50%. This approach enables utilities to efficiently flag severely degraded assets through identification of condition parameters acknowledged to be critical indicators of overall asset health.

3.4.4 Health Index Results

METSCO's assessment of asset condition uses a consistent five-point scale along the expected degradation path for every asset, ranging from Very Good to Very Poor. To assign each asset into one of the categories, METSCO constructs an HI formulation for each asset class, which captures information on individual degradation factors contributing to that asset's declining condition over time. Condition scores assigned to each degradation factor are also expressed as numerical or letter grades along with pre-defined scales. The final HI – expressed as a value between 0% and 100% - is a weighted sum of scores of individual degradation factors, with each of the five condition categories (Very Good, Good, Fair, Poor, Very Poor) corresponding to a numerical band. For example, the condition score of Very Good indicates assets with HI values between 100% and 85%, whereas assets found to be in a Very Poor condition score are those with calculated HI values between 0% and 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 3-1 presents the HI ranges with the corresponding asset condition, its description as well as implications for maintaining, refurbishing or replacing the asset prior to failure.

Table 3-1: HI Ranges and Corresponding Asset Condition

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components	Normal Maintenance
[70-85]	Good	Significant Deterioration of some components	Normal Maintenance
[50-70]	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50]	Poor	Widespread serious deterioration	Start the planning process to replace or rehabilitate, considering the risk and consequences of failure
[0-30]	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on assessment

3.5 Data Availability Index

To put the calculation of HI values into the context of available data, METSCO supplemented its HI findings with the calculation of the DAI: a measure of the availability of the condition parameter data for a specific asset weighted by each condition parameter to the HI score. The DAI is calculated by dividing the sum of the weights of the condition parameters available to the total weight of the condition parameters used in the HI formulation for the asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} Weight_i * \alpha_i}{\sum_{i=1} Weight_i}\right) x\ 100\%$$

Where i corresponds to the condition parameter number and α is the availability of coefficient (=1 when data available =0 when data unavailable)

An asset with all condition parameter data available will have a DAI value of 100%, independent of the asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. For distribution assets – typified by relatively large asset populations – if the DAI for an asset is less than 70%, a valid HI cannot be calculated. The subset of distribution assets without a valid HI are assigned an extrapolated HI value using the valid HI results for assets within the same asset class and ten-year age band. Similarly for station assets – typified by relatively small asset populations – if the DAI for an asset is less than 65%, a valid HI cannot be calculated. HI results for station assets are not extrapolated due to the small population.

4 Health Index Formulations and Results

This section presents the developed HI formulation for each asset class, the calculated scores for HI results, and the data available to perform the study.

4.1 Distribution Assets

4.1.1 Wood Poles

Wood poles are an integral part of any distribution system. They are the support structures for overhead distribution system. The HI for wood poles is calculated by considering a combination of end-of-life criteria summarized in Table 4-1.

Table 4-1: Wood Pole HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Remaining Strength	8	A,B,C,D,E	4,3,2,1,0	32
Pole Treatment Type	3	A,C,E	4,2,0	12
Mechanical Condition	4	A,B,C,D,E	4,3,2,1,0	16
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**76**

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation process for wood poles involves biological and environmental mechanisms such as fungal decay, wildlife damage, and weather effects which can impact the mechanical strength of the pole. Any loss in the strength of the pole can present additional safety and environmental risks to the public and to PUC. The remaining strength condition parameter is a quantitative measurement that provides adequate evidence of the deterioration of the operational health of the asset.

The HI formulation for wood poles is a combination between the additive and gateway model; with the gateway applied to the remaining strength parameter. When the remaining strength for a pole is below 60%, the final HI for that pole is reduced by half. CSA standard C22.3 no. 1 requires that any pole with a remaining strength less than 60% of its design strength be replace or reinforced[3]. PUC only tests poles that are ten years old or more; therefore, once a pole reaches ten years of age it is scheduled for testing on the seven-year

[3] *Overhead Systems*, CAN/CSA C22.3 No.1-15, 2015

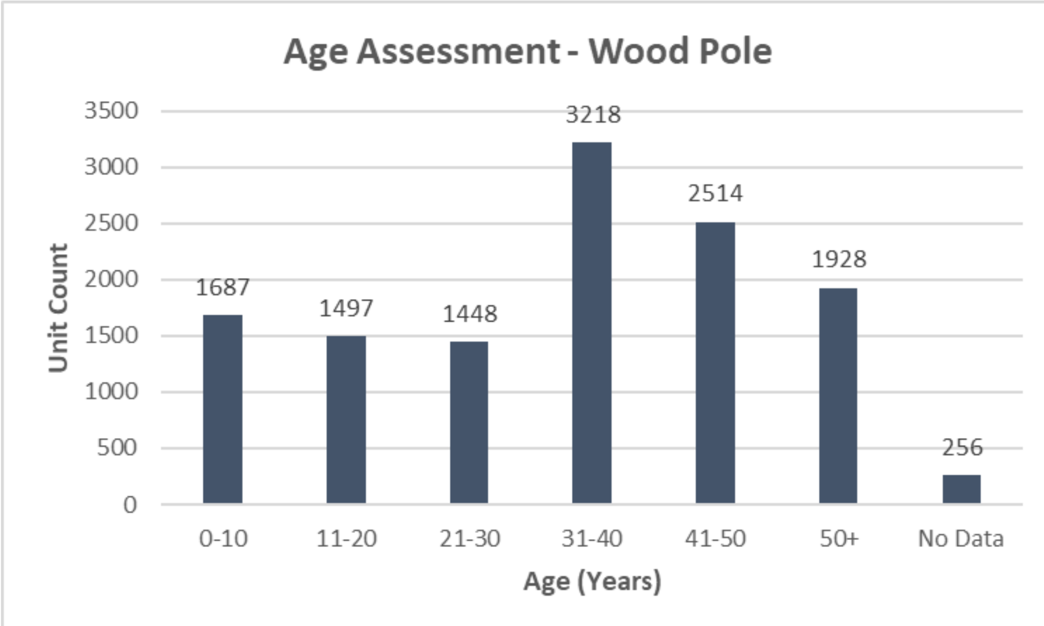
test cycle. To account for this in the ACA, poles which are fifteen years old or less are not treated as requiring a Remaining Strength value.

Additional condition parameters include service age, mechanical condition, and the pole treatment type. The mechanical condition of a pole is comprised of many factors, which are:

- Pole-top feathering
- Wood pole hole
- Surface rot below ground line
- Internal decay
- Ground line
- Crossarm rot
- Decay pockets at ground line
- Surface rot above ground line
- Mechanical damage
- Cracks
- Fire damage
- Carpenter ants damage

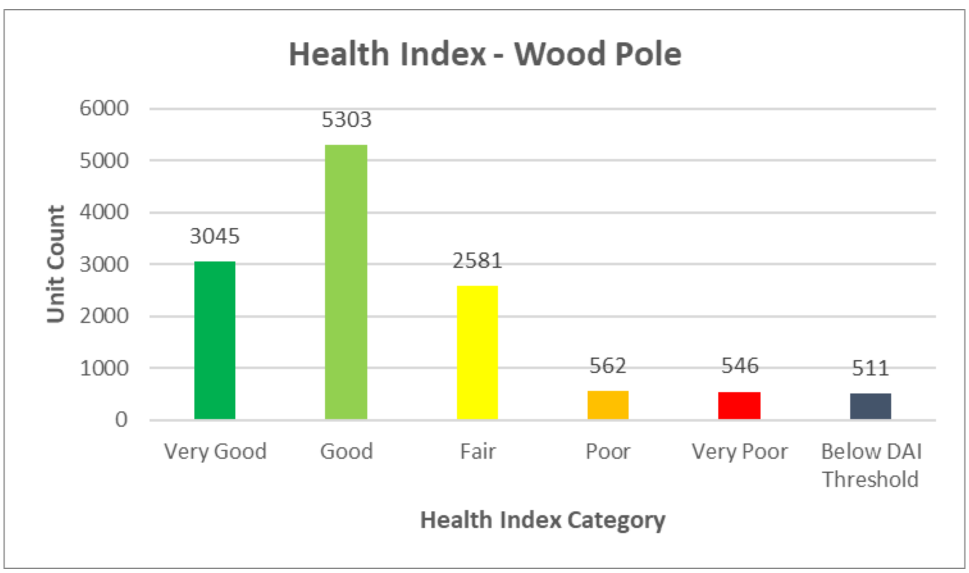
PUC owns approximately 12,600 wood poles within its service territory. Installation date is known for nearly 98% of the total in-service population. Figure 4-1 presents the age distribution for in-service wood poles.

Figure 4-1: Wood Poles Age Demographics



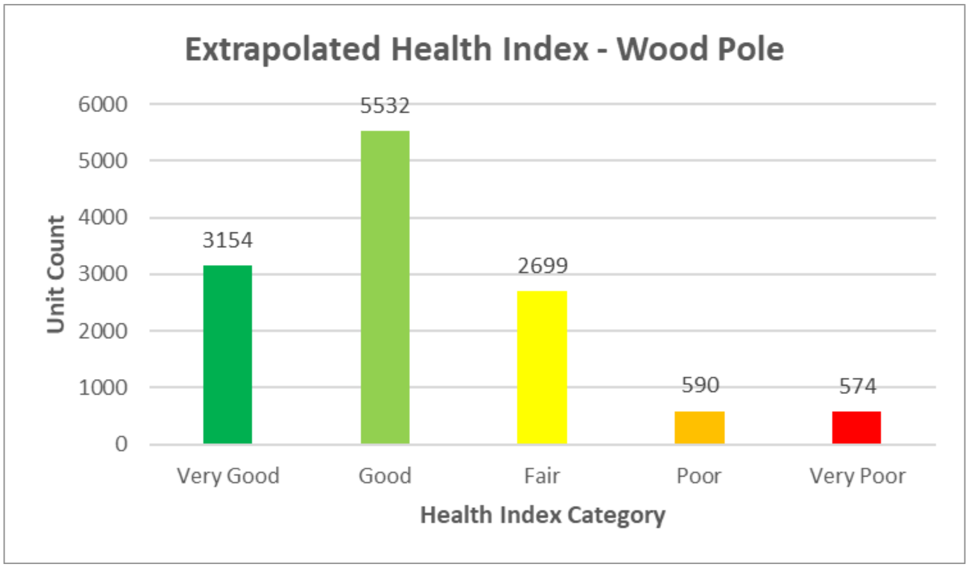
PUC's pole maintenance and nameplate data were used to calculate the HI based on the criteria provided Table 4-1. As shown in Figure 4-2, a valid HI was calculated for 96% of the wood poles.

Figure 4-2: Wood Pole HI Results



To complete the full analysis, the HI for the remaining 4% of poles has been extrapolated based on the HI distribution with a valid HI score within each ten-year age group. The overall extrapolated HI distribution for wood poles is presented in Figure 4-3.Most of the poles are in Very Good or Good condition with less than 12% of the total population being in Poor or Very Poor condition.

Figure 4-3: Extrapolated Wood Pole HI Results

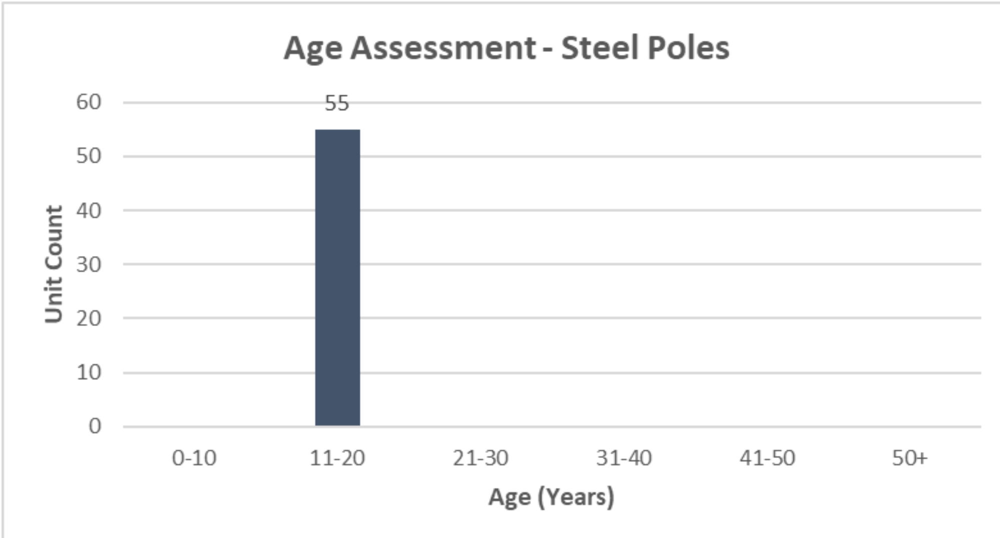


4.1.2 Steel Poles

Like wood poles, steel poles support the overhead distribution system. Steel is a conductive material and is not a typical pole type used by electric utilities; hence, PUC has a small number of steel poles on their distribution system. Due to the unavailability of inspection data for steel poles, health indices were not calculated.

PUC owns 55 steel poles within its service territory. The installation date is known for all steel poles, as shown in Figure 4-4.

Figure 4-4: Steel Pole Age Demographics



4.1.3 Overhead Primary Conductors

Overhead distribution conductors transmit electricity from generators to TS, from TS to substations, and from substations to customer premises and are supported by poles. Although laboratory tests are available to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for the tensile strength of the conductor and to determine the remaining life of the asset is the use of service age.

PUC owns 615 km of overhead distribution primary conductor with its service area. PUC's overhead distribution conductors operate at various voltage levels; 4.16kV, 12.47kV, 34.5kV and 115kV. Voltage level demographics are presented below in Figure 4-5. An age assessment was evaluated for the overhead conductor population, Figure 4-6 to Figure 4-8 below represent the overhead lines age distribution.

Figure 4-5: Overhead Lines Voltage Demographics

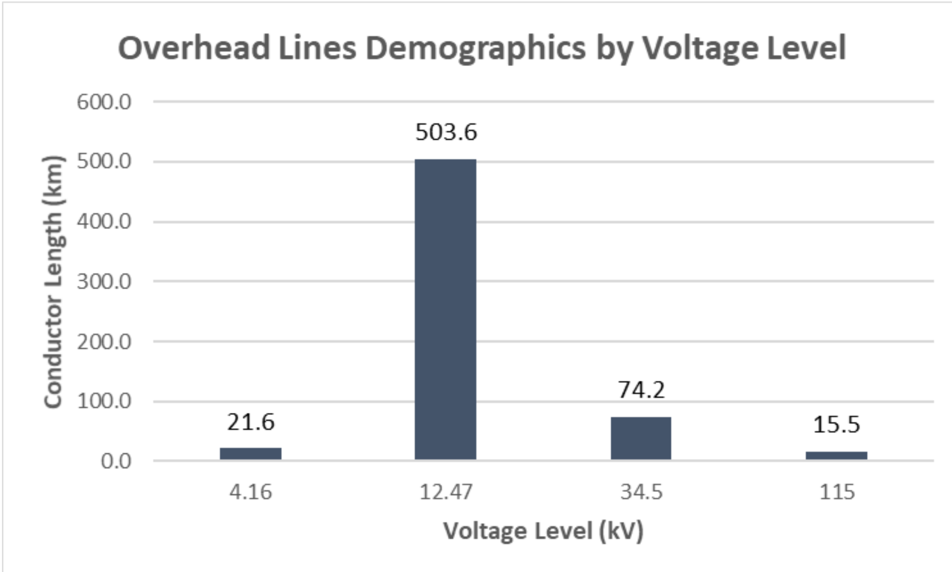


Figure 4-6: 1-Phase Overhead Line Age Demographics

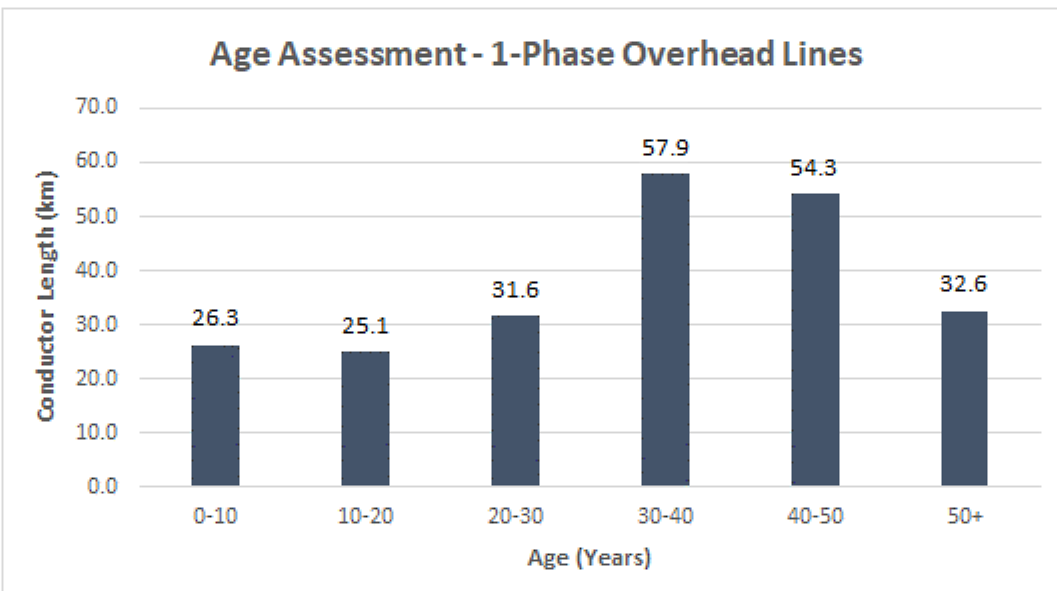


Figure 4-7: 2-Phase Overhead Lines Age Demographics

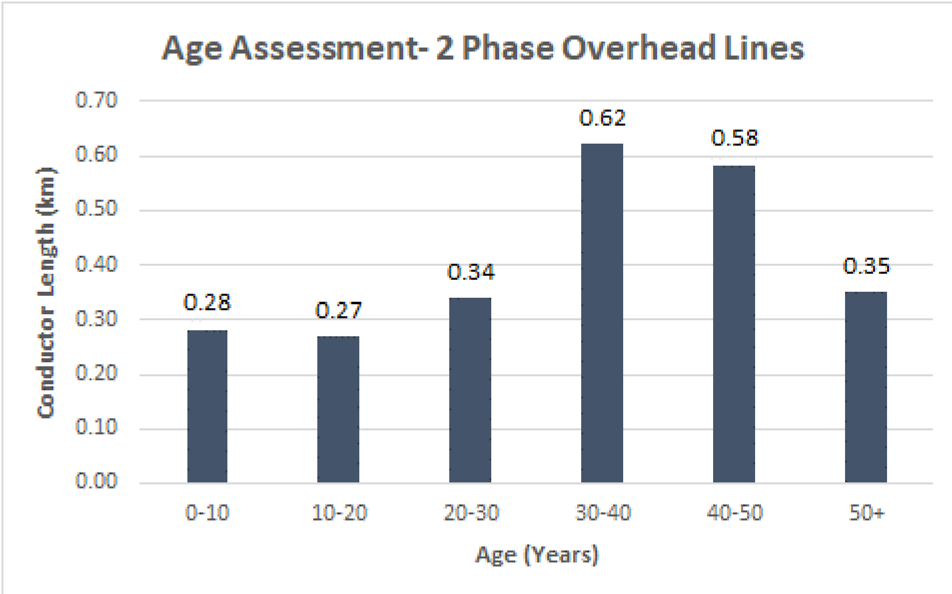
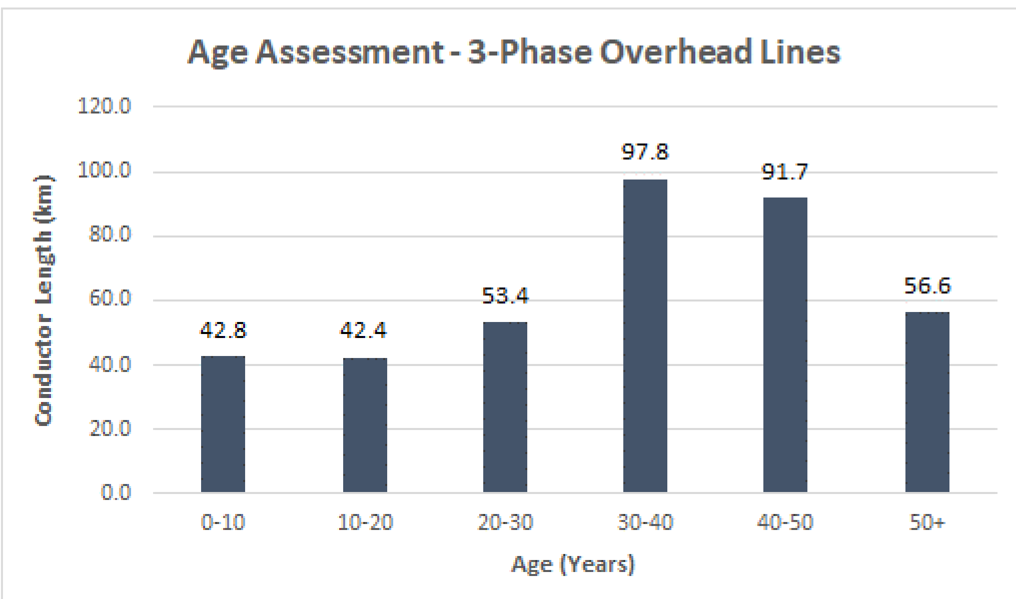


Figure 4-8: 3-Phase Overhead Line Age Demographics



4.1.4 Underground Primary Cables

Like overhead conductors, underground cables also transmit electricity along the electrical distribution system; however, they are located below ground. PUC's underground system consists of cross-linked polyethylene ("XLPE") cables for the most part, but also includes a mix of other insulation types including tree-retardant XLPE ("TR-XLPE"), butyl rubber, and an older General Electric cross-linked polymer dielectric known as "Vulkene".

Compared to overhead lines, cables can be more reliable since they are not exposed to severe weather conditions, tree contacts, or foreign interference. However, distribution underground cables use solid insulation (rather than air as used by the overhead system); thus, any cable fault is permanent until spliced out. Managing a cable system is more expensive and these are some of the more challenging assets in electricity systems from a condition assessment and AM viewpoint.

Several test techniques such as partial discharge ("PD") and water tree diagnostic testing have become available over recent years to identify the condition and performance of the asset class. Some tests can be destructive to the asset and hence are used less frequently. Accordingly, the preference is given to non-destructive testing. In the absence of test results, cable age can be used as a proxy for medium-term and long-term planning to predict quantities of cables that are expected to reach end-of-life.

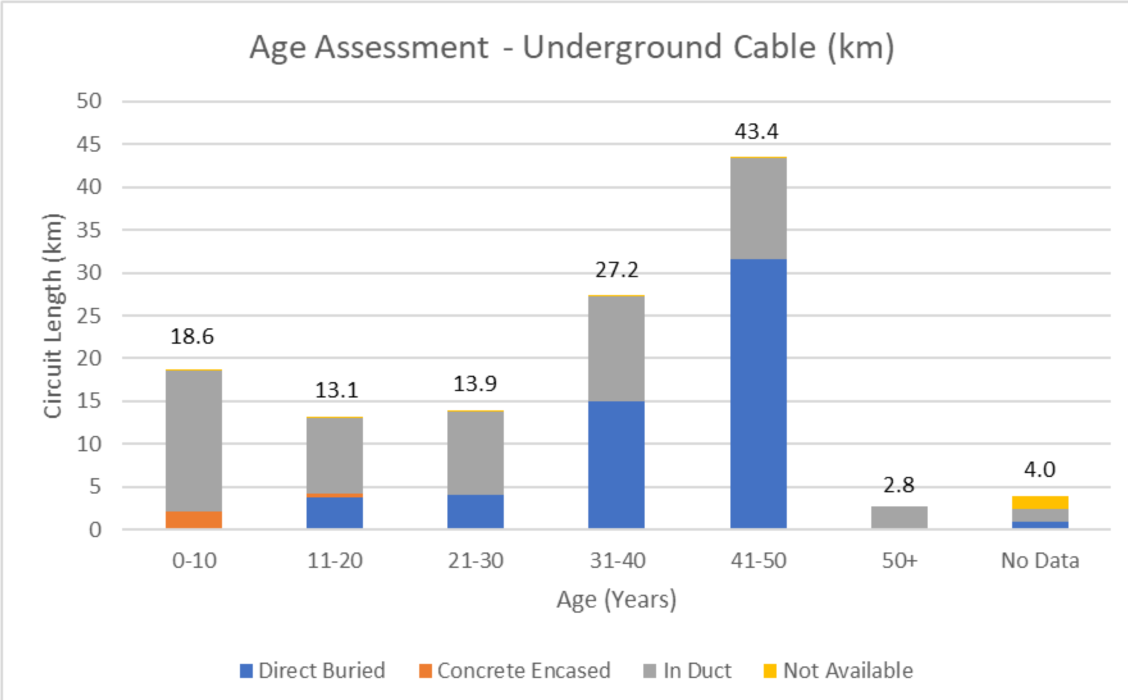
Due to the absence of test results, the health index formulation of underground cables only involved using the service age of the cable as well as the circuit's historical failures during the last five years. Table 4-2 presents the HI formulation of underground cables.

Table 4-2: Underground Cable HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	5	A,B,C,D,E	4,3,2,1,0	20
Circuit Failure Records	2	A,B,C,D,E	4,3,2,1,0	8
			Total Score	**28**

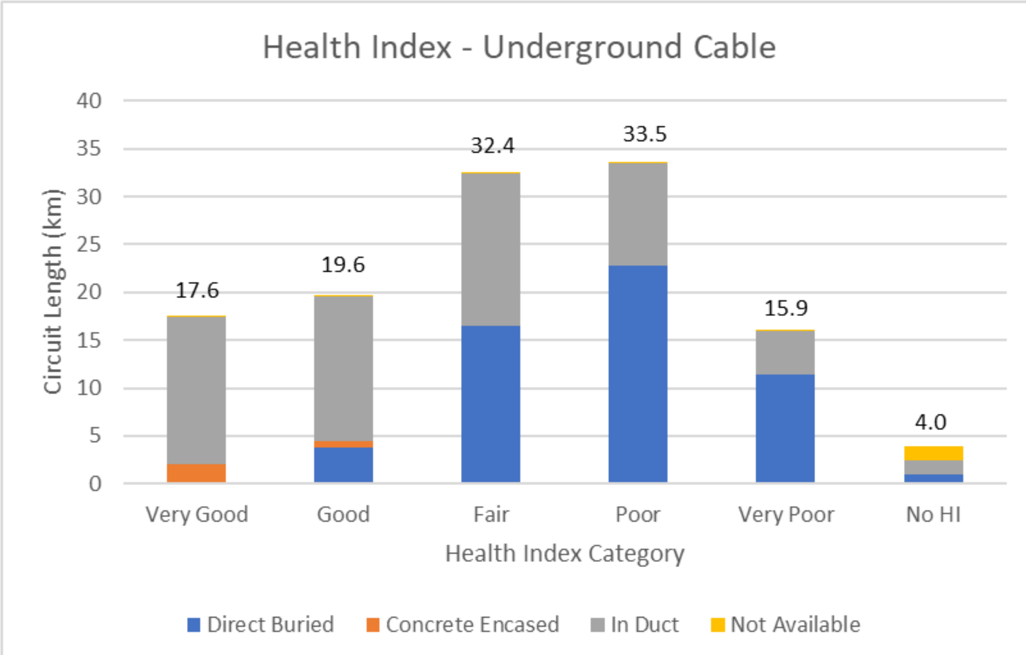
PUC owns approximately 123 km of underground primary cable within its service territory. Installation dates are known for nearly 97% of underground cable length. Figure 4-9 Figure 4-9 presents the total length of underground primary cables by the cables' buried status.

Figure 4-9: Overall Underground Primary Cable Age Demographics



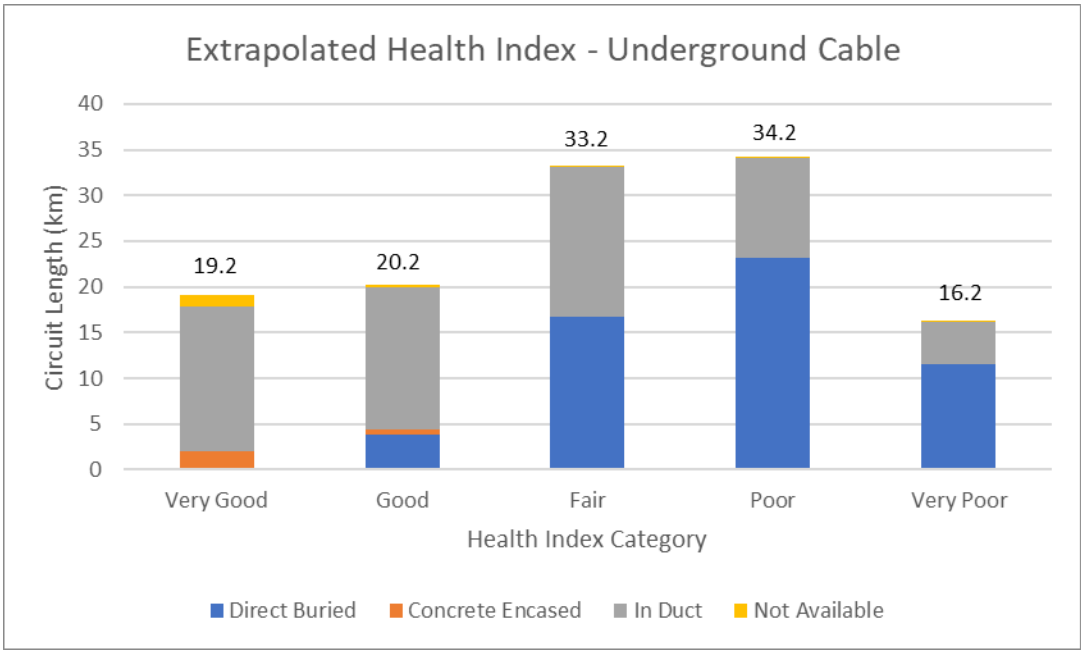
PUC's underground primary cable maintenance and nameplate data were used to calculate the HI based on the criteria provided in Table 4-2. As shown in Figure 4-10, a valid HI was calculated for 97% of underground cables.

Figure 4-10: Underground Cable HI Results



To complete the full analysis, the HI for the remaining 3% of cables has been extrapolated based on the HI distribution with a valid HI score within each ten-year age group. The overall extrapolated HI distribution for underground cables is presented in Figure 4-11. Approximately, 40% of the population is in Good or Very Good condition while the remaining 60% lie in “Fair” condition or worse.

Figure 4-11: Extrapolated Underground Cable HI Results



4.1.5 Pole-mount Transformers

Pole-mount transformers are installed on service poles above ground with the primary function to step down power from the medium-voltage distribution system to the voltage rating for customer use. The HI for pole-mount transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-3.

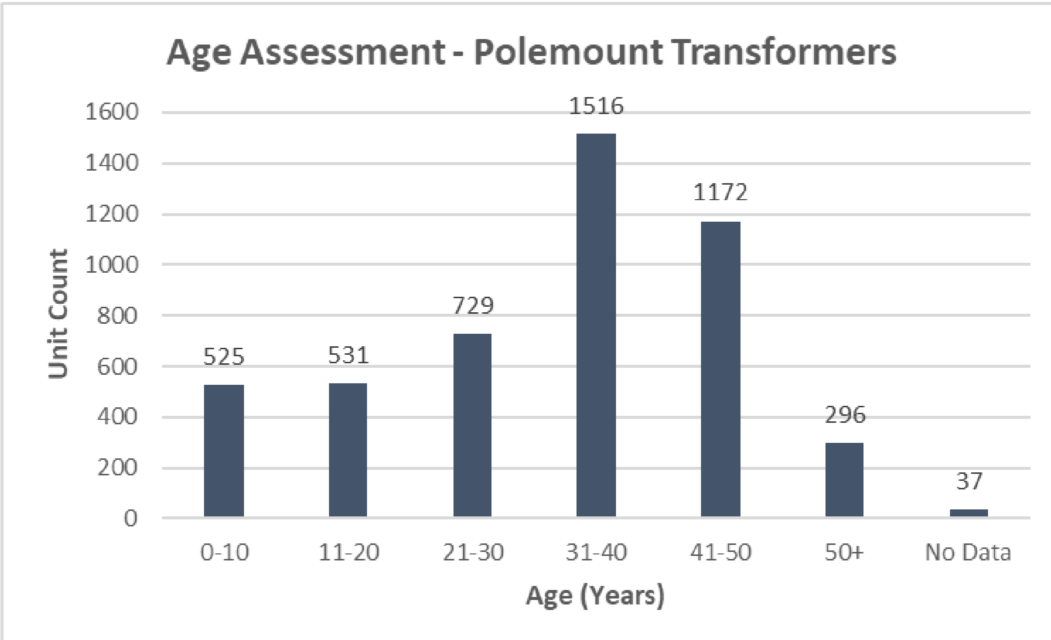
Table 4-3: Pole-mount Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Peak Loading	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**24**

In addition to service age, peak loading is used as a condition parameter. Load unbalances or peak loading can reduce the useful life of a distribution transformer.

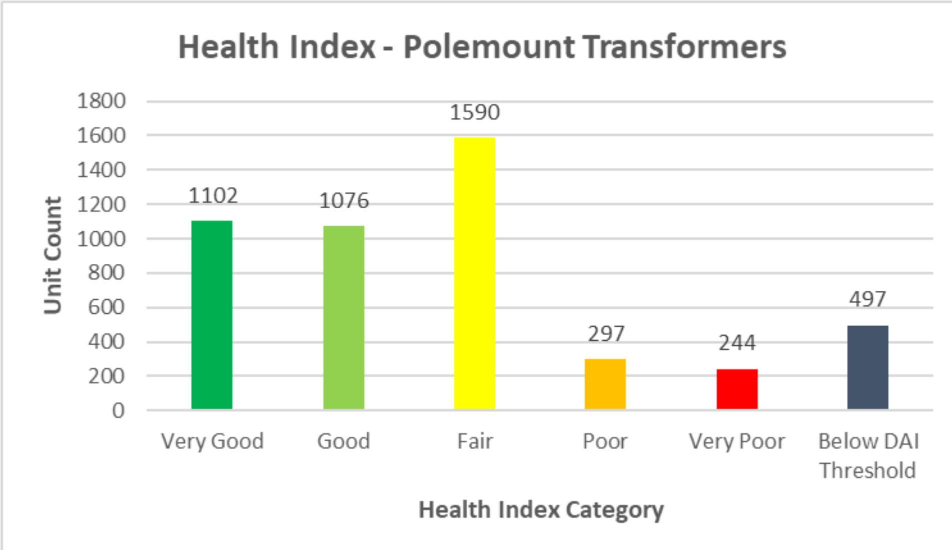
PUC owns 4,806 pole mount transformers within its service territory. Installation dates are known for 99% of the total in-service population. Figure 4-12 presents the age distribution for pole-mount transformers.

Figure 4-12: Pole-Mount Transformer Age Demographics



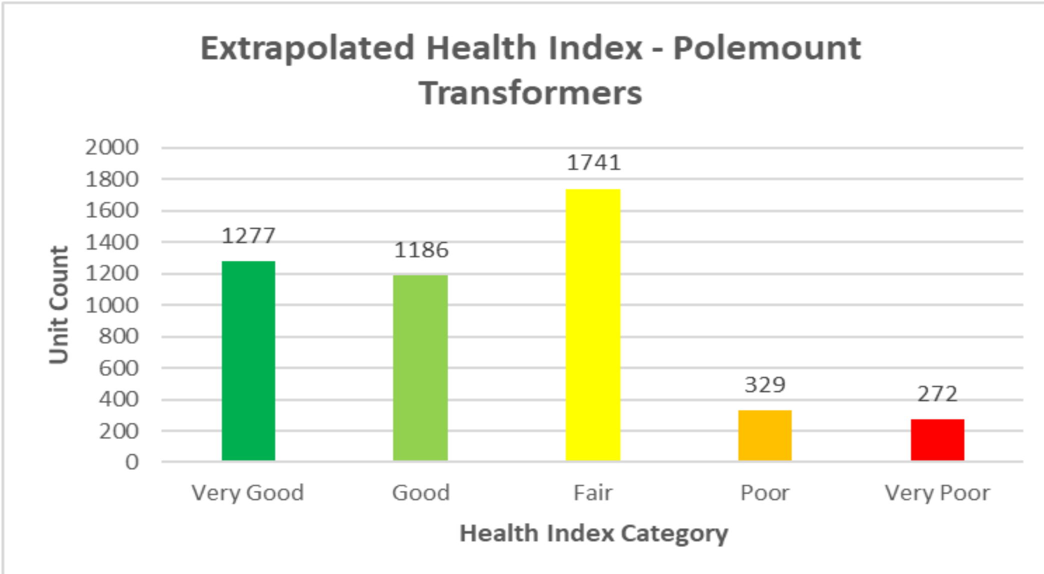
PUC's nameplate information and operating loading data were used to calculate the HI based on the criteria listed in Table 4-3. A valid HI was calculated for 90% of the overhead transformers. The HI results can be seen in Figure 4-13.

Figure 4-13: Pole-Mount Transformer HI Results



To complete the full analysis, the HI results for the remaining 10% of pole-mount transformers were extrapolated based on the HI distribution of the asset population with a valid HI score. The overall HI distribution for pole-mount transformers is presented in Figure 4-14. Nearly half of the population is in Very Good or Good condition, while over a third are in Fair condition.

Figure 4-14: Extrapolated Pole-Mount Transformer HI Results



4.1.6 Pad-mount Distribution Transformers

Pad-mount distribution transformers are utilized for similar functionalities as pole-mount transformers. They step down power from the medium-voltage distribution system to the final utilization voltage for the customer; however, they are placed on the ground level.

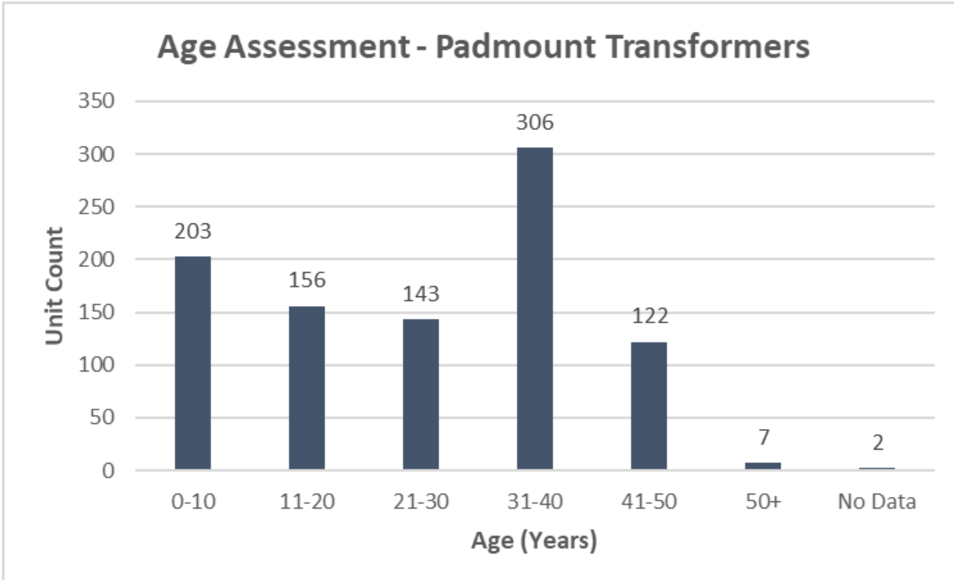
The HI for underground distribution transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-4.

Table 4-4: Pad-mount Distribution Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Peak loading	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**24**

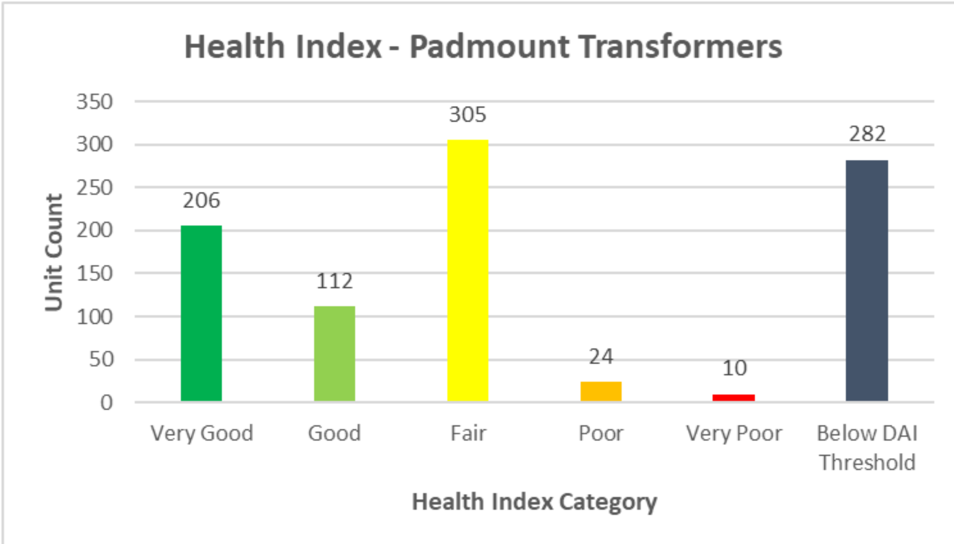
PUC owns 939 pad-mount transformers within its service territory. The installation dates are known for nearly the entire population. Figure 4-15 presents the age distribution for pad-mount transformers.

Figure 4-15: Pad-mount Transformer Age Demographics



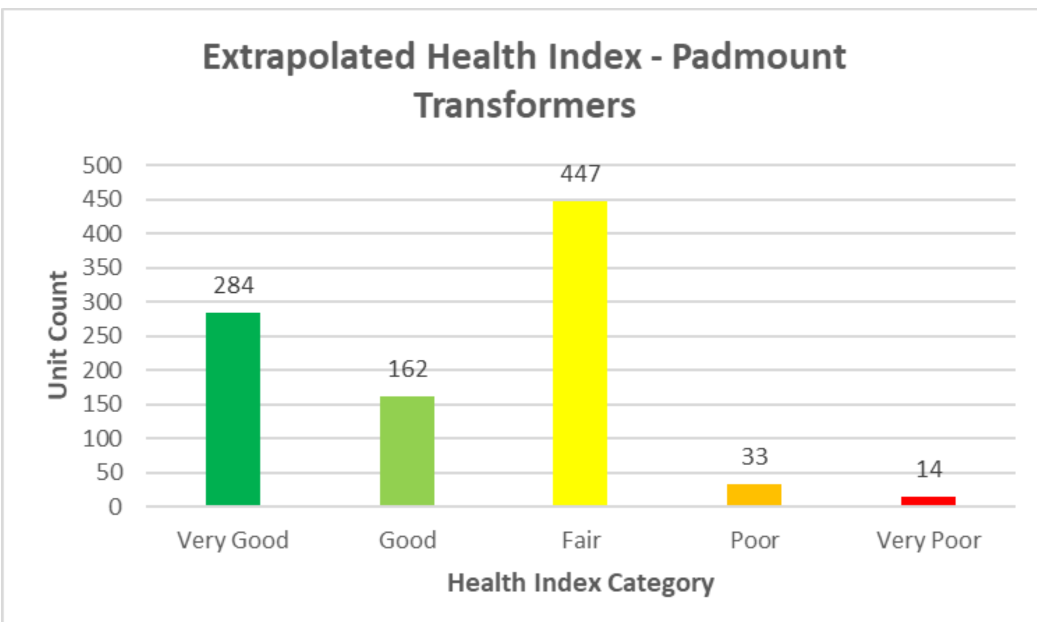
PUC's nameplate information and operational loading data were used to calculate the HI results based on the criteria provided in Table 4-4. Nearly 1.5% of the pad-mount transformers within PUC's service territory have peak loading percentage greater than 100% which can pose operating restrictions and impact the condition of the assets. The HI distribution is presented in Figure 4-16. A valid HI was calculated for 70% of pad-mount transformers.

Figure 4-16: Pad-mount Transformer HI Results



To complete the full analysis, the HI for the remaining population was extrapolated based on the HI distribution of the asset population with a valid HI score. As illustrated in Figure 4-17, most of the population is either in a Fair condition or better.

Figure 4-17: Extrapolated Pad-mount Transformer HI Results



4.1.7 Submersible Transformers

Submersible distribution transformers are utilized for similar functionalities as pole-mount and pad-mount transformers. They step down power from the medium-voltage distribution system to the final utilization voltage for the customer; however, they are placed below the ground level in a vault.

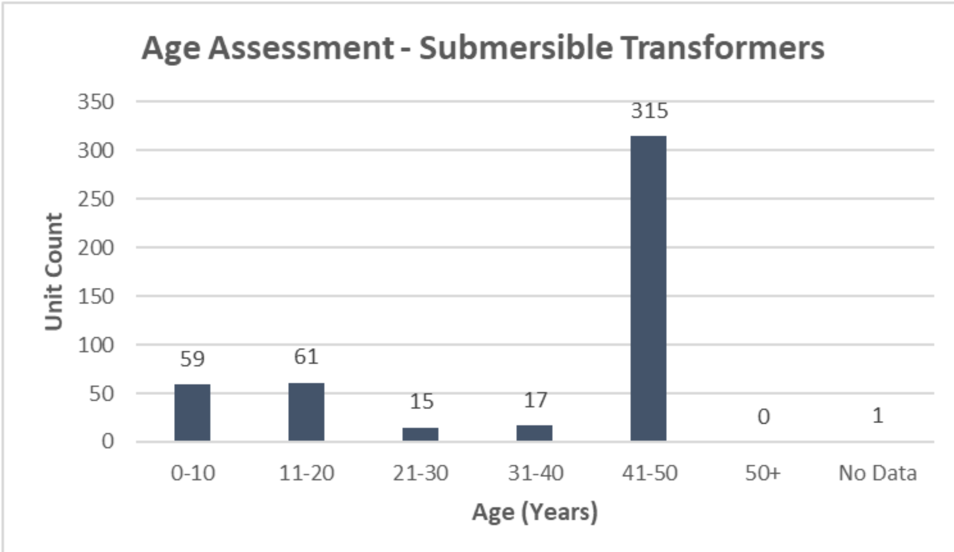
The HI for submersible transformers is calculated by considering a combination of end-of-life criteria summarized in Table 4-5. Several of PUC's vaults use tar paper, which is a flammable substance. Due to the higher probability of catastrophic failure, a condition parameter for whether the vault is made of tar paper is added.

Table 4-5: Submersible Distribution Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
End Grate Condition	1	A,B,C,D,E	4,3,2,1,0	4
Lid Condition	4	A,B,C,D,E	4,3,2,1,0	16
Corrosion on Tank	4	A,B,C,D,E	4,3,2,1,0	16
Debris	1	A,B,C,D,E	4,3,2,1,0	4
Terminations	2	A,B,C,D,E	4,3,2,1,0	8
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
Ground Straps	2	A,E	4,0	8
Tar Paper Vault	6	A,E	4,0	24
			Total Score	**96**

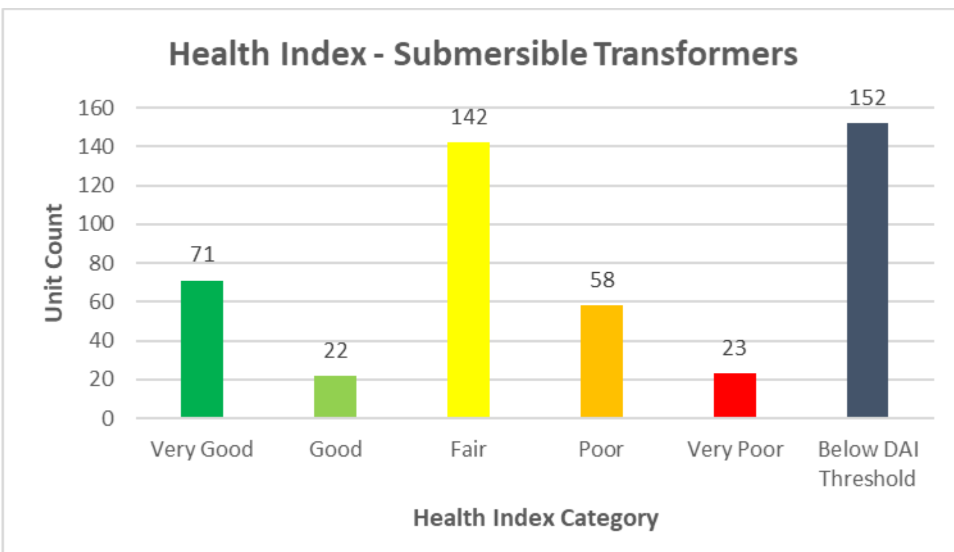
PUC owns 468 submersible transformers within its service territory. The installation dates are known for nearly the entire population. Figure 4-18 presents the age distribution for submersible transformers.

Figure 4-18: Submersible Transformers Age Demographics



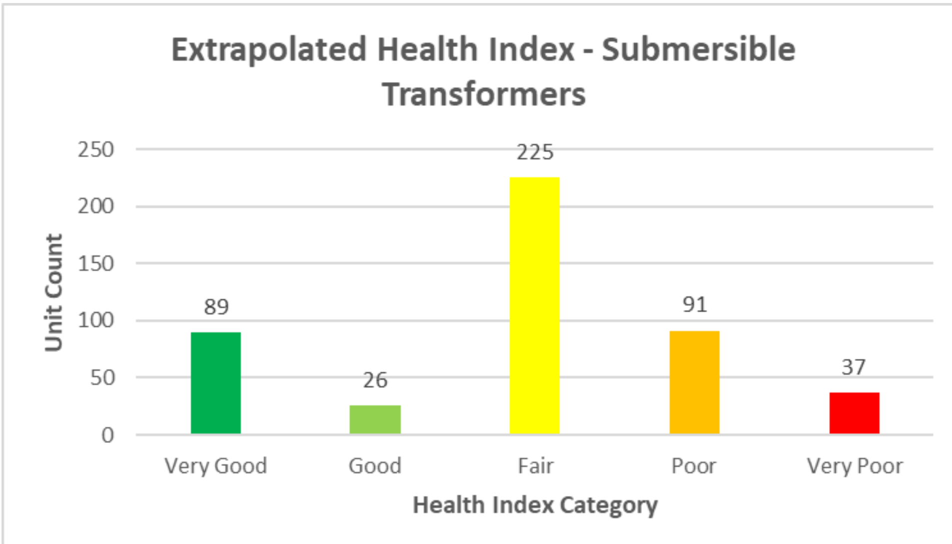
PUC's inspection data were used to calculate the HI results based on the criteria provided in Table 4-5. The HI distribution is presented in Figure 4-19. A valid HI was calculated for 68% of the population.

Figure 4-19: Submersible Transformer HI Results



To complete the full analysis, the HI for the remaining population was extrapolated based on the HI distribution of the asset population with a valid HI score. As illustrated in Figure 4-20, over 70% of the population is either in a Fair condition or better.

Figure 4-20: Extrapolated Submersible Transformer HI Results



4.1.8 Underground Switches

PUC's underground switches are junction boxes manufactured by Kbar that can be operated if needed. The HI for underground switches is calculated by considering a combination of end-of-life criteria summarized in Table 4-6.

Table 4-6: Underground Switch HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Visual Inspections	1	A,B,C,D,E	5,4,3,2,1	5
			Total Score	**5**

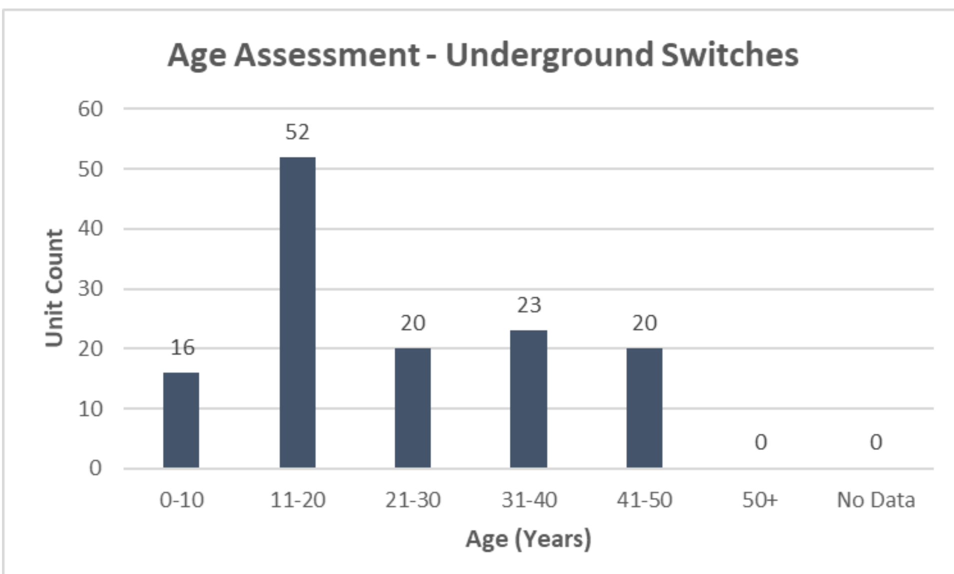
The visual inspections comprise of multiple inspection parameters:

- Paint condition
- Pad
- Sealed
- Doors, locks, and latches
- Water ingress

- Conduits
- Condensation
- Contamination
- Grounding
- Physical condition
- Electrical clearances
- Terminations
- Installations
- Insulator condition
- Switch contacts
- Fuses
- Fuse Holders

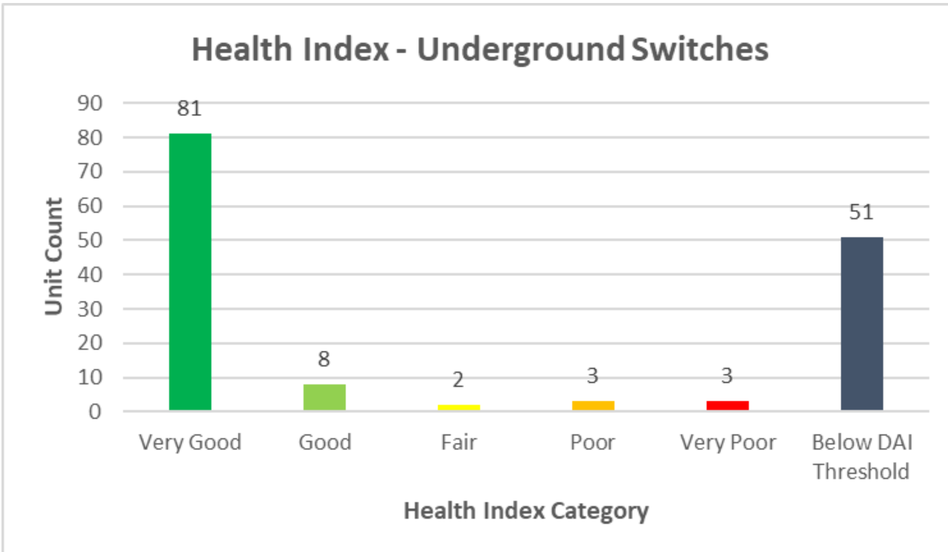
PUC owns 148 underground switches within its service territory. The installations dates are known for the entire underground switch population. Figure 4-21 presents the age distribution for underground switches to show an approximate representation of the age distribution.

Figure 4-21: Underground Switch Age Demographics



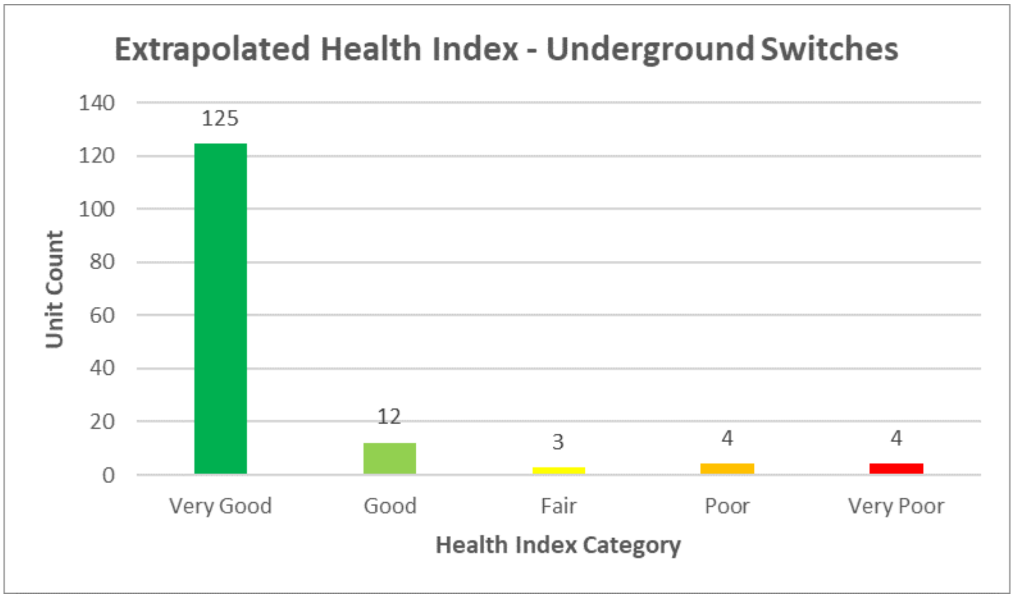
PUC's maintenance records and nameplate information were used to calculate the HI results based on the criteria provided in Table 4-6. A valid HI was calculated for 66% of the underground switches, as shown in Figure 4-22.

Figure 4-22: Underground Switch HI Results



To complete the full analysis, the HI for the remaining population was extrapolated based on the HI distribution of the asset population with a valid HI score. As shown in Figure 4-23, most of the switches are in Very Good or Good condition, with less than 8% of the switches in Fair condition or worse.

Figure 4-23: Extrapolated Underground Switch HI Results



4.1.9 Distribution Switchgear

Distribution switchgears provide the required level of operating flexibility for the underground system. They are employed for controlling, regulating, and isolating the electrical circuit in the underground distribution system. During a fault, switchgear can be used to isolate and the faulted section and restore power to unfaulted parts of the system. Switchgear can also de-energize equipment during maintenance and testing. In some cases, they are used to transfer power manually or automatically in distribution circuits from a preferred source to an alternate source. The HI for distribution switchgears is calculated by considering a combination of end-of-life criteria summarized in Table 4-7.

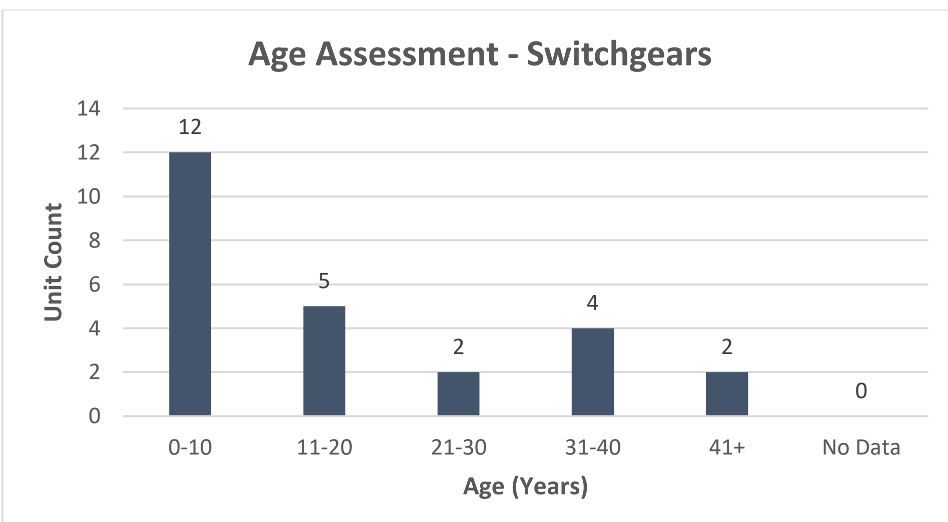
Table 4-7: Switchgear HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	4	A,B,C,D,E	4,3,2,1,0	16
Pad condition	4	A,B,C,D,E	4,3,2,1,0	16
IR Scan	1	A,B,C,D,E	4,3,2,1,0	4
Barrier boards	3	A,B,C,D,E	4,3,2,1,0	12
Terminations	2	A,B,C,D,E	4,3,2,1,0	8
Enclosure (excluding pad)	3	A,B,C,D,E	4,3,2,1,0	12
Internal components	4	A,B,C,D,E	4,3,2,1,0	16
Insulators	2	A,B,C,D,E	4,3,2,1,0	8
Switch mechanism	2	A,B,C,D,E	4,3,2,1,0	8
			Total Score	**100**

IR scan results represent an important condition parameter for condition assessment of distribution switchgear since they identify hotspots (i.e. high temperatures) on the asset. Assets operating continuously at high temperatures can cause accelerated degradation of the asset and may experience premature failure. It is assumed and confirmed by PUC that switchgear exhibiting high temperatures have since been corrected.

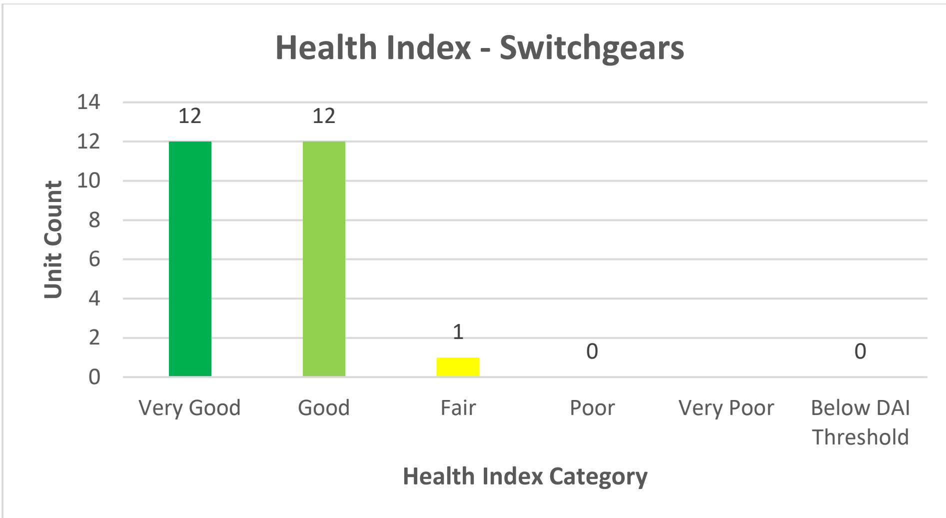
PUC owns 25 switchgear units within its service territory. Figure 4-24 presents the age distribution for PUC's switchgear.

Figure 4-24: Switchgear Age Demographics



The overall switchgear HI distribution is presented in Figure 4-25. All the switchgears are in Good or Very Good condition other than one in Fair condition.

Figure 4-25: Switchgear HI Results

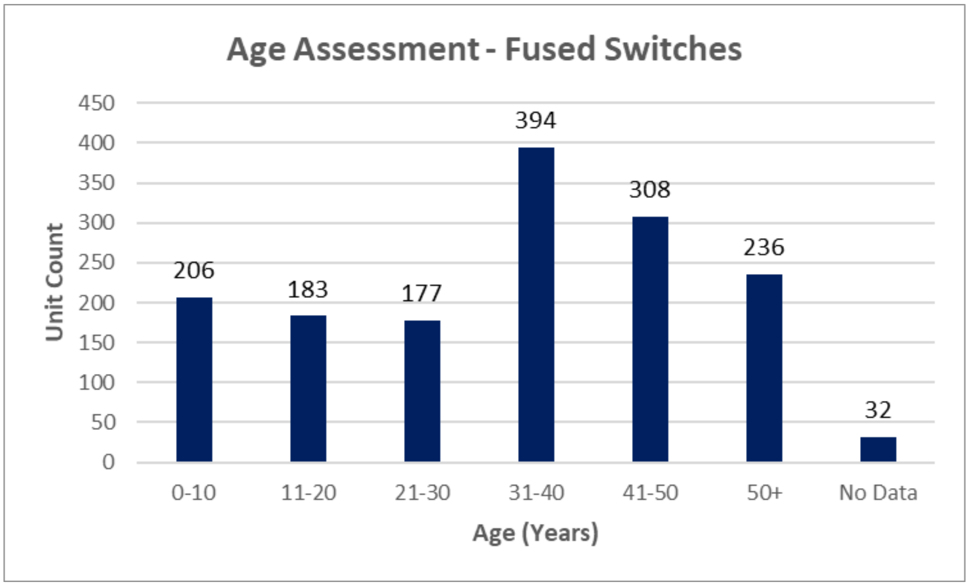


4.1.10 Fused Switches (Cut-outs)

Fused switches (also called cut-outs) provide over-current protection during overload conditions or short circuits. Some fused switches are also designed to provide load-breaking capabilities via the fuse holder.

PUC owns a total of 1536 fused switches within its service territory. Fused switches are assumed to have the same age distribution as wood poles. The TUL for this asset class is 45 years. The age demographic indicates this is an aging asset population – given that 27% of the population is currently past its TUL and 10% will reach TUL in the next 5 years. Figure 4-26 presents the age distribution for fused switches.

Figure 4-26: Fused Switches Age Demographics

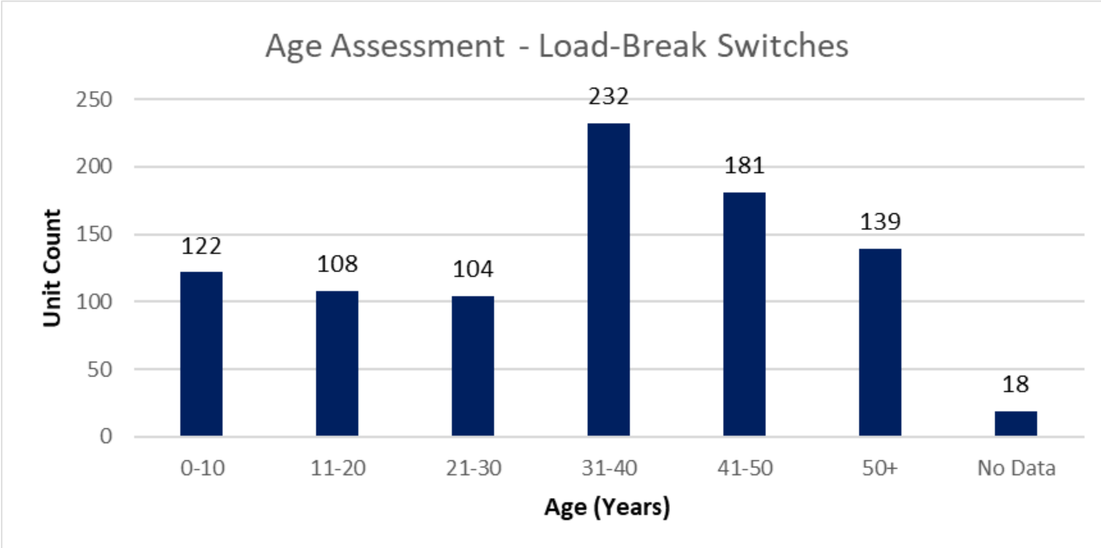


4.1.11 Load-Break Switches

Load-break switches are solid-blade devices used to make or break load during planned and unplanned switching operations. These switches can be installed as single-phase, in-line devices or three-phase group-operated devices.

PUC owns a total of 905 load-break switches within its service territory. Load-break switches are assumed to have the same age distribution as wood poles. The TUL for this asset class is 45 years. The age demographic indicates this is an aging asset population – given that 27% of the population is currently past its TUL and 10% will reach TUL in the next 5 years. Figure 4-27 presents the age distribution for load-break switches.

Figure 4-27: Load-Break Switches Age Demographics



4.2 Station Assets

4.2.1 Power Transformers

Power transformers are key stations assets owned by PUC that are used to step down the voltage from the transmission to sub-transmission systems, or from the sub-transmission system to distribution levels. Computing the HI for a power transformer requires the combination of various end-of-life criteria for its components. Table 4-8 summarizes the HI formulation used for power transformers.

Table 4-8: Power Transformer HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Dissolved Gas Analysis	6	A,B,C,D,E	4,3,2,1,0	24
Service Age	10	A,B,C,D,E	4,3,2,1,0	40
Oil Quality	4	A,B,C,D,E	4,3,2,1,0	16
Furan Analysis	3	A,B,C,D,E	4,3,2,1,0	12
Load History	5	A,B,C,D,E	4,3,2,1,0	20
Average Winding Temperature	1	A,B,C,D,E	4,3,2,1,0	4
Transformer Main Tank/ Cabinet and Control Condition	3	A,B,C,D,E	4,3,2,1,0	12
Oil Leaks	3	A,B,C,D,E	4,3,2,1,0	12
Gauges, Gas Pressure Relief and Gas Pressure Relay Condition	1	A,B,C,D,E	4,3,2,1,0	4
Transformer Conservator/ Oil Preservation System Condition	2	A,B,C,D,E	4,3,2,1,0	8
Radiators/ Cooling system	2	A,B,C,D,E	4,3,2,1,0	8
Connectors	1	A,B,C,D,E	4,3,2,1,0	4
Transformer Foundation/ Support Steel	1	A,B,C,D,E	4,3,2,1,0	4
Grounding Condition	1	A,B,C,D,E	4,3,2,1,0	4
Bushing head Condition	3	A,B,C,D,E	4,3,2,1,0	12
Bushing Condition	3	A,B,C,D,E	4,3,2,1,0	12
Tap Changer Tank Condition	3	A,B,C,D,E	4,3,2,1,0	12
Tap Changer Tank Leaks	1	A,B,C,D,E	4,3,2,1,0	4
Tap Changer Gaskets, seals, and pressure relief	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	5	A,B,C,D,E	4,3,2,1,0	20
			Total Score	240

By performing DGA, it is possible to identify internal faults, partial discharge ("PD"), low-energy sparking, severe overloading, and overheating in the insulating medium. Insulation power factor measurements are an important source of data to monitor transformer and bushing conditions. Lower scores for one or a combination of these condition parameters strongly indicate progressed degradation of the asset, hence their larger weights.

Power transformer peak loading is a good indication of loss of insulation life. The rate of insulation degradation is directly related to the operating temperature which is directly related to transformer loading levels. The peak loading level of the transformers is expressed in a percentage of the nameplate rating. PUC collects the substation load history monthly, recording the monthly peak.

PUC owns a total of thirty-four power transformers, eight of which are located in transmission stations ("TS"), TS1 and TS2. Figure 4-28 and Figure 4-29 present the age profile of power transformers in-service.

Figure 4-28: Substation Power Transformer Age Demographics

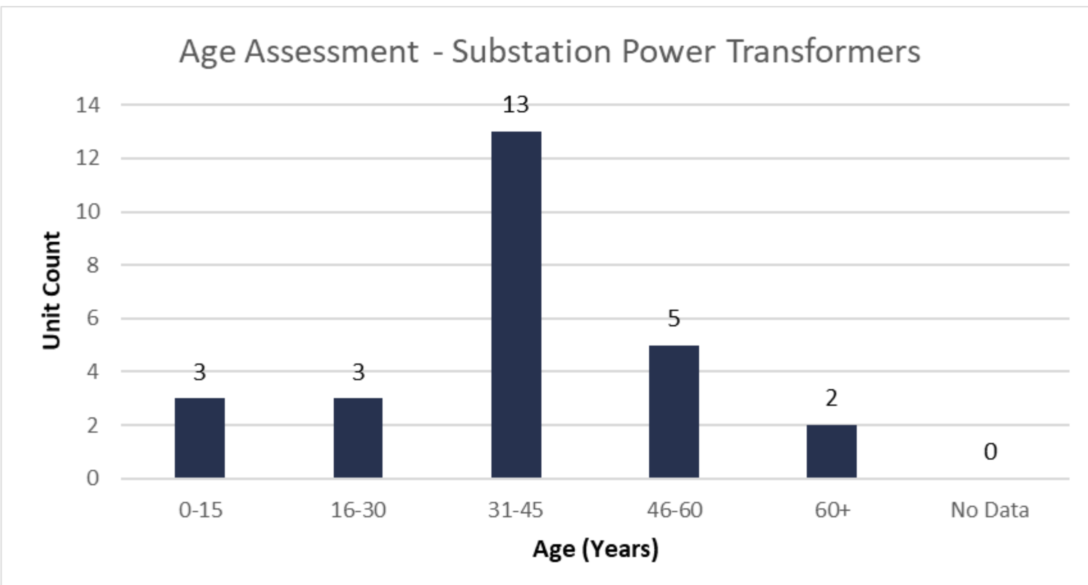
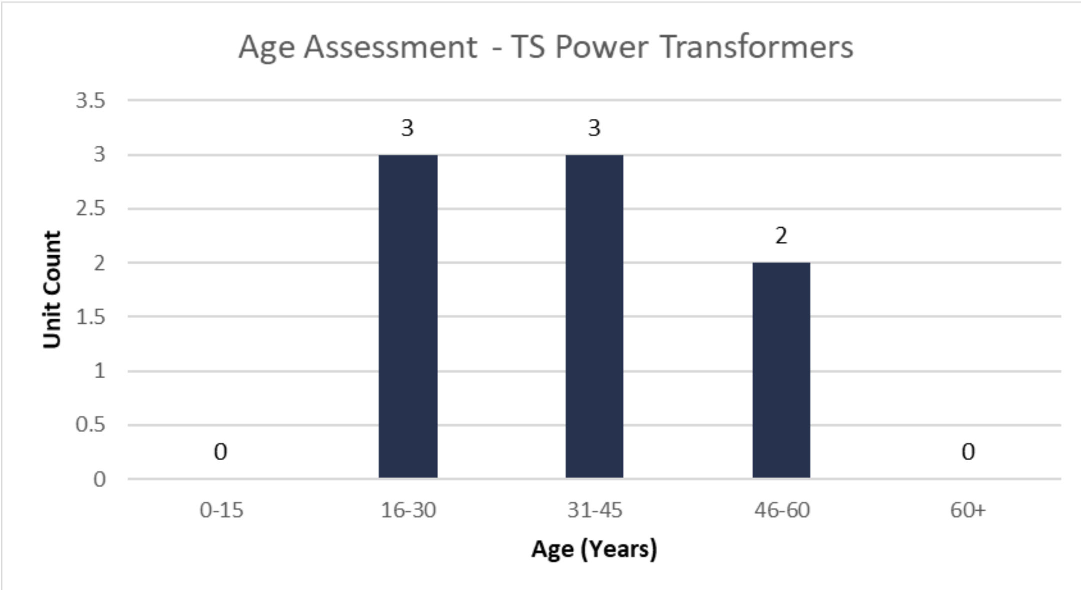


Figure 4-29: TS Power Transformer Age Demographics



PUC's power transformer inspections, test results, and loading history were used to calculate the HI based on the criteria provided in Table 4-8. The HI distributions for in-service power transformers are presented in Figure 4-30 and Figure 4-31 . Most power transformers lie between Fair and Very Good, while one transformer; Sub20_T1 is in Poor condition.

Figure 4-30: Substation Power Transformer HI Results

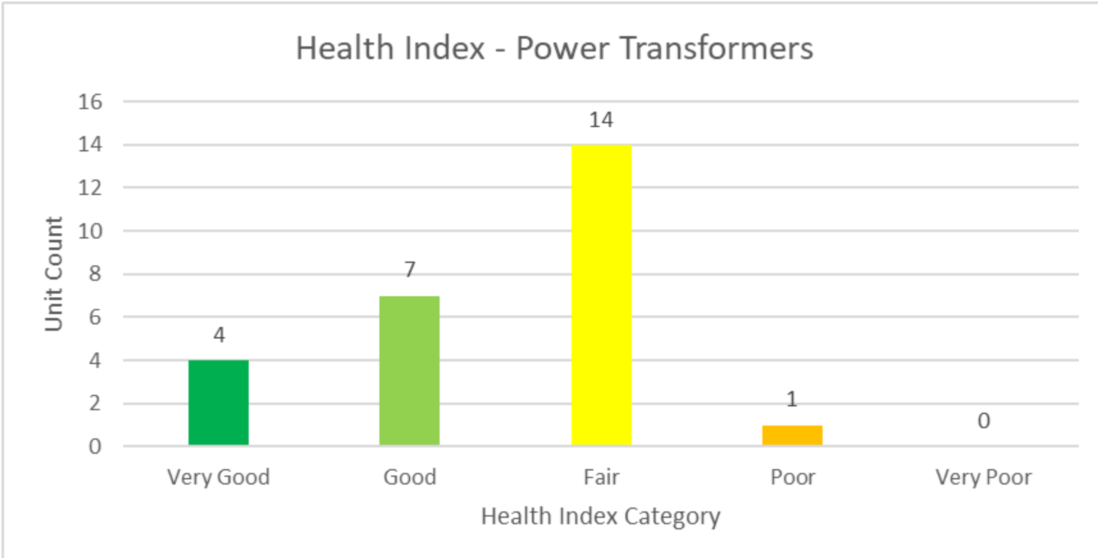
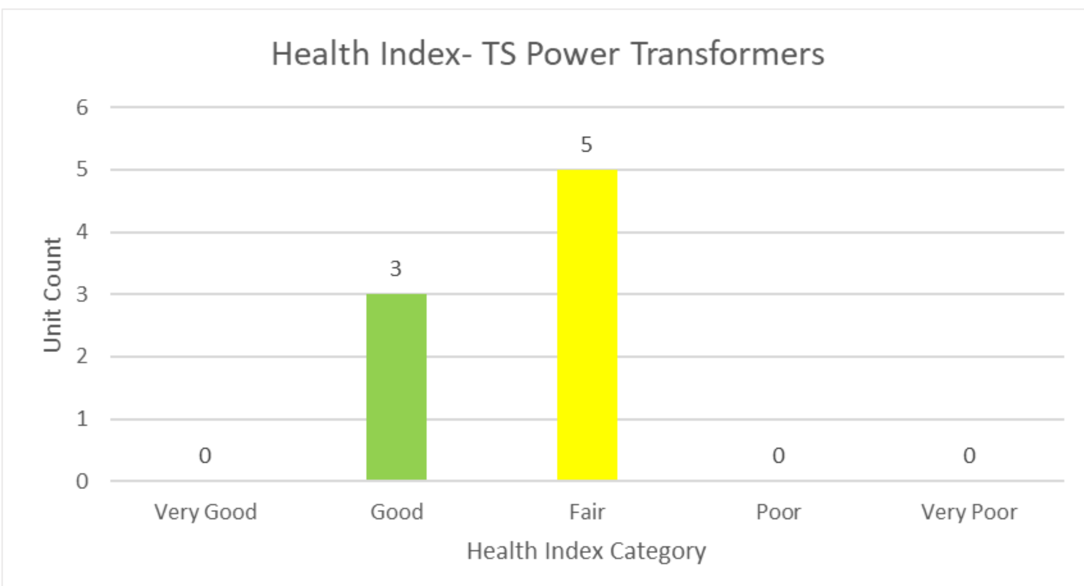


Figure 4-31: TS Power Transformer HI Results



In order to comprehend which assets have a high risk of failure, Table 4-9 below lists all the condition parameters that ranked at a "D" or an "E"; poor or very poor condition in the Health Index.

Table 4-9 "Red Flags" in Power Transformers

Asset ID	D Score	E Score	HI Score
Sub1_T1	Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks, Transformer Conservator/Oil Preservation System Condition	Service Age	59%
Sub 2_T3	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Transformer Conservator/Oil Preservation System Condition	Oil leaks	57%
Sub2_T4	Service Age, Transformer Main Tank/ Cabinet and Control Condition Transformer Conservator/Oil Preservation System Condition	--	63%
Sub4_T2	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks, Transformer Conservator/Oil Preservation System Condition	--	64%
Sub5_T1	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks, Transformer Conservator/Oil Preservation System Condition	--	65%
Sub5_T2	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks	--	64%
Sub11_T3	Service Age, IR Scan	--	62%

Asset ID	D Score	E Score	HI Score
Sub11_T4	Transformer Main Tank/ Cabinet and Control Condition, IR Scan	--	65%
Sub12_T4	Service Age	--	69%
Sub18_T1	Service Age, Oil Leaks,	--	63%
Sub18_T2	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks	--	57%
Sub19_T1	Transformer Main Tank/ Cabinet and Control Condition, IR Scan	--	75%
Sub19_T2	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Oil Leaks, IR Scan	IR Scan	59%
Sub20_T1	Service Age, Transformer Main Tank/ Cabinet and Control Condition, IR Scan	--	45%
Sub20_T2	Transformer Main Tank/ Cabinet and Control Condition, IR Scan	--	65%
Sub21_T2	DGA	--	73%
TS1_SM1	IR Scan	--	77%
TS1_SM2	Service Age, Transformer Main Tank/ Cabinet and Control Condition, Transformer Conservator/Oil Preservation System Condition	IR Scan	63%
TS1_SM3	Service Age, Transformer Main Tank/ Cabinet and Control Condition,	IR Scan	55%

Asset ID	D Score	E Score	HI Score
	Transformer Conservator/Oil Preservation System Condition		
TS1_SM4	Transformer Main Tank/ Cabinet and Control Condition	IR Scan	62%
TS2_TA1	Transformer Main Tank/ Cabinet and Control Condition	IR Scan	62%
TS2_TA2	Transformer Main Tank/ Cabinet and Control Condition	--	70%
TS2_TA3	Transformer Main Tank/ Cabinet and Control Condition	--	71%
TS2_TA4	Transformer Conservator/Oil Preservation System Condition	--	76%

4.2.2 Medium-Voltage Switchgear

Medium-voltage switchgear in PUC's substations operate at 34.5 kV, 12.47 kV, or 4.16 kV. They contain switching devices, circuit breakers, and measurement and control devices. Their functions are:

(a) To provide switching capability on the low or high side of the substation power transformers; and/or
(b) To protect feeders, transformers, and other equipment by opening the circuit under fault conditions.

PUC owns air magnetic and vacuum circuit breakers within switchgears operating at 12.47 kV. Air-magnetic breakers employ the magnetic effect of the current in their design, by forcing the electric arc produced during opening on the contacts into an arc chute. The arc chute causes elongation of the arc path and allows cooling, splitting and eventual extinction of the arc. In a vacuum circuit breaker, vacuum interrupters are employed to make or break load or fault current. Upon separation of the contacts, the current initiates a metal vapor arc discharge and flows through the plasma until the next current zero.

Computing the HI of a switchgear considers end-of-life criteria for its various components. Each criterion represents a factor critical in determining the component's condition relative to potential failure. The HI for medium-voltage substation switchgear is calculated by considering a combination of test results, service age, number of operations, and visual inspections as summarized in Table 4-10.

Table 4-10 Medium-Voltage Switchgear HI Formulation

Condition Parameter	Type	Weight	Ranking	Numerical Grade	Max Score
Insulation Resistance	All	4	A,B,C,D,E	4,3,2,1,0	16
Contact Resistance	All	2	A,B,C,D,E	4,3,2,1,0	8
Operations Count	All	3	A,B,C,D,E	4,3,2,1,0	12
Minimum Close Voltage Test	All	1	A,B,C,D,E	4,3,2,1,0	4
Minimum Trip Voltage Test	All	1	A,B,C,D,E	4,3,2,1,0	4
Maintenance Results	All	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	All	4	A,B,C,D,E	4,3,2,1,0	16
IR Scans	All	4	A,B,C,D,E	4,3,2,1,0	16
Service Age	All	6	A,B,C,D,E	4,3,2,1,0	24
				Total Score	**112**

Service age is given the highest weight as this equipment deteriorates more over time. Maintenance tests such as the insulation resistance test and IR inspection are also weighted the highest because they are the best indicator of the asset's condition and performance.

PUC owns 30 medium-voltage switchgears within its substations operating at 4.16 kV, 12.47 kV, and 34.5 kV. The age of the switchgears is known for 93% of the population. Figure 4-32 to Figure 4-34 presents the age distribution for switchgear by voltage level.

Figure 4-32: 4.16kV Substation Switchgear Age Demographics

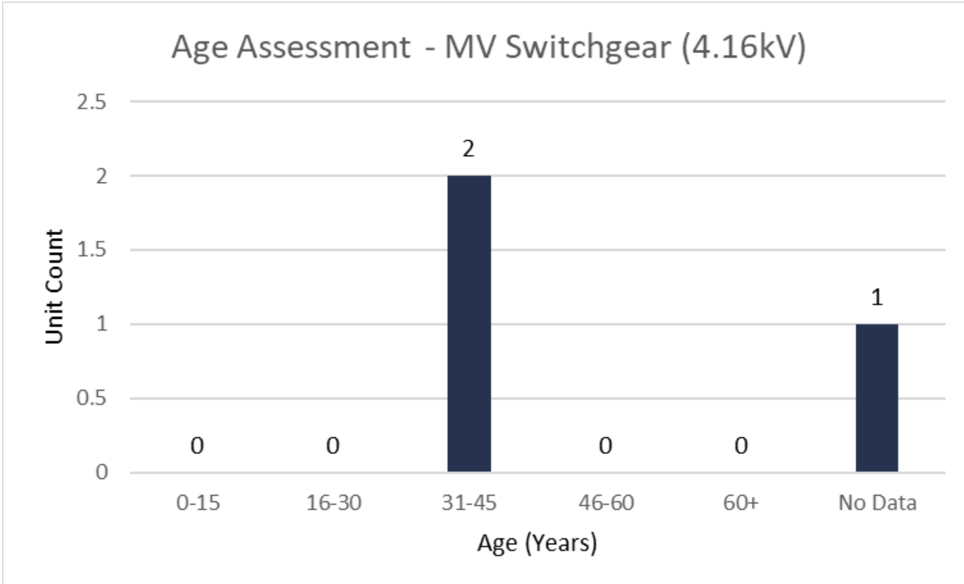


Figure 4-33: 12.47kV Substation Switchgear Age Demographics

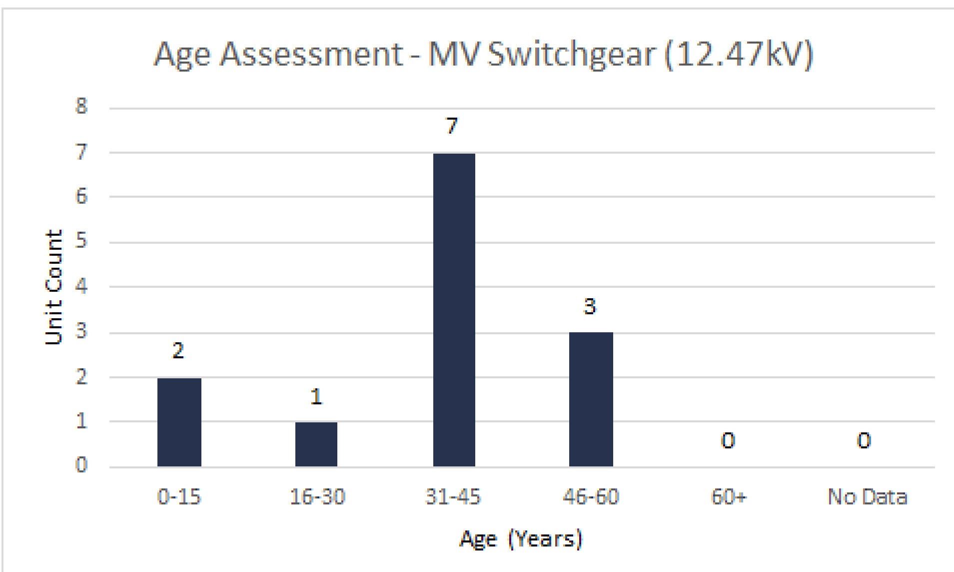
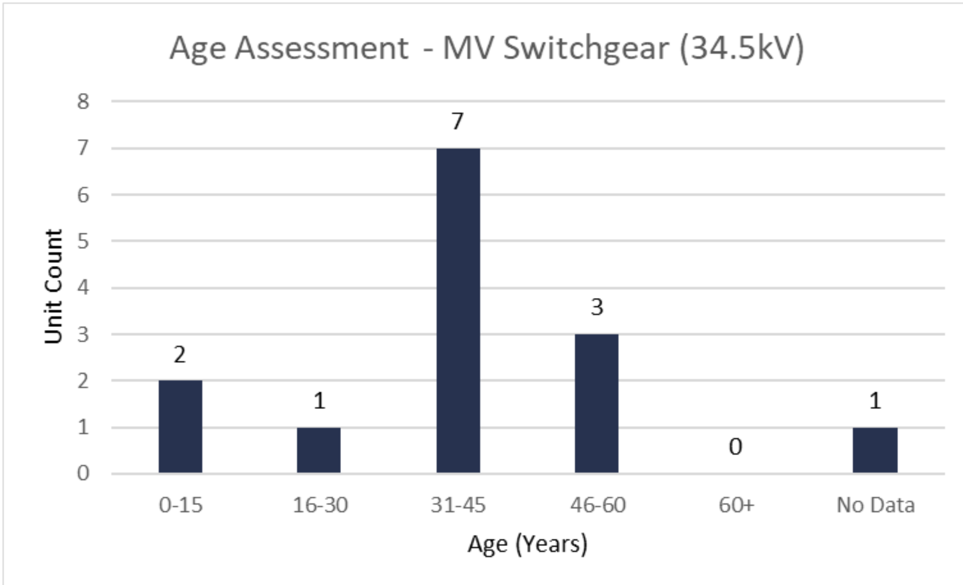
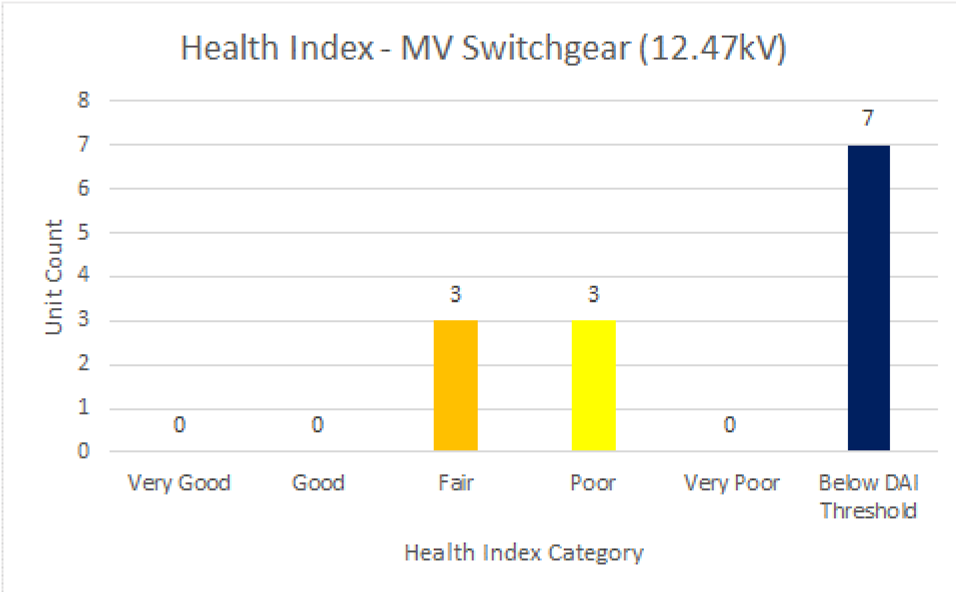


Figure 4-34: 34.5kV Substation Switchgear Age Demographics



A valid Health Index was calculated only for 12.47-kV switchgear. PUC's maintenance records, operation data, and visual inspections were used to calculate the HU based on the criteria provided in Figure 4-35. HI is known for 43% of the total population, all assets with a valid HI are in Fair or Poor condition, indicating the need for investment.

Figure 4-35: Medium-Voltage Switchgear HI Results



In order to comprehend which assets, have a high risk of failure, Table 4-11 below lists all the condition parameters that ranked at a “D” or an “E”; poor or very poor condition in the Health Index for the circuit breakers within the switchgears.

Table 4-11: “Red Flags” in MV Circuit Breakers

Asset ID	D score	E Score	HI
1-R1	Insulation Resistance, Contact Resistance	Minimum Close Voltage Test, Maintenance	45%
12-11	--	Contact Resistance, Minimum Close Voltage Test, Maintenance	54%
12-12	--	Contact Resistance, Minimum Close Voltage Test, Maintenance	54%
12-13	--	Contact Resistance, Minimum Close Voltage Test, Maintenance	54%
12-14	--	Contact Resistance, Minimum Close Voltage Test, Maintenance	54%

Asset ID	D score	E Score	HI
12-R3	Visual Inspection	Contact Resistance, Minimum Close Voltage Test, Maintenance	50%
12-R4	Visual Inspection	Contact Resistance, Minimum Close Voltage Test, Maintenance	50%
12-TB	--	Contact Resistance, Minimum Close Voltage Test, Maintenance, IR Scans	46%
13-01	Contact Resistance, IR Scan	Minimum Close Voltage Test, Minimum Trip Voltage Test	63%
13-02	Contact Resistance, IR Scan	Minimum Close Voltage Test, Minimum Trip Voltage Test	60%
13-03	IR Scan	Contact Resistance, Minimum Close Voltage Test, Minimum Trip Voltage Test	58%
13-04	Contact Resistance, IR Scan	Minimum Close Voltage Test, Minimum Trip Voltage Test	63%
13-R1	IR Scan	Contact Resistance, Minimum Close Voltage Test, Minimum Trip Voltage Test	58%
13-R2	Contact Resistance, IR Scan	Minimum Close Voltage Test, Minimum Trip Voltage Test	60%
15-01	--	Minimum Trip Voltage Test, IR Scan	61%
15-02	--	Minimum Trip Voltage Test, IR Scan	61%
15-03	--	Minimum Trip Voltage Test, IR Scan	61%
15-04	--	Minimum Trip Voltage Test, IR Scan	61%

Asset ID	D score	E Score	HI
15-R1	--	Minimum Trip Voltage Test	69%
15-R2	--	Minimum Trip Voltage Test, IR Scan	61%
18-01	Insulation Resistance, Visual Inspection, Service Age	Contact Resistance, Minimum Trip Voltage Test, IR Scan	35%
18-02	Service Age	Minimum Trip Voltage Test, IR Scan	54%
18-03	Insulation Resistance, Contact Resistance, IR Scan, Service Age	Minimum Trip Voltage Test	44%
18-04	Service Age	Contact Resistance, Minimum Trip Voltage Test, IR Scan	50%
18-R1	Service Age	Minimum Trip Voltage Test, IR Scan, Maintenance	44%
18-R2	IR Scan, Service Age	--	63%
20-01	Contact Resistance, Maintenance, IR Scans	--	56%
20-02	Maintenance	Contact Resistance, IR Scan	51%
20-03	Maintenance, IR Scan	Contact Resistance	55%
20-04	--	Contact Resistance, IR Scan	65%
20-R1	Maintenance	Contact Resistance, IR Scan	51%
20-R2	--	Contact Resistance, IR Scan	59%

4.2.3 34.5-kV TS Circuit Breakers

Outdoor circuit breakers are stand-alone electrical devices that operate automatically during a fault. It protects other electrical assets from damage due to short-circuit current. It operates when a fault is detected and can be programmed to automatically restore the connection once the fault is cleared or can be reset manually based on the severity of the fault.

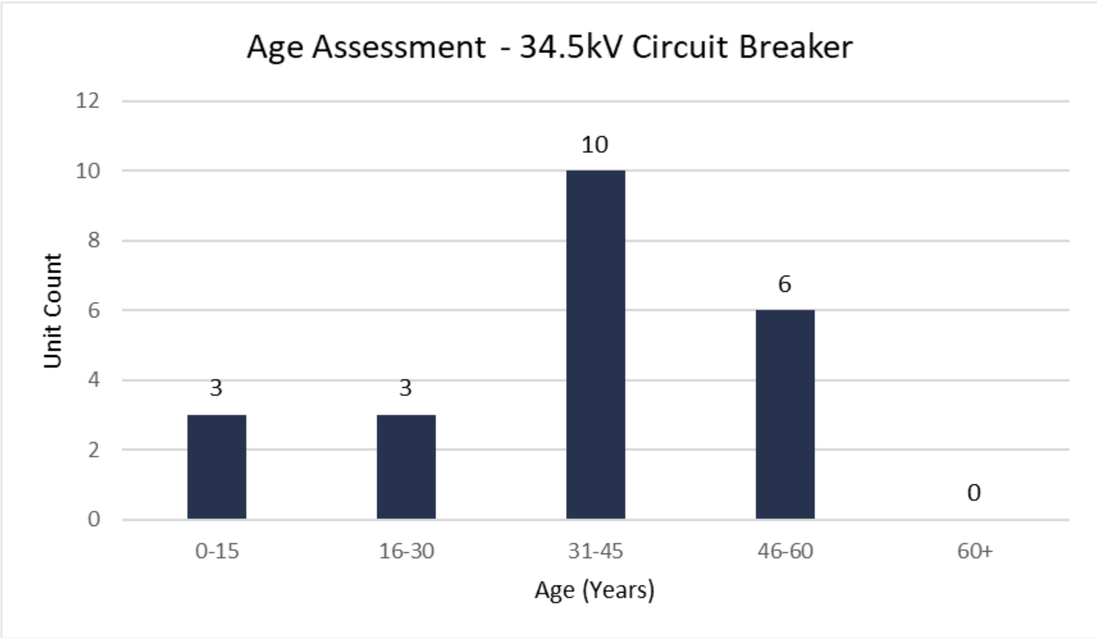
PUC owns twenty-two circuit breakers operating at 34.5 kV: seventeen oil circuit breakers, three vacuum circuit breakers, and two SF6 circuit breakers, located at TS1 and TS2. Table 4-12 summarizes the methodology to generate the Health Index for High Voltage circuit breakers.

Table 4-12: 34.5 kV TS Circuit Breaker HI Formulation

Condition Parameter	Type	Weight	Ranking	Numerical Grade	Max Score
Insulation Resistance	All	4	A,B,C,D,E	4,3,2,1,0	16
Contact Resistance	All	4	A,B,C,D,E	4,3,2,1,0	16
Close Travel Analysis	All	1	A,B,C,D,E	4,3,2,1,0	4
Open Travel Analysis	All	1	A,B,C,D,E	4,3,2,1,0	4
Bushing/support Insulators	All	4	A,B,C,D,E	4,3,2,1,0	16
Tank and mechanism box	All	4	A,B,C,D,E	4,3,2,1,0	16
Overall breaker condition	All	4	A,B,C,D,E	4,3,2,1,0	16
Foundation/Support Steel/Grounding	All	3	A,B,C,D,E	4,3,2,1,0	12
Oil Leaks	Oil	2	A,B,C,D,E	4,3,2,1,0	8
Service Age	All	4	A,B,C,D,E	4,3,2,1,0	16
IR Scans	All	4	A,B,C,D,E	4,3,2,1,0	16
				Total Score	**140**

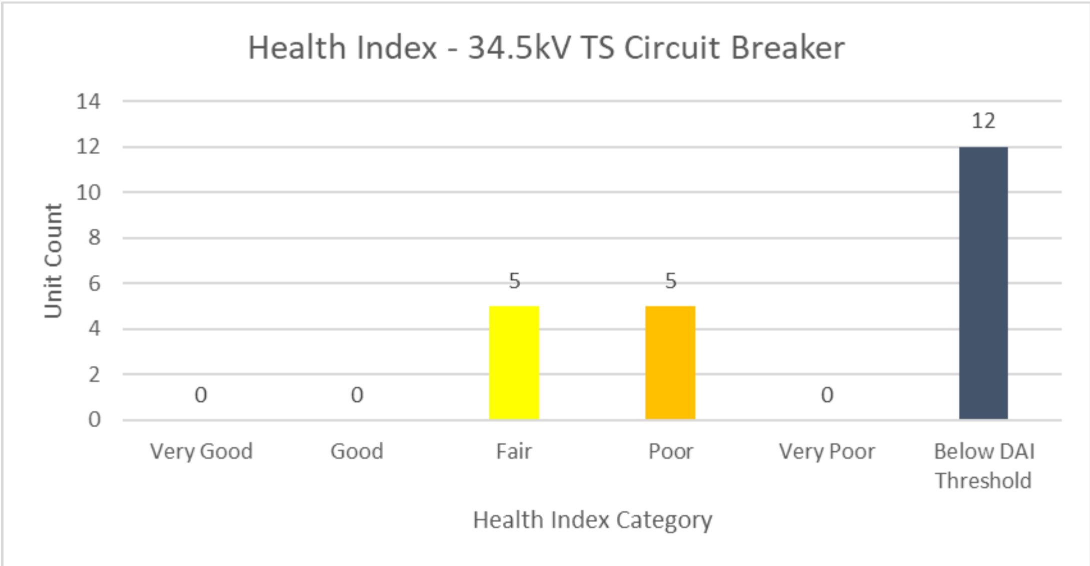
The installation date is known for the entirety of the population. The age distribution for 34.5-kV circuit breakers is shown in Figure 4-36.

Figure 4-36: 34.5-kV TS Circuit Breaker Age Demographics



The HI distribution for in-service 34.5kV circuit breakers is presented in Figure 4-37. The HI is known for 45% of the population and their condition lies in either Fair or Poor condition.

Figure 4-37: 34.5-kV TS Circuit Breaker HI Results



In order to comprehend which assets have a high risk of failure, Table 4-13 below lists all the condition parameters that ranked at a "D" or an "E"; Poor or Very Poor condition in the Health Index.

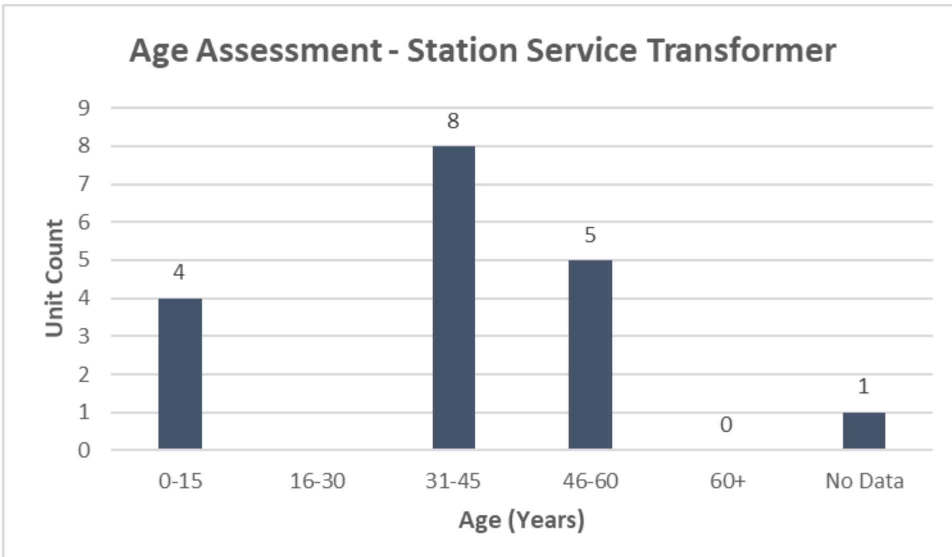
Table 4-13: "Red Flags" in 34.5-kV TS Circuit Breakers

Asset ID	D score	E Score	HI
TS1-SM4	Insulation Resistance, Contact Resistance, Tank & Mechanism Box	IR Scan	47%
TS1-SM5	Insulation Resistance, Tank & Mechanism Box	Contact Resistance, IR Scan	44%
TS1-SM7	Contact Resistance, Tank & Mechanism Box, Service Age	Close Travel Analysis, IR Scan	51%
TS1-SM9	Contact Resistance, Service Age	IR Scan	58%
TS1-SM11	Contact Resistance, Service Age	IR Scan	51%
TS2-TA1	Insulation Resistance, Contact Resistance, Tank & Mechanism Box, Overall Breaker Condition, Oil Leaks, IR Scan	--	44%
TS2-TA2	Contact Resistance, IR Scan	Insulation Resistance	50%
TS2-TA3	Contact Resistance, IR Scan, Tank & Mechanism Box	Insulation Resistance	46%
TS2-TA6	Contact Resistance, IR Scan, Tank & Mechanism Box	--	56%
TS2-TA7	Contact Resistance, Tank & Mechanism Box, Oil Leaks	IR Scan	47%

4.2.4 Station Service Transformers

Station service transformers supply power to auxiliary equipment in the station including the charger for station DC and batteries, SCADA and communications infrastructure, lights, equipment and building heaters and security systems. Often, these assets can be encased in enclosures and are difficult to assess or read the nameplate without taking an outage. PUC owns eighteen station service transformers. Installation date is known for most of the population. Due to the unavailability of inspection data for station service transformers, health indices were not calculated. The age distribution of station service transformer is illustrated in Figure 4-38.

Figure 4-38: Station Service Transformer Age Demographics



4.2.5 Battery Banks and Chargers

The battery system provides backup power to essential station functionalities such as lighting, communication, and protection/control equipment in the event of a loss of supply to the station. The main components of the battery system are the charger and the battery bank which is comprised of several battery cells in series.

The HI formulations for battery banks and chargers are combined based on age, test results, and visual inspection results. Age provides insight into the remaining useful life of the asset based on the typical useful lives of DC systems seen across the industry. Batteries also operate based on a determinate chemical process, which has a known lifetime and useful duration. Table 4-14 summarizes the methodology to generate the Health Index for station batteries.

Table 4-14: Station Battery and Charger HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Age of Battery	4	A,B,C,D,E	4,3,2,1,0	16
Age of Charger	4	A,B,C,D,E	4,2,0	16
Electrolyte Level	3	A,C,E	4,2,0	12
Connections	2	A,B,C,D	4,3,2,1	8
Straps/ Cables	2	A,B,C,D	4,3,2,1	8
Battery Cells and trays/tracks	2	A,B,C,D	4,3,2,1	8
Individual Cell Voltage	1	A,B,C,D,E	4,3,2,1,0	4
Internal & Intercell Resistance	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**84**

PUC owns seventeen batteries and chargers within its stations. The asset installation years are known for all battery banks and chargers. Figure 4-39 to Figure 4-42 present the age distributions for station battery banks and chargers.

Figure 4-39: Substation Battery Banks Age Demographics

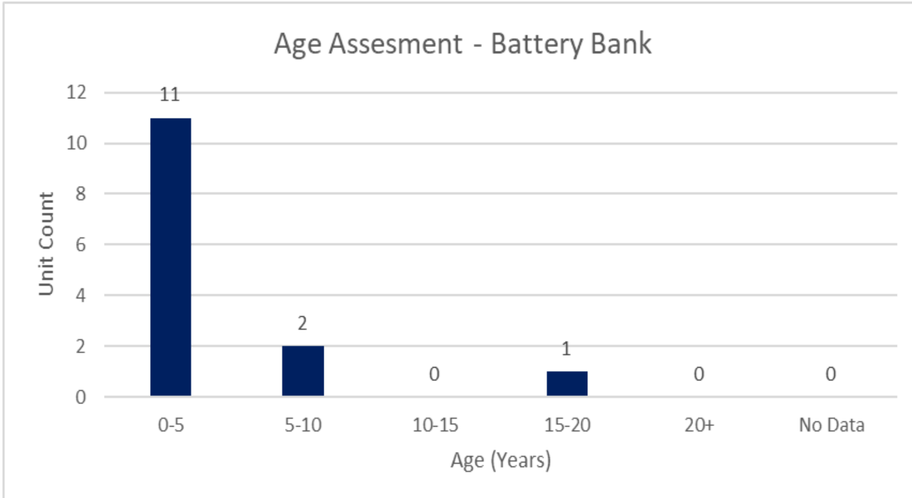


Figure 4-40: TS Battery Bank Age Demographics

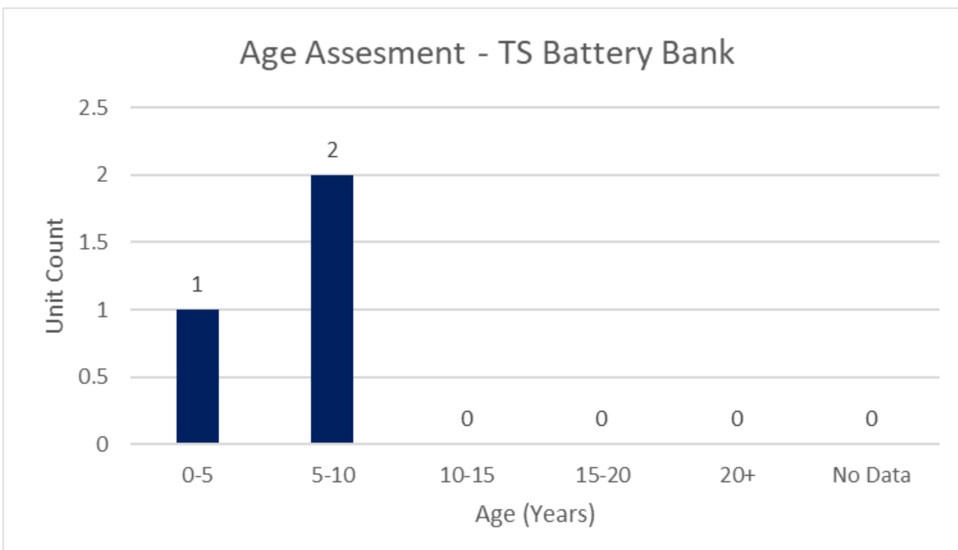


Figure 4-41: Substation Battery Charger Age Demographics

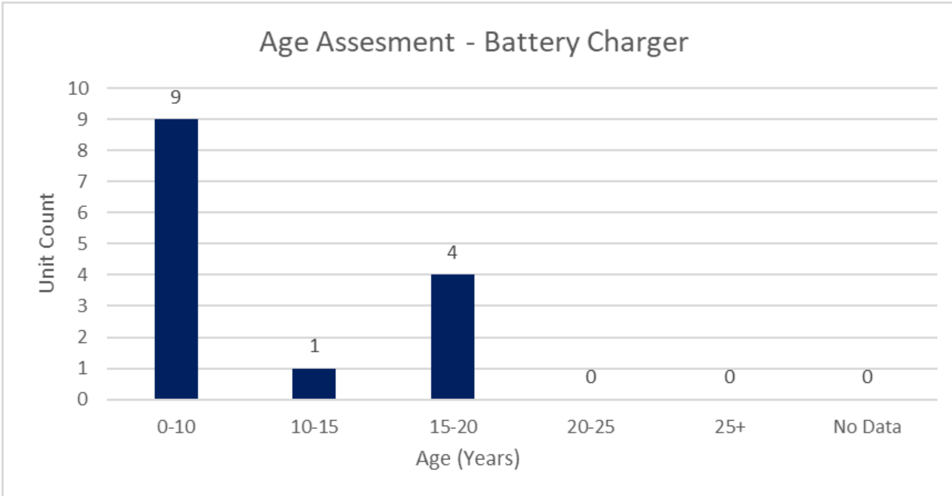
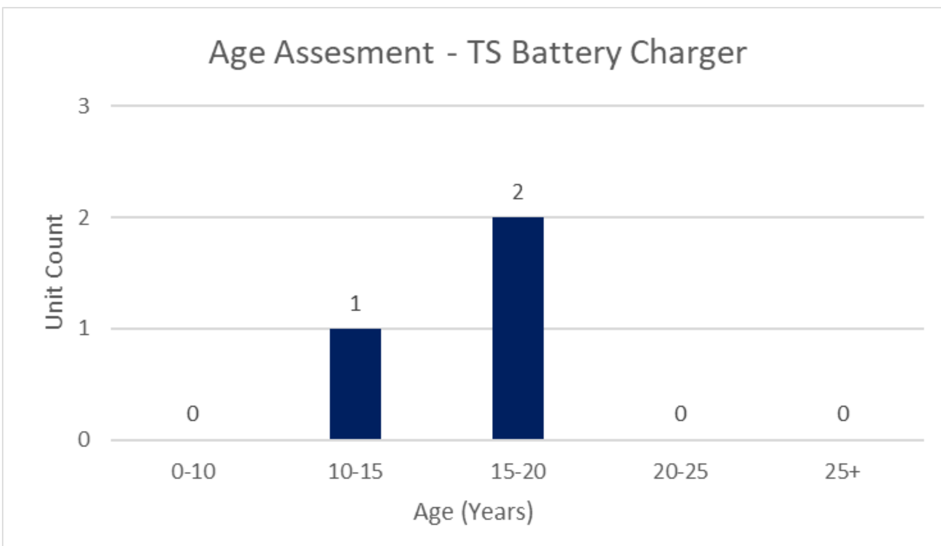


Figure 4-42: TS Battery Charger Age Demographics



The maintenance test results and visual inspection information for PUC's battery banks and chargers were used to calculate the HI based on the criteria listed in Table 4-14. The HI distributions for station batteries are presented in Figure 4-43 and Figure 4-44. Most batteries were in Good or Very Good condition.

Figure 4-43: Substation Battery HI Results

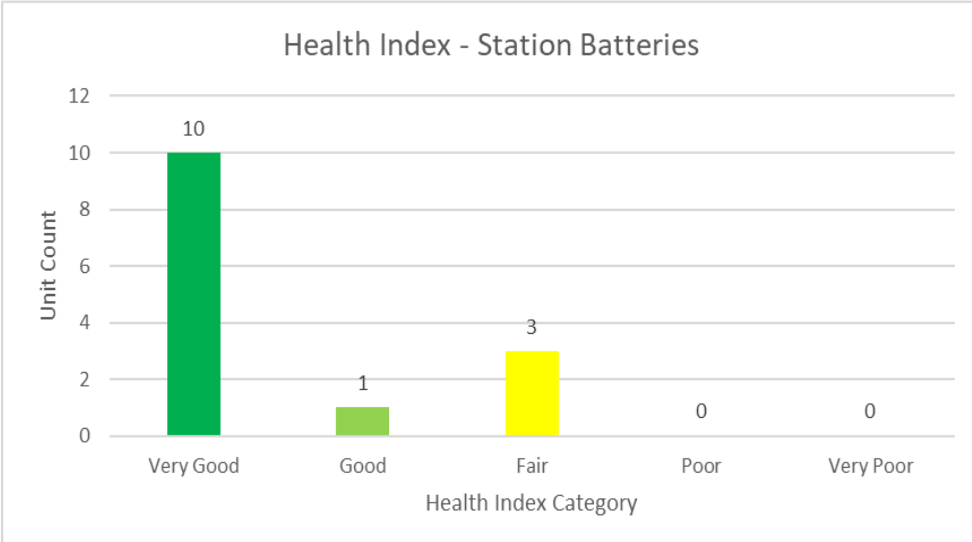
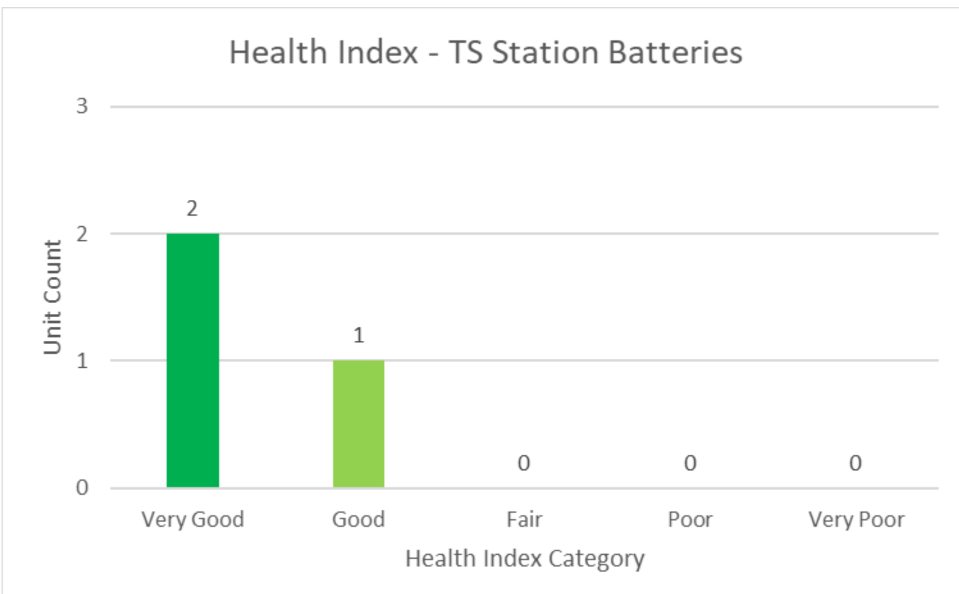


Figure 4-44: TS Station Battery HI Results



4.2.6 Station Buildings

The primary function of buildings at stations is to provide a suitable environment for electrical equipment or to serve as a base for administrative and service work. To achieve this, they must be weatherproof. Interaction with the environment poses a continuous threat to the integrity of buildings. Regular preventative maintenance, undertaking minor repairs, painting, etc., are essential to ensure the long-term viability and integrity of buildings.

For buildings containing electrical equipment the critical factor is preventing water ingress. Roof maintenance is therefore the most significant issue for transmission buildings. Regular preventative maintenance with occasional major refurbishment of roofs, windows and doors should enable buildings to have long lifetimes. It is likely that for well-maintained buildings end-of-life will be for operational, non-condition, reasons.

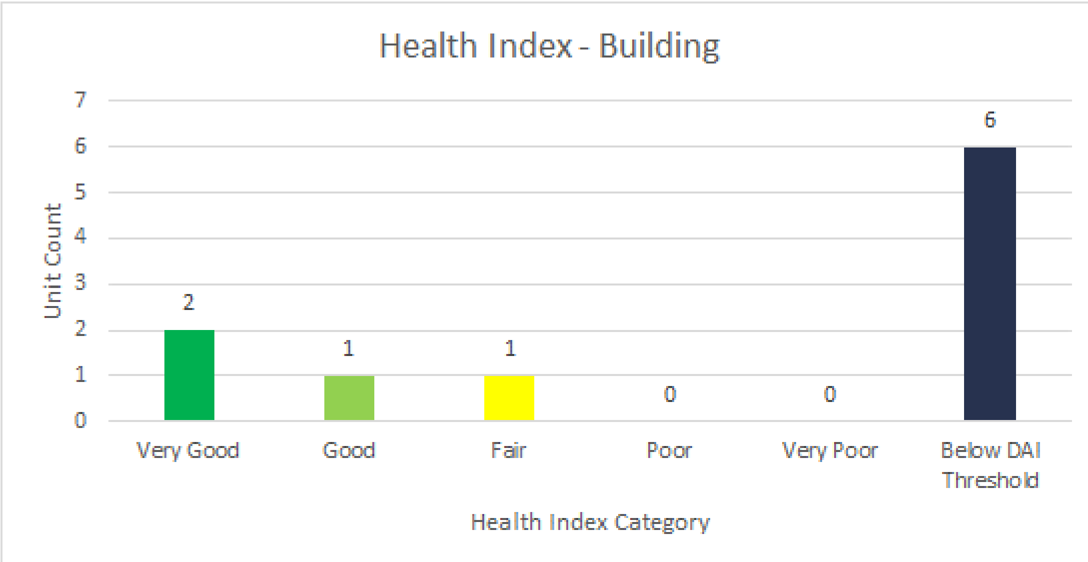
PUC owns a total of ten substation buildings and their visual inspection criteria used to develop its health index is shown below in Table 4-15.

Table 4-15: Station Building HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Roof Condition	4	A,B,C,D,E	4,3,2,1,0	16
Wall Condition	4	A,B,C,D,E	4,3,2,1,0	16
Doors/Windows/Louvres	2	A,B,C,D,E	4,3,2,1,0	8
Floors/Foundations	4	A,B,C,D,E	4,3,2,1,0	16
Overall Condition	4	A,B,C,D,E	4,3,2,1,0	16
			Total Score	**72**

Visual inspections were used to calculate the HI based on the criteria listen in Table 4-15. The HI distribution for station buildings is presented in Figure 4-45.

Figure 4-45: Station Building HI Results



4.2.7 Station Fences

The integrity of fences, contribute the safety of the station and the performance of the assets therein. Fences protects the public from hazardous electrical contacts, and to protect facilities against intrusion and vandalism.

The HI for Station Fences is calculated by using visual inspection results. Table 4-16 summarizes the HI formulation for station facilities. The condition parameters focus on the physical condition of the fence since a grounding study was not part of the scope of this assessment. PUC should consider a grounding study for its TS and substations in the future, particularly if there are issues of copper theft.

Table 4-16 – Station Fences HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Grounding	2	A,C,E	4,2,0	8
Fence Bottom Gap	3	A,C,E	4,2,0	12
Gate Condition/ Operation	3	A,C,E	4,2,0	12
Barbed Wire	3	A,C,E	4,2,0	12
Fence Fabric	4	A,C,E	4,2,0	16
Slanted or frost-affected fence posts	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**72**

There are twelve station fences within PUC's service territory: ten at substations and two at TS. Visual Inspections were used to calculate the HI based on the criteria listed in Table 4-16. The HI distributions for station fences are presented in Figure 4-46 and Figure 4-47. All the population are in Very Good or Good condition.

Figure 4-46: Substation Fence HI Results

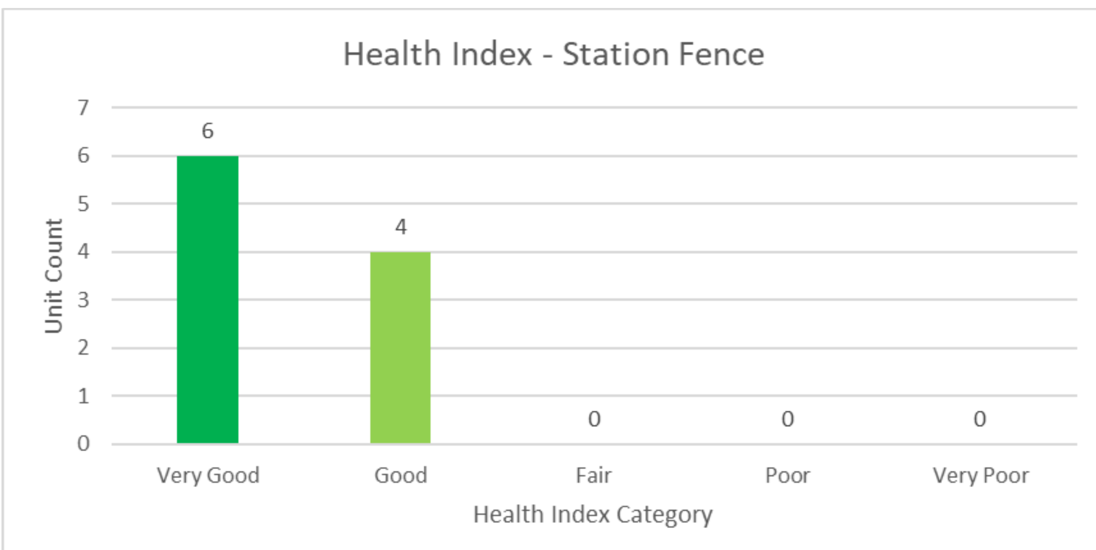
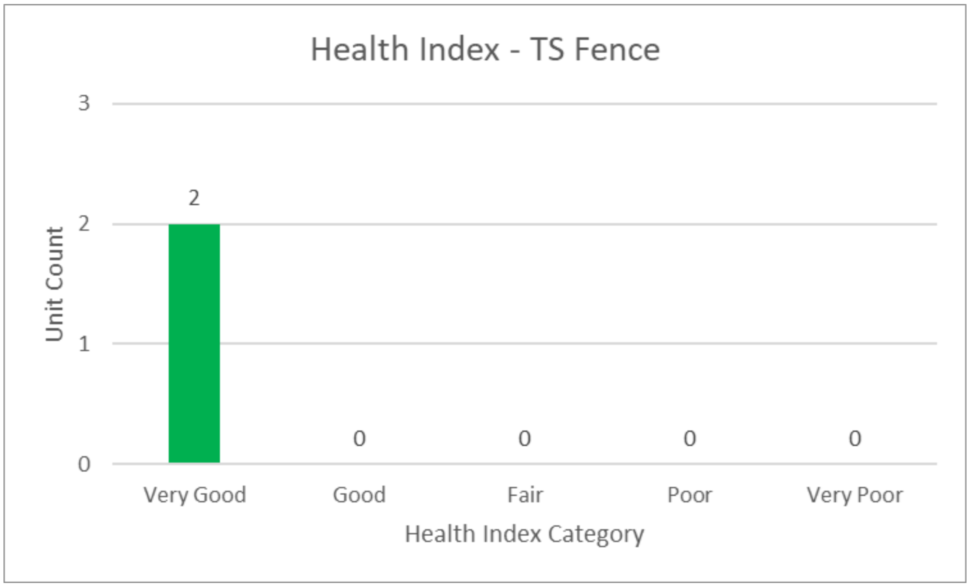


Figure 4-47: TS Fence HI Results



4.2.8 Station Riser Cables

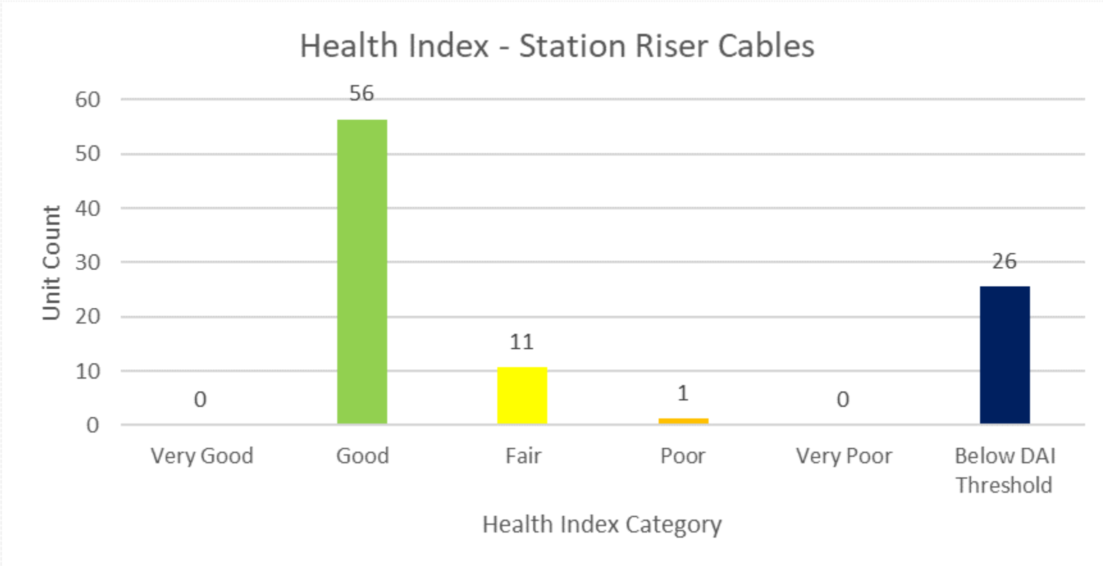
Riser cables provide a transition from underground cables to overhead lines at the egress of the station. They are critical since they carry the entire load of the feeder.

Table 4-17: Station Riser Cable HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
IR Scans	1	A,B,C,D,E	5,4,3,2,1	5
			Total Score	**5**

PUC owns approximately 94 riser cables within their stations. The HI for station riser cables is calculated by considering the infrared scan assessment. As shown in Figure 4-48 below, a valid HI was calculated for 78% of riser cables with 71% scoring in Fair or Good condition.

Figure 4-48: Station Riser Cable HI Results



4.2.9 115-kV Switches

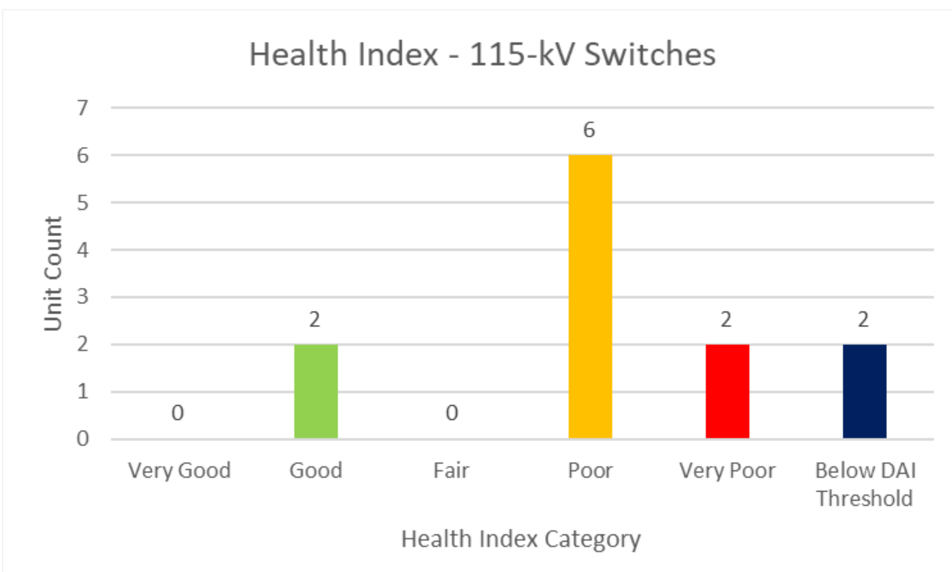
TS switches rated for 115 kV are used to remotely isolate equipment during planned maintenance and unplanned switching operations. The HI for 115-kV switches summarized in Table 4-18 is calculated by considering a combination of visual inspection results and the ability to operate the switches safely.

Table 4-18: 115-kV Switches HI Formulation

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	5	A,B,C,D,E	4,3,2,1,0	20
Operation	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**32**

PUC owns twelve 115-kV switches within its two TS. A valid HI was developed for ten of the 115-kV switches where the remaining two were not inspected. As seen in Figure 4-49, six of the switches are in Poor condition and two are in Very Poor condition. While PUC does operate these switches safely, PUC must isolate the switches which causes inconvenience for customers and is also a costly operation. These switches should be planned for replacement to allow for more efficient operation whilst minimizing impacts felt by customer whilst operating these switches.

Figure 4-49: 115-kV Switches HI Results



5 Conclusions

As Figure 5-1 to Figure 5-3 indicate, most assets across PUC's asset classes analyzed are in Fair condition or better. This can indicate PUC has taken steps in the past to manage their asset health and performance for the benefit of its customers. As with every system, however, there are areas that require PUC's attention in the coming years where asset populations contain material portions of equipment in or approaching Poor condition or worse.

Figure 5-1: Distribution Asset Health Index Results

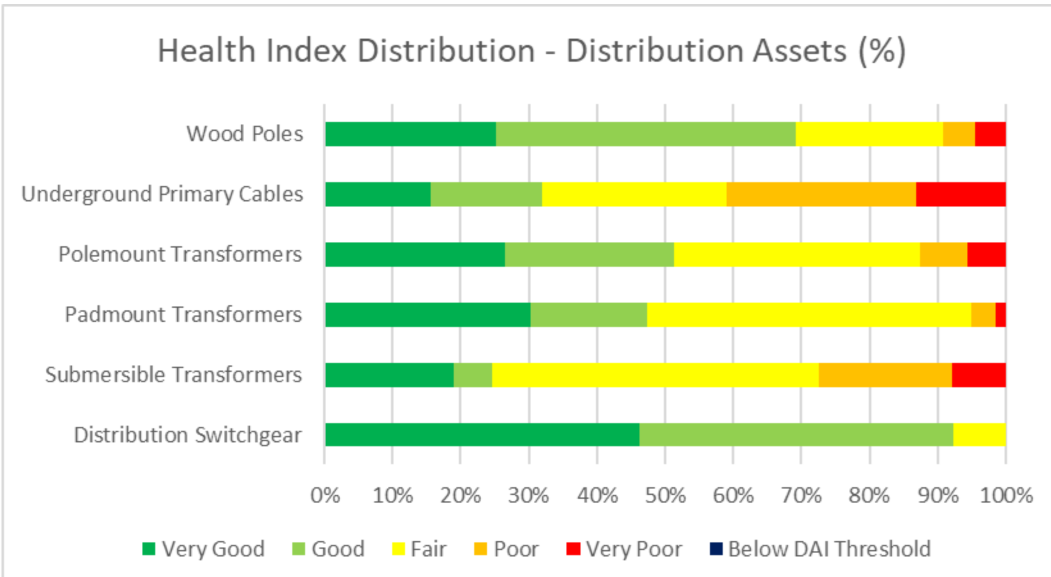


Figure 5-2: Substation Asset Health Index Results

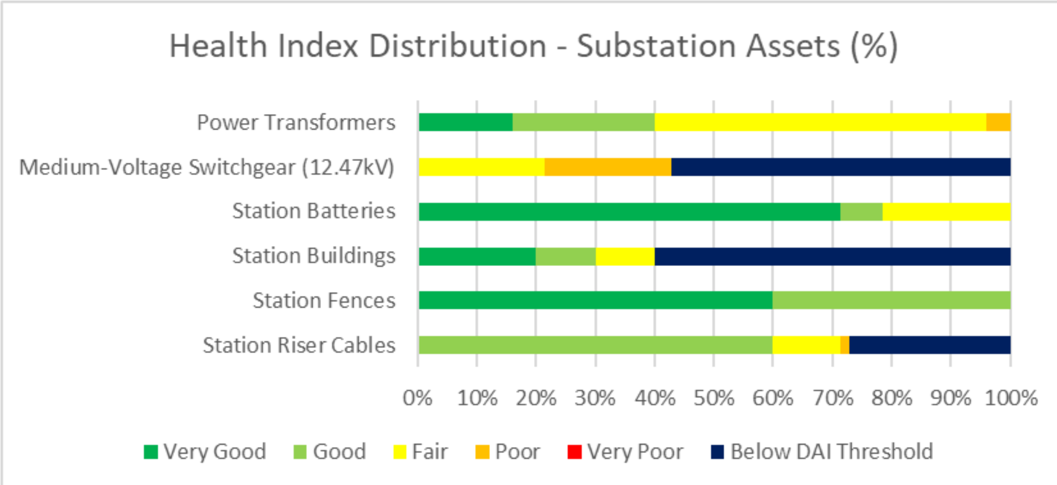
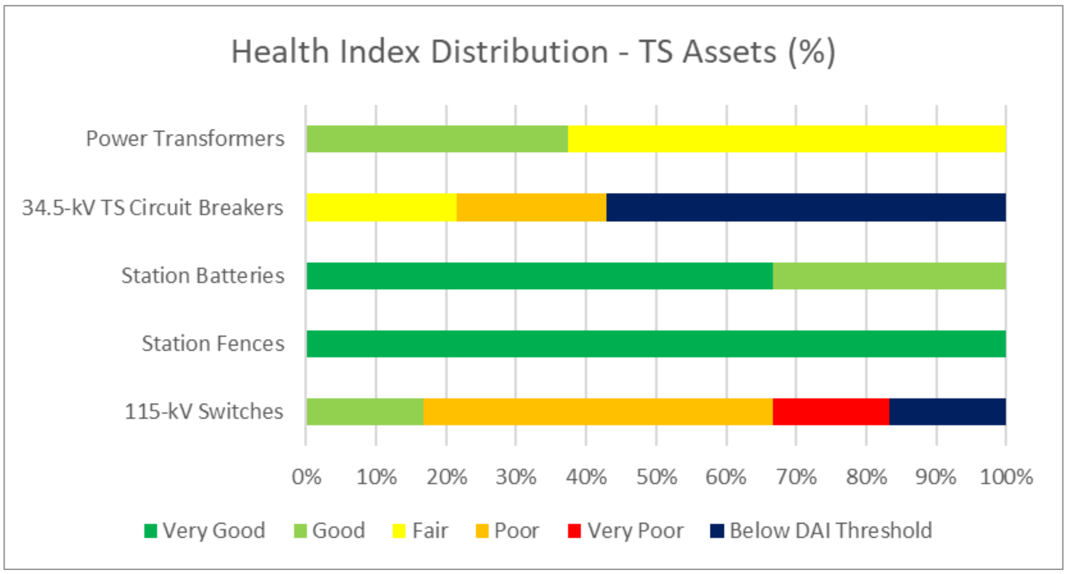


Figure 5-3: TS Asset Health Index Results



A condition-based replacement strategy could ostensibly focus on assets in Poor and Very Poor condition over the short-term. Fair condition assets should also be considered for replacement over the short-term, depending on risk/criticality. Substation and TS assets are often critical and may warrant replacement over the short-term if in Fair condition. Fair-condition assets should also be considered when developing long-term asset replacement plans.

6 Recommendations

A complete ACA framework for PUC represents an integral component of its broader AM framework, enabling it to proactively manage its distribution assets and ensure that the right actions are taken for the right assets at the right time. This framework leveraged the information captured from maintenance programs and other utility records, creating an essential linkage between the ongoing maintenance activities and the capital investment decision-making process. Leveraging the HI insights allows for PUC's investment decision-making to be further enhanced with the current information regarding the state of the assets. There are also further opportunities to introduce new data collected, improve on data availability, and continuously improve the ACA framework.

This section breaks down METSCO's recommendations into the following categories:

1. Asset intervention strategies;
2. HI improvements; and
3. Data availability improvements.

6.1 Asset Intervention Strategies

Asset intervention options include replacement, refurbishment, or enhanced maintenance. Assets in Poor or Very Poor condition should be prioritized for intervention in the short-term. Fair-condition assets may also need to be addressed in the short-term, depending on risk. Long-term planning considerations should also consider the number of assets in Fair condition that will continue to degrade and the age profile of the assets. For example, the large number of poles installed by PUC in the 1970s and 1980s will severely pressure PUC's budget and reliability in the future if not proactively planed for.

Where feasible, asset intervention should be bundled; for example, into overhead rebuild projects, underground rebuild projects, and substation rebuild projects. While secondary bus and services were not assessed as part of this ACA, it is often economical to replace secondary bus and/or services at the same time as the primary cables/conductors in the rebuild projects. This avoids return trips to make repairs along the same feeder as secondary networks fail.

6.2 Health Index Improvements

For select asset classes, a recommended HI formulation was used for PUC's ACA framework. The following set of recommendations target additional condition parameters that can be incorporated for specific asset classes to improve the HI formulation and provide PUC with additional data to refine its asset condition calculations. The recommendations are based on improving the ACA framework over time and should not be interpreted as suggesting that immediate action is warranted. The following tables highlight the condition parameter name, a short description of the reasoning to include the condition parameter, and a priority of importance to include it into the specific asset's class HI framework. The priority is dependent on the condition parameter's weighting in comparison to the current HI framework condition parameter's weights.

1. Wood Poles

Parameters which are already covered by PUC's inspectors and contractors should be explicitly added to inspection forms so they can be included in future HI formulations.

Table 6-1: Data Collection Recommendation for Wood Poles

Criteria	Reasoning	Priority
Wood Rot	Wood rot identifies the degree of surface or internal decay and can be determined without use of special equipment.	**Medium**
Out of Plumb	Pole with excessive lean face a different load profile and are more prone to failure during extreme weather events.	**Low**

2. Underground Primary Cables

PUC has not experienced many cable failures on its system until the previous few years; however, should their rate of failure continue increase, then it would be prudent to perform more detailed analysis into cables. Recommended analyses include detailed post-mortem analysis of failed cable samples, aggregate failure/reliability analysis linked to underground cables, and cable testing to ascertain in-field condition. Cable loading is also a useful indicator of thermal degradation.

Table 6-2: Data Collection Recommendation for Underground Cable

Criteria	Reasoning	Priority
Aggregate Cable Failure Analysis	Collecting high-quality failure and reliability data for all assets – including cables – is critical for understanding the reliability of the system. PUC should establish a rigorous progress for coding failure and reliability data by the asset or event from which the failure originated.	**High**
Post-mortem Analysis	Identifying water tree samples throughout the service territory and varying age, the utility would be able to have an improved view on cable conditions within the system.	**High**
Condition of Concentric Neutral	Corrosion of concentric neutrals is another mode of degradation. Insulation degradation and cable failures can be accelerated if the cable jacket is damaged allowing moisture to enter into the insulation system. Concentric neutral corrosion is a major problem particularly on unjacketed cables or when the neutrals of the cable are exposed to excessive moisture over time. The corrosion can lead to premature cable failures and/or cause touch potential risks. Time Domain Reflectometry (TDR) tests are performed to determine the degree of corrosion on concentric neutral cables.	**Medium**
Loading History	Cable degradation can also occur due to overheating under overloading or short circuit conditions. Over stressing of insulation during voltage surges can also lead to cable failures.	**Low**

3. Pole-mount Distribution Transformers

Pole-mount transformers are inspected as part of the regular line patrol process, but these results are not logged. A detailed visual inspection of the pole-mount transformer can be done during line patrols, pole inspections, or other programs, and the results recorded for use in the ACA. IR scans can detect hot spots in the tank or connectors.

Table 6-3: Data Collection Recommendation for Overhead Distribution Transformers

Criteria	Reasoning	Priority
Visual Inspection	To identify if the transformer is subject to any physical damage, oil leak, or corrosion.	**Medium**
IR Scans	To identify hotspots on the tank, connectors, etc. during transformer operation.	**Low**

4. Pad-mount and Submersible Distribution Transformers

IR scans can also be applied to submersible and pad-mount transformers. Pad-mount transformers can be more difficult and costly to scan since the box needs to be opened, requiring a hold-off.

Table 6-4 : Data Collection Recommendation for Distribution Transformers

Criteria	Reasoning	Priority
IR Scans	To identify hotspots on the tank, connectors, etc. during transformer operation.	**Medium**

5. Underground Switches

Similar to distribution transformers, underground switches can be checked for hotspots using an IR camera.

Table 6-5: Data Collection Recommendation for Underground Switches

Criteria	Reasoning	Priority
IR Scans	To identify hotspots on the switch contacts, etc. when carrying current.	**Medium**

6. Station Power Transformers

PUC has a robust inspection and preventative maintenance program for station power transformers. The following tests are commonly applied by utilities in Ontario and can supplement PUC's present-day program to help identify adverse conditions before they develop into failures.

Table 6-6: Data Collection Recommendation for Power Transformers

Criteria	Reasoning	Priority
Turns Ratio Test	To compare the actual turns ratio vs. design rating and between phases.	**Low**
Winding Resistance	To identify degradation of the transformer winding based on the measured resistance.	**Low**

7. Station Riser Cables

Since PUC's station riser cables are aged and carry the full load of the feeder, PUC should prioritize collecting nameplate, visual inspection, and loading for these assets to form a condition assessment in the future.

Table 6-7: Data Collection Recommendation for Station Riser Cables

Criteria	Reasoning	Priority
Visual Inspection	To identify chips/cracks in the arrester, degradation of the cable terminations, or corrosion of the riser.	**High**
Loading	To identify overloaded cables that are undergoing increased thermal stresses.	**High**

6.3 Data Collection Improvements

Data availability is critical to produce prudent, accurate, and justified decision-making outputs. It represents the single most important element that can influence the degree to which the AM decision-making relies on objective factors. Companies understand that it is critical to execute continuous improvement procedures through an AM data lifecycle, such that data gaps and inaccuracies can be addressed and mitigated. In the case of this ACA, the quality of the HI is dependent on the available data. For condition parameters with low data availability METSCO recommends that PUC continue collecting the information related to these data points.

Additionally, for an asset to have a valid HI, it must meet a minimum 70% of available data across the condition parameters used in the HI formulation for distribution assets and 65% for station. As part of future improvement opportunities, it is recommended that PUC continue capturing asset data for condition parameters that are currently available for a small proportion of the asset population, such that valid Health Indices can be produced across the population. It is expected that with every passing year, the inspection record database will continue to grow, allowing for Health Indices to be calculated for the remaining population.

Lastly, METSCO noticed that some condition parameters recorded by PUC vary in the detail with respect to the grading scheme. Some parameters will have a three-tier grade (e.g., Good, Fair, and Poor) and others may have five levels (e.g., from Very Good to Very Poor). METSCO recommends for PUC to evaluate options of changing some condition parameters recorded to a five-level grade, as doing so can provide more defined segregation between assets that need immediate attention and those that can still be in-service without intervention in the short term.

METSCO recommends that PUC continue to work on mitigating the existing data gaps, such that more degradation parameters can be assigned actual grades, thus expanding the sample size of valid HI, and capturing all possible degradation of the evaluated assets. PUC's testing, inspection, and maintenance programs are well-positioned to continue to capture this information using processes and technologies in place within the organization.

6.3.1 Distribution Data Collection Improvements

By bettering their data arrangement, PUC can refine their data collection. This can be exemplified in data with relation to Submersible Transformers; GIS data and inspection data are currently not coordinated, therefore was no way to connect the two sets of data. There is also a need to improve collection and validation of asset nameplate information across PUC

6.3.2 Station Data Collection Improvements

To have a better knowledge of the state of the stations' assets, it is recommended PUC incorporate more extensive visual inspection records into their monthly station reports. Some nameplate data requires verification for substation assets – in particular, station riser cables.

The current study did not assess the ground grids, communication, and P&C equipment. Communications and P&C equipment should be assessed for obsolescence, whereas the substation ground grid integrity and impedance should be verified with testing.

6.3.3 Transmission Line Condition Assessment

This ACA did not cover the transmission line poles, fittings, hardware, and insulators that PUC owns at operates at 115 kV. A separate assessment should be conducted to assess the condition of the transmission lines.

Appendix A – METSCO Company Profile

METSCO Energy Solutions Inc. is a Canadian corporation which started its operations on the market in 2006. METSCO is engaged in the business of providing consulting and project management services to electricity generating, transmission, and distribution companies, major industrial and commercial users of electricity, as well as municipalities and constructors on lighting services, asset management, and construction audits. Our head office is located in Toronto, ON and our western office is located in Calgary, AB. Through our network of associates, we provide consulting services to power sector clients around the world. A small subset of our major clients is shown in the figure below.

Figure A-0-1: METSCO Clients

METSCO has been leading the industry in Asset Condition Assessment and Asset Management practices for over ten years. Our founders are the pioneers of the first Health

Index methodology for power equipment in North America as well as the most robust risk-based analytics on the market today for high-voltage assets. METSCO has since completed hundreds of asset condition assessments, asset management plans, and asset management framework implementations. Our collective record of experience in these areas is the largest in the world, with ours being the only practice with widespread acceptance across regulatory jurisdictions. METSCO has worked with over 100 different utilities through its tenure, and as such, has been exposed and introduced to practices and unique challenges from a variety of entities, environments, and geographies. When a client chooses METSCO to work on improving Asset Management practices, it is choosing the industry-leading standard, rigorously tested and refined on a continued basis. Our experts have developed, supported, managed, led and sat on stand defending their own DSPs as utility staff giving METSCO the qualified expertise to provide its service to PUC.

In addition to our work in the area of asset health assessments and lifecycle enhancement, our services span a broad common utility issue area, including planning and asset management, design, construction supervision, project management, commissioning, troubleshooting operating problems, investigating asset failures and providing training and technology transfer.

Our founders and leaders are pioneers in their respective fields. The fundamental electrical utility-grade engineering services we provide include:

- Power sector process engineering and improvement
- Fixed Asset Investment Planning – development of economic investment plans
- Regulatory Proceeding Support
- Power System Planning and Studies – identifying system constraints
- Smart Grid Development – from planning to implementation of leading technologies
- Asset Performance and Asset Management
- Distribution and Transmission System Design
- Mentoring, Training, and Technical Resource Development
- Health Index Validation and Development
- Business Case Development
- Owners Engineering Services
- Risk Modeling – Asset Lifecycle and Risk Assessment

APPENDIX D

Overhead Expense

Board Appendix 2

Appendix 2-D
Overhead Expense

Applicants are to provide a breakdown of OM&A before capitalization in the below table. OM&A before capitalization may be broken down by cost center, program, drivers or another format best suited to focus on capitalized vs. uncapitalized OM&A.

OM&A Before Capitalization	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Bridge Year	2023 Test Year
	$ 12,999,598	$ 13,018,918	$ 12,964,547	$ 13,843,537	$ 14,597,914	$ 16,035,026
Total OM&A Before Capitalization (B)	$ 12,999,598	$ 13,018,918	$ 12,964,547	$ 13,843,537	$ 14,597,914	$ 16,035,026

Applicants are to provide a breakdown of capitalized OM&A in the below table. Capitalized OM&A may be broken down using the categories listed in the table below if possible. Otherwise, applicants are to provide its own break down of capitalized OM&A.

Capitalized OM&A	2018 Historical Year	2019 Historical Year	2020 Historical Year	2021 Historical Year	2022 Bridge Year	2023 Test Year	Directly Attributable? (Yes/No)	Explanation for Any Change in Treatment of Capitalized Overhead
Materials	$ 279,442	$ 269,319	$ 285,879	$ 361,731	$ 315,717	$ 322,032	Yes	
Engineering	$ 400,223	$ 499,945	$ 524,173	$ 472,489	$ 904,430	$ 952,049	Yes	
Trucking	$ 426,211	$ 437,547	$ 341,102	$ 351,519	$ 437,981	$ 495,152	Yes	
Supervisory	$ 295,199	$ 341,910	$ 342,291	$ 285,571	$ 414,533	$ 319,596	Yes	
Total Capitalized OM&A (A)	$ 1,401,075	$ 1,548,723	$ 1,493,445	$ 1,471,310	$ 2,072,661	$ 2,088,829		
% of Capitalized OM&A (=A/B)	11%	12%	12%	11%	14%	13%		

APPENDIX E

Renewable Generation Connection Investment Summary

Board Appendix 2-FA

Appendix 2-FA
Renewable Generation Connection Investment Summary (past investments or over the future rate setting period)

Enter the details of the Renewable Generation Connection projects as described in the appropriate section of the Filing Requirements.
All costs entered on this page will be transferred to the appropriate cells in the appendices that follow.
For Part A, Renewable Enabling Improvements (REI), these amounts will be transferred to Appendix 2 - FB
For Part B, Expansions, these amounts will be transferred to Appendix 2 - FC

If there are more than **five** projects proposed to be in-service in a certain year, please amend the tables below and ensure that the formulae for the Total Amounts in any given rate year are updated.
Based on the current methodology and allocation, amounts allocated represent 6% for REI Connection Investments and 17% for Expansion Investments. (EB-2009-0349, 6-10-2010, p. 15, note 9)
Ensure that OM&A costs below are not included in Recoverable OM&A (App. 2-JA)
There are two scenarios described below. Separate sets of spreadsheets (2-FA, 2-FB, 2-FC) should be submited for each scenario as required.

Scenario 1: Past Investments with No Recovery. The distributor has made investments in the past (during the IRM Years), but has not received approval for these projects and therefore did not receive revenue from the IESO under Regulation 330/09 and did not receive ratepayer revenue for the direct benefit portion of the investment.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's last Cost of Service approval.
The Direct Benefit portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the distributor's ratepayers through a rate rider.
The Provincial Recovery portion of the calculated Revenue Requirement for each year should be summed and can be applied for recovery from the IESO through a separate order.

Scenario 2: Investments in the Test Year and Beyond. Distributor plans to make investments in the Test Year and/or beyond. These investments should be added to 2-FA in the appropriate year.
The WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage should correspond to the distributor's current application.

Part A

						Test Year				
REI Investments (Direct Benefit at 6%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Project 1										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5										
Name: REI Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Incremental OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Incremental OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

Part B

						Test Year				
Expansion Investments (Direct Benefit at 17%)	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Project 1										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 2										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 3										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 4										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Project 5										
Name: Expansion Connection Project										
Capital Costs	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Start-Up)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Incremental OM&A (Ongoing)	$0	$0	$0	$0	$0	$0	$0	$0	$0	$0
Total Capital Costs	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Incremental OM&A (Start-Up)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**
Total Incremental OM&A (Ongoing)	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**	**$ -**

APPENDIX F

Calculation of Renewable Generation Connection Direct Benefits: Improvements

Board Appendix 2-FB

Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments entered in Part A of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables that were approved in your last cost of service test year. For test year and beyond, enter variables as in the application.
Rate Riders related to the direct benefit portion of the renewable investments are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

PUC Distribution Inc.2018			2018			2019			2020			2021			2022			Test Year 2023			2024		
			Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%	Total	Direct Benefit 6%	Provincial 94%
Net Fixed Assets (average)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Incremental OM&A (start-up, applicable for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**																					
Allowance for Working Capital (enter rate)	7.50%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**																					
Deemed ST Debt	4.00%	4.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56.00%	56.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40.00%	40.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest (enter rate)				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest (enter rate)				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Return on Equity (enter rate)	9.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection					$ -			$ -			$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO					$ -			$ -			$ -			$ -			$ -			$ -			$ -

Appendix 2-FB

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Enabling Improvement Investments

This table will calculate the distributor/provincial shares of the investments enter
Enter values in green shaded cells: WCA percentage, debt percentages, interest ra
For historical investments, enter these variables that were approved in your last cost of service test year. For test year and beyond, enter variables as in the application.
Rate Riders related to the direct benefit portion of the renewable investments are

PUC Distribution Inc.2018			2025			2026			2027			2028		
				Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
			Total	6%	94%	Total	6%	94%	Total	6%	94%	Total	6%	94%
Net Fixed Assets (average)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Incremental OM&A (start-up, applicable for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**												
Allowance for Working Capital (enter rate)	7.50%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**												
Deemed ST Debt	4.00%	4.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56.00%	56.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40.00%	40.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest (enter rate)				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest (enter rate)				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Return on Equity (enter rate)	9.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection					$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO					$ -			$ -			$ -			$ -

APPENDIX G

Calculation of Renewable Generation Connection Direct Benefits: Expansion

Board Appendix 2-FC

Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables that were approved in your last cost of service test year. For test year and beyond, enter variables as in the application.
Rate Riders related to the direct benefit portion of the renewable investments are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

			2018			2019			2020			2021			2022			Test Year 2023		
			Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%	Total	Direct Benefit 17%	Provincial 83%
Net Fixed Assets (average)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Incremental OM&A (start-up, applicable for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**																		
Allowance for Working Capital (enter rate)	7.50%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	2018	**2023**																		
Deemed ST Debt	4.00%	4.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56.00%	56.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40.00%	40.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest (enter rate)	0.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest (enter rate)	0.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Return on Equity (enter rate)	9.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection					$ -			$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO					$ -			$ -			$ -			$ -			$ -			$ -

Appendix 2-FC

Calculation of Renewable Generation Connection Direct Benefits/Provincial Amount: Renewable Expansion Investments

This table will calculate the distributor/provincial shares of the investments entered in Part B of Appendix 2-FA.
Enter values in green shaded cells: WCA percentage, debt percentages, interest rates, kWh, tax rates, amortization period, CCA Class and percentage.
For historical investments, enter these variables that were approved in your last cost of service test year. For test year and beyond, enter variables as in the application.
Rate Riders related to the direct benefit portion of the renewable investments are not calculated for the Test Year as these assets and costs are already in the distributor's rate base/revenue requirement.

			2024			2025			2026			2027			2028		
				Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial		Direct Benefit	Provincial
			Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%	Total	17%	83%
Net Fixed Assets (average)			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Incremental OM&A (on-going, N/A for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Incremental OM&A (start-up, applicable for Provincial Recovery)			$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -	$0	$ -	$ -
Rebasing Year vs. Test Year	**2018**	**2023**															
Allowance for Working Capital (enter rate)	7.50%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Rate Base				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
	2018	**2023**															
Deemed ST Debt	4.00%	4.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed LT Debt	56.00%	56.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Deemed Equity	40.00%	40.00%		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
ST Interest (enter rate)	0.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
LT Interest (enter rate)	0.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Return on Equity (enter rate)	9.00%			$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Cost of Capital Total				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
OM&A				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Amortization			$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Grossed-up PILs				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Revenue Requirement				$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -		$ -	$ -
Provincial Rate Protection					$ -			$ -			$ -			$ -			$ -
Monthly Amount Paid by IESO					$ -			$ -			$ -			$ -			$ -

EXHIBIT 3
OPERATING REVENUE

TABLE OF CONTENTS

LIST OF TABLES

EXHIBIT 3: OPERATING REVENUE

3.1 LOAD AND REVENUE FORECASTS

This Exhibit provides the details of PUC Distribution Inc.'s ("PUC") operating revenue for 2018 Board Approved, 2018 Actual, 2019 Actual, 2020 Actual, 2021 Actual, the 2022 Bridge Year ("Bridge Year") and the 2023 Test Year ("Test Year"). This Exhibit also provides a detailed variance analysis by rate classification of the operating revenue components. Distribution revenue excludes revenue from commodity sales.

PUC is proposing a total Service Revenue Requirement of $27,752,199 for the 2023 Test Year. This amount includes a Base Revenue Requirement of $25,001,934 plus Other Revenue of $2,750,265.

The following Table 3-1 summarizes PUC's total operating revenue. Revenue for each of the actual years is from PUC's audited financial statements. The Test Year is provided on the basis of both existing and proposed distribution rates. The increase from 2021 actual to 2022 Bridge Year is primarily from the addition of the ICM SSG rate rider and an increase in residential customer count from the load forecast.

Table 3-1: Summary of Operating Revenue

	2018 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge	2023 Test at Current Rates	2023 Test at Proposed Rates
Distribution Throughput Revenue								
Residential	11,226,807	9,245,370	11,506,066	11,379,210	11,736,129	12,235,062	12,276,778	15,344,319
General Service <50 kW	3,149,458	2,685,055	3,177,639	2,983,921	3,144,595	3,227,573	3,029,237	3,782,036
General Service 50 to 4,999 kW	4,544,464	4,050,004	4,525,158	4,236,302	4,267,431	4,653,086	4,478,442	5,517,875
Sentinel Lighting	34,742	30,336	34,812	35,057	36,274	35,591	34,786	43,448
Street Lighting	195,345	398,346	192,309	197,592	206,925	211,009	211,009	263,810
Unmetered Scattered Load	39,551	32,133	37,136	37,506	38,751	40,213	40,296	50,446
Total Distribution	**19,190,367**	**16,441,244**	**19,473,120**	**18,869,588**	**19,430,106**	**20,402,534**	**20,070,548**	**25,001,934**
LRAMVA		699,556	384,312	-	-			
Tax Change		(179,809)	(786,265)	(252,068)	15			
ICM Sub 16	-	-	-	-	269,820	235,047	231,297	
ICM SSG						862,560	848,733	
Foregone Revenue IRM				192,400				
Lost Revenue COVID				222,316	(222,316)			
Total	**19,190,367**	**16,960,991**	**19,071,168**	**19,032,237**	**19,477,625**	**21,432,941**	**21,083,379**	**25,001,934**
Late Payment Charges	259,000	221,084	173,679	296,114	292,124	220,000	230,292	230,292
Miscellaneous Service Revenue	170,100	193,432	161,185	128,942	203,119	152,700	155,754	155,754
Other Operating Revenues	2,216,297	2,040,128	2,271,709	2,305,283	2,335,541	2,159,422	2,235,819	2,235,819
Other Income or Deductions	132,500	713,169	97,888	166,797	(125,604)	120,000	128,400	128,400
Total	**2,777,897**	**3,167,813**	**2,704,461**	**2,897,136**	**2,705,180**	**2,652,122**	**2,750,265**	**2,750,265**
Grand Total	**21,968,264**	**20,128,804**	**21,775,628**	**21,929,373**	**22,182,805**	**24,085,063**	**22,820,813**	**27,752,199**

Summary of Load and Customer/Connection Forecast

The purpose of this evidence is to present the process used by PUC to prepare the weather normalized load and customer/connection forecast used to design the proposed 2023 distribution rates.

In summary, as a starting point, PUC used the same regression analysis methodology approved by the Ontario Energy Board in its 2018 Cost of Service application ("2018 COS") (EB-2017-0071) and updated the analysis for actual power purchases to the end of the 2021. The updated regression analysis includes the variables used in the 2018 COS but also includes a trend variable instead of a Conservation and Demand Management ("CDM") activity variable. These variables reflect the most statistically significant regression output. The regression analysis methodology used in this application has also been used by a number of distributors in more recent cost of service rate applications to determine the forecasted volume. With regards to the overall process of load forecasting, PUC believes that conducting a regression analysis on historical electricity purchases to produce an equation that will predict purchases is appropriate. PUC has the data for the amount of electricity (kWh) purchased from the IESO for use by PUC's customers. With a regression analysis, these purchases can be related to other monthly explanatory variables such as heating degree days ("HDD") and cooling degree days ("CDD") which occur in the same month. The results of the regression analysis produce an equation that predicts the purchases based on the explanatory variables. This prediction model is then used as the basis to forecast the total level of weather normalized purchases for the Bridge Year and the Test Year which is converted to billed kWh and kW, where applicable, by rate class. A detailed explanation of the process is provided later in this evidence. A live Excel file named "2023 PUC Load Forecast Model - With Regression Analysis" has also been provided.

COVID Findings in Regression Analysis

PUC completed the regression analysis using actual data as of year-end 2021. Using the variables explained above produced predicted purchases of 558,517,707 kWh for the 2023 test year. PUC noticed the customer count to be a bit abnormal in comparison to previous years when running this regression analysis. Table 3-2 shows the historical and predicted customer count prior to any COVID adjustment.

Table 3-2 Customer Count Prior to COVID Normalization

Year	Residential	General Service <50 kW	General Service 50 to 4,999 kW	Sentinel Lights	Street Lights	USL	Total
2011 (Actual)	29,124	3,366	403	402	8,846	19	42,160
2012 (Actual)	29,327	3,448	366	392	8,846	21	42,400
2013 (Actual)	29,504	3,474	373	374	8,846	21	42,592
2014 (Actual)	29,514	3,464	370	362	8,846	21	42,577
2015 (Actual)	29,566	3,431	373	360	8,839	21	42,590
2016 (Actual)	29,620	3,414	361	362	8,872	21	42,650
2017 (Actual)	29,729	3,417	361	361	8,070	21	41,959
2018 (Actual)	29,837	3,414	362	355	8,070	23	42,061
2019 (Actual)	29,897	3,388	362	350	8,037	23	42,057
2020 (Actual)	30,026	3,355	370	348	8,037	24	42,160
2021 (Actual)	30,134	3,423	308	330	8,037	24	42,256
2022 (Bridge)	30,237	3,429	305	325	8,037	25	42,357
2023 (Test)	30,340	3,435	303	320	8,037	25	42,459

Overall PUC has seen a general decline in the consumption for all rate classes over the past 10 years. However, in 2020 and 2021 PUC sees a dip in the GS<50 and GS>50 consumption which is believed to be related to the COVID-19 pandemic. Table 3-3 below shows this historical consumption along with the variance in consumption for the two general service classes.

Table 3-3: Historical Consumption GS

Year	General Service <50 kW	Variance/ Trend	Rolling 5 year Average	General Service 50 to 4,999 kW	Variance/ Trend	Rolling 5 year Average
2011	101,728,299			255,968,368		
2012	97,479,014	(4.2%)		254,314,087	(0.6%)	
2013	95,827,695	(1.7%)		259,048,750	1.9%	
2014	99,153,426	3.5%		258,807,830	(0.1%)	
2015	95,701,162	(3.5%)		254,784,565	(1.6%)	
2016	92,174,996	(3.7%)	(1.9%)	249,955,178	(1.9%)	(0.5%)
2017	91,035,995	(1.2%)	(1.3%)	245,166,376	(1.9%)	(0.7%)
2018	92,759,999	1.9%	(0.6%)	241,817,729	(1.4%)	(1.4%)
2019	91,718,380	(1.1%)	(1.5%)	240,708,316	(0.5%)	(1.4%)
2020	84,774,528	(7.6%)		227,128,751	(5.6%)	
2021	88,569,433	4.5%		219,715,371	(3.3%)	

Table 3-3 shows the rolling 5-year average for the GS<50 rate class ranges from (0.6%) to (1.9%) and for the GS>50 from (0.5%) to (1.4%). 2020 and 2021 are two abnormal years in terms of consumption variance which hasn't followed the historical trend for PUC. PUC's growth has been relatively stagnant over the last 10 years. PUC believes that these outliers are related to the COVID-19 pandemic. Additionally in Table 3-4 below, there are fluctuations in customer count for 2020 and 2021 for these rate classes.

Table 3-4: General Service Customer Count

Year	General Service <50 kW	Variance/ Trend	Rolling 5 year Average	General Service 50 to 4,999 kW	Variance/ Trend	Rolling 5 year Average
2011	3,366			403		
2012	3,448	2.4%		366	(9.2%)	
2013	3,474	0.8%		373	1.9%	
2014	3,464	(0.3%)		370	(0.8%)	
2015	3,431	(1.0%)		373	0.8%	
2016	3,414	(0.5%)	0.3%	361	(3.2%)	(2.1%)
2017	3,417	0.1%	(0.2%)	361	0.0%	(0.3%)
2018	3,414	(0.1%)	(0.3%)	362	0.3%	(0.6%)
2019	3,388	(0.8%)	(0.4%)	362	0.0%	(0.4%)
2020	3,355	(1.0%)		370	2.2%	
2021	3,423	2.0%		308	(16.8%)	

The most important piece to note here is PUC sees a drop of 16.8% of its GS>50 customers in 2021. PUC reviews the consumption of the GS<50 and GS>50 rate classes in the fall of each year to determine if any customers are required to shift classes based on their consumption. Once PUC analyzed the GS>50 consumption of each customer in the fall of 2020, almost all customers from that 16.8% drop shifted to the GS<50 class – the GS>50 saw a drop of 62 customers and GS<50 saw an increase of 68 customers. However, over time these customers should start to see a return to pre pandemic levels of consumption.

In order to predict the number of customers for the 2023 test year, PUC uses a 10-year geomean and applies this geomean to the last year of actual customer count. Since PUC, saw an abnormal drop in number of customers from GS>50 and traced those customers to the GS<50, it was determined that some kind of adjustment was needed.

Given these findings, PUC has normalized its actual consumption used for 2020 and 2021 for the GS<50 and GS>50 rate classes. PUC used the 2012 to 2019 average change in consumption, presented in Table 3-5, and average change in customer count, presented in Table 3-6, to normalize both consumption and customer count.

Table 3-5: Normalized Small and Large General Service Consumption

Year	General Service <50 kW	Variance/ Trend	Rolling 5 year Average	General Service 50 to 4,999 kW	Variance/ Trend	Rolling 5 year Average
2011	101,728,299			255,968,368		
2012	97,479,014	(4.2%)		254,314,087	(0.6%)	
2013	95,827,695	(1.7%)		259,048,750	1.9%	
2014	99,153,426	3.5%		258,807,830	(0.1%)	
2015	95,701,162	(3.5%)		254,784,565	(1.6%)	
2016	92,174,996	(3.7%)	(1.9%)	249,955,178	(1.9%)	(0.5%)
2017	91,035,995	(1.2%)	(1.3%)	245,166,376	(1.9%)	(0.7%)
2018	92,759,999	1.9%	(0.6%)	241,817,729	(1.4%)	(1.4%)
2019	91,718,380	(1.1%)	(1.5%)	240,708,316	(0.5%)	(1.4%)
2020	84,774,528	(7.6%)		227,128,751	(5.6%)	
2021	88,569,433	4.5%		219,715,371	(3.3%)	
2012-2019 average		(1.3%)			(0.8%)	
2020 normalized	90,568,262			238,882,521		
2021 normalized	89,432,566			237,070,574		

Table 3-6: Normalized Small and Large General Service Customer Count

Year	General Service <50 kW	Variance/ Trend	Rolling 5 year Average	General Service 50 to 4,999 kW	Variance/ Trend	Rolling 5 year Average
2011	3,366			403		
2012	3,448	2.4%		366	(9.2%)	
2013	3,474	0.8%		373	1.9%	
2014	3,464	(0.3%)		370	(0.8%)	
2015	3,431	(1.0%)		373	0.8%	
2016	3,414	(0.5%)	0.3%	361	(3.2%)	(2.1%)
2017	3,417	0.1%	(0.2%)	361	0.0%	(0.3%)
2018	3,414	(0.1%)	(0.3%)	362	0.3%	(0.6%)
2019	3,388	(0.8%)	(0.4%)	362	0.0%	(0.4%)
2020	3,355	(1.0%)		370	2.2%	
2021	3,423	2.0%		308	(16.8%)	
2012-2019 Average		0.1%			(1.3%)	
2020 Normalized	3,391			357		
2021 Normalized	3,394			353		

Incorporating these changes into each general service rate classes resulted in the following consumption changes shown in Table 3-7 below for 2020 and 2021.

Table 3-7: Summary of Consumption Changes for General Service Rate Classes

	GS<50	GS>50	Total
2020 Actual	84,774,528	227,128,751	
Adjustment	5,793,735	11,753,769	17,547,504
2020 Normalized	90,568,262	238,882,521	
2021 Actual	88,569,433	219,715,371	
Adjustment	863,133	17,355,203	18,218,336
2021 Normalized	89,432,566	237,070,574	

PUC had to consider this adjustment in its overall purchased power for the each year before running the regression analysis again. The result is an adjustment to metered consumption in 2020 of 17,54,504 kWh and an adjustment in 2021 of 18,218,336 kWh. Once this adjustment is added to the actual yearly consumption to get a "COVID normalized" yearly consumption, its then grossed up for the loss factor. This results in normalized yearly purchases which will be used in the power purchased model regression analysis presented in section 2.1.3.1. Table 3-8 below summarizes this.

Table 3-8: Normalized Yearly Purchases

Year	Change in Total Consumption	Actual Yearly Consumption	Normalized Yearly Consumption	Yearly Loss Facotr	Normalized Yearly Purchass
2020	17,547,504	613,632,199	631,179,703	1.044	659,068,596
2021	18,218,336	604,318,512	622,536,848	1.040	647,740,937

PUC then applied the increase in consumption from normalized purchases evenly across each month. For 2020, an increase of 18,322,847 kWh results in a monthly adjustment of 1,526,904 kWh and in 2021, an increase of 18,955,925 kWh results in a monthly adjustment of 1,579,660 kWh.

PUC also incorporated the normalized customer count from Table 3-6 above. This resulted in the change to the yearly customer total as show in Table 3-9.

Table 3-9: Change in General Service Customer Count

	GS<50	GS>50	Total
2020 Actual	3,355	370	
Adjustment	36	(13)	23
2020 Normalized	3,391	357	
2021 Actual	3,423	308	
Adjustment	(29)	45	16
2021 Normalized	3,394	353	

Therefore, 23 customers were added to the 2020 total count and 16 customers to the 2021 total count. Table 3-10 shows the revised total of 33,798 customers for 2020 and 33,905 customers for 2021.

Table 3-10: Normalized Customer Count

Year	Change in Total Customers	Actual Yearly Customer Count	Normalized Yearly Customer Count
2020	23	33,775	33,798
2021	16	33,889	33,905

Once the purchased kWh and number of customers were normalized in 2020 and 2021, PUC ran the regression model again. The following Table 3-11 compares the results of the regression before and after COVID-19 normalization.

Table 3-11: Comparison of Regression Analysis

Year	2023 Regression Actual	2023 Regression Normalized for COVID	Variance
2020	558,517,707	578,772,961	20,255,254
2021	42,460	42,463	3

PUC submits the load forecasting methodology is reasonable for the purposes of this Application. PUC submits that this load forecast is a better representation of what is likely to occur in its community by applying the COVID normalization explained above.

The following provides the material to support the COVID and weather normalized load forecast used by PUC in this Application. All numbers presented in 2020 and 2021 have been normalized for COVID.

Table 3-12, Table 3-13, Table 3-14 and Table 3-15 below provide a summary of the COVID and weather normalized load and customer/connection forecast used in this Application.

Table 3-12: Summary of Load and Customer/ Connection Forecast (2020 and 2021 COVID Normalized)

Year	Billed Actual (GWh)	Growth (GWh)	Billed Weather Normal (GWh)	Growth (GWh)	Customer/ Connection Count	Growth
Billed Energy (GWh) and Customer Count / Connections						
2018 Board Approved			628.9		42,050	
2008	710.7	8.9	701.0	2.7	41,729	191
2009	707.8	(2.9)	698.6	(2.4)	41,995	266
2010	683.8	(24.0)	691.4	(7.3)	42,110	115
2011	711.9	28.2	715.0	23.6	42,160	50
2012	676.8	(35.2)	696.8	(18.2)	42,400	240
2013	688.2	11.5	676.7	(20.1)	42,592	192
2014	701.8	13.6	682.9	6.3	42,577	(15)
2015	669.4	(32.5)	661.9	(21.0)	42,590	13
2016	636.9	(32.5)	645.7	(16.2)	42,650	60
2017	622.5	(14.3)	631.5	(14.3)	41,959	(691)
2018	633.7	11.2	618.3	(13.1)	42,061	102
2019	631.9	(1.8)	619.5	1.2	42,057	(4)
2020	631.2	(0.8)	632.2	12.7	42,183	126
2021	622.5	(8.6)	651.1	18.9	42,272	89
2022 Bridge			602.7	(48.4)	42,367	95
2023 Test			578.8	(23.9)	42,463	96

In the above Table 3-12, the billed GWh data from 2008 to 2021 reflects actual weather and weather normal conditions in each year. In 2017, there is a slightly abnormal dip in customer count as a result of shifting from ‘number of devices’ to ‘number of connections’ for the Street Light class, as outlined in PUC’s 2018 COS (EB-2017-0071, Ex 3 pg. 6 of 51). The weather normal values are the actual values adjusted by the weather normal conversion factor outlined in Table 3-13. The weather conversion factor is determined consistent with the approach outlined by the Board in Appendix 2-IA. For 2022 and 2023, the forecasted billed GWh is on a weather normal basis.

Customer/Connection values are on an average basis and street lights and sentinel lights are measured as connections. PUC has continued to use number of connections for measuring Streetlights since its 2018 COS application (EB-2017-0071).

On a rate class basis, the actual and forecasted billed amounts are shown in Table 3-14. Actual volumes have been weather normalized by rate class using the weather normal conversion factor from Table 3-15. The actual and forecasted number of customers/connections is shown in Table 3-14. The customer/connection usage on an actual and weather normal basis is shown in Table 3-15.

Table 3-13: Billed GWh by Rate Class (2020 and 2021 COVID Normalized)

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
Billed Energy (GWh) - Actual							
2008	347.4	93.5	261.1	0.3	7.6	0.8	710.7
2009	348.6	91.5	259.0	0.3	7.6	0.8	707.8
2010	326.5	91.4	257.0	0.3	7.8	0.8	683.8
2011	345.3	101.7	256.0	0.3	7.8	0.9	711.9
2012	316.1	97.5	254.3	0.2	7.7	0.9	676.8
2013	324.2	95.8	259.0	0.2	8.1	0.9	688.2
2014	335.0	99.2	258.8	0.2	7.8	0.9	701.8
2015	310.5	95.7	254.8	0.2	7.3	0.9	669.4
2016	288.7	92.2	250.0	0.2	4.9	0.9	636.9
2017	282.8	91.0	245.2	0.2	2.4	0.9	622.5
2018	295.6	92.8	241.8	0.2	2.4	0.9	633.7
2019	296.0	91.7	240.7	0.2	2.4	0.9	631.9
2020	298.2	90.6	238.9	0.2	2.5	0.9	631.2
2021	292.5	89.4	237.1	0.2	2.5	0.9	622.5
Billed Energy (GWh) - Weather Normal							
2008	340.4	91.6	255.9	0.3	7.5	0.8	696.4
2009	341.6	89.6	253.8	0.3	7.5	0.8	693.6
2010	319.9	89.5	251.9	0.3	7.6	0.8	670.0
2011	338.4	99.7	250.8	0.3	7.7	0.9	697.6
2012	309.8	95.5	249.2	0.2	7.6	0.8	663.2
2013	317.7	93.9	253.9	0.2	7.9	0.8	674.4
2014	328.2	97.2	253.6	0.2	7.7	0.9	687.8
2015	304.2	93.8	249.7	0.2	7.1	0.9	656.0
2016	283.0	90.3	244.9	0.2	4.8	0.9	624.1
2017	277.1	89.2	240.2	0.2	2.4	0.9	610.1
2018	289.7	90.9	237.0	0.2	2.4	0.9	621.0
2019	290.1	89.9	235.9	0.2	2.4	0.8	619.3
2020	292.2	88.8	234.1	0.2	2.4	0.9	618.5
2021	286.6	87.6	232.3	0.2	2.4	0.9	610.0

Table 3-14: Number of Customers/ Connections (2020 and 2021 COVID Normalized)

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
2008	28,780	3,325	426	435	8,741	22	41,729
2009	28,971	3,352	433	423	8,799	17	41,995
2010	29,057	3,345	435	411	8,846	16	42,110
2011	29,124	3,366	403	402	8,846	19	42,160
2012	29,327	3,448	366	392	8,846	21	42,400
2013	29,504	3,474	373	374	8,846	21	42,592
2014	29,514	3,464	370	362	8,846	21	42,577
2014	29,566	3,431	373	360	8,839	21	42,590
2015	29,620	3,414	361	362	8,872	21	42,650
2016	29,729	3,417	361	361	8,070	21	41,959
2017	29,837	3,414	362	355	8,070	23	42,061
2018	29,897	3,388	362	350	8,037	23	42,057
2019	30,026	3,391	357	348	8,037	24	42,183
2020	30,134	3,394	353	330	8,037	24	42,272
2021	30,237	3,397	348	324	8,037	25	42,367

Table 3-15: Annual Usage by Rate Class 2020 and 2021 COVID Normalized)

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load
Actual Annual Energy Usage per Customer/Connection (kWh per customer/connection)						
2008	12,070	28,113	612,967	618	872	38,560
2009	12,033	27,282	598,148	621	864	48,438
2010	11,236	27,318	590,889	628	877	52,327
2011	11,856	30,222	635,157	648	883	46,046
2012	10,779	28,271	694,847	629	875	41,047
2013	10,988	27,584	694,501	635	914	40,830
2014	11,329	28,899	693,855	676	884	41,715
2015	10,481	28,032	705,774	650	822	43,462
2016	9,713	26,975	692,397	629	603	43,012
2017	9,479	26,665	677,255	602	297	39,466
2018	9,888	27,379	668,005	597	298	38,922
2019	9,859	27,048	674,253	594	300	36,103
2020	9,895	26,685	676,721	619	307	36,284
2021	9,673	26,328	680,544	629	306	35,735
Normalized Annual Energy Usage per Customer/Connection (kWh per customer/connection)						
2008	11,827	27,549	600,671	605	854	37,787
2009	11,792	26,735	586,149	608	847	47,466
2010	11,011	26,770	579,036	615	859	51,277
2011	11,618	29,616	622,416	635	866	45,122
2012	10,563	27,704	680,908	616	857	40,224
2013	10,767	27,031	680,569	622	896	40,011
2014	11,121	28,050	685,449	659	865	40,879
2015	10,290	27,334	669,366	640	809	42,590
2016	9,553	26,458	678,507	615	538	42,149
2017	9,322	26,108	665,508	580	291	42,357
2018	9,709	26,625	654,604	577	291	38,142
2019	9,703	26,528	651,601	579	294	36,917
2020	9,732	26,173	655,715	575	301	35,556
2021	9,512	25,822	658,116	605	300	35,846

3.1.2 Multivariate Regression Model

PUC's weather normalized load forecast is developed in a four-step process. First, the 2020 and 2021 actual purchases and customer count were normalized to adjust for those years being affected by COVID-19. Second, a total system weather normalized purchased power forecast is developed based on a regression analysis that incorporates variables that impact PUC usage. Third, the weather normalized purchased power forecast is adjusted by a historical loss factor to produce a weather normalized billed forecast. Finally, the forecast of billed energy by rate class is developed based on a forecast of customer numbers and historical usage patterns per customer. For the rate classes that have weather sensitive load, their forecasted billed energy is adjusted to ensure that the total billed energy forecast by rate class is equivalent to the total weather normalized billed energy forecast. The forecast of customers by rate class was determined using a 10-year geometric mean analysis. The forecast also contains a manual adjustment for expected CDM results. For those rate classes that use kW as the distribution volumetric billing determinant, an adjustment factor is applied to the class energy forecast based on the historical relationship between kW and kWh. The following will explain the forecasting process in more detail.

<u>Purchased KWh Load Forecast</u>

An equation to predict total system purchased energy is developed using a multivariate regression model with independent variables outlined below. The regression model uses monthly kWh and monthly values of independent variables from January 2011 to December 2021 to determine the monthly regression coefficients. This provides 132 monthly data points which are a reasonable data set for use in a multiple regression analysis.

With regards to weather normalization, PUC submits that it is appropriate to review the impact of weather over the past ten years January 2012 to December 2021 since it is consistent with the time period for weather normalization outlined in the filing requirements. It is also reflective of more recent weather conditions. The average weather conditions over this period are applied in the prediction formula to determine a weather normalized forecast.

The multivariate regression model has determined the drivers of year-over-year changes in PUC's load growth are weather (HDD and CDD), calendar variables (days in month and seasonal flag), number of customers and a trend variable. These factors are captured within the multivariate regression model.

Weather impacts on load are apparent in both the winter heating season and in the summer cooling season. For that reason, both HDD (i.e. a measure of coldness in winter) and CDD (i.e. a measure of summer heat) are modeled.

Other factors determining energy use in the monthly model are the number of days in a particular month and a flag that indicates spring and fall months.

The regression analysis also indicates that the number of customers and a trend variable are significant contributors to the total energy used in the PUC service area.

The following outlines the predication model used by PUC to predict weather normal purchases for 2022 and 2023.

PUC Distribution Monthly Predicted kWh Purchases

= Constant of (2,885,688)

+ Heating Degree Days * 35,098

+ Cooling Degree Days * 122,990

+ Spring Fall Flag * (2,820,823)

+ Number of Days in the Month * 1,715,046

+ Number of Customers * (43)

+ Trend Variable (65,955)

The monthly data used in the regression model and the resulting monthly prediction for the actual and forecasted years are provided in Appendix A.

The sources of data for the various data points are:

- Environment Canada's website provided the monthly HDD and CDD information. Weather data from the Sault Ste. Marie Weather Station was used. 18° C is the base number from which HDD and CDD are measured.
- Annual calendars provide information related to number of days in the month and the months defined to be spring or fall (i.e. March to May and September to November).
- PUC's billing system provided the customer data.
- The trend variable is used to capture the general direction of consumption over time that cannot be explained or is directly observable. For PUC, this variable appears to be capturing the declining consumption overall.

Table 3-16: Statistical Results

R Square	95.8%
Adjusted R Square	95.6%
F Test	476.0
MAPE (Monthly)	0.0%
T-stats by Coefficient	
Heating Degree Days	40.7
Cooling Degree Days	7.5
Spring Fall Flag	(6.8)
Number of Days in Month	7.6
Trend	(3.9)
Number of Customers	(1.6)
Constant	1.5

The annual results of the above prediction formula compared to the actual annual purchases from 2011 to 2021 are shown below in Table 3-17 along with the predicted total system purchases for PUC for 2022 and 2023 on a weather normal basis. In addition, weather normal values for 2023 are provided on a 20-year trend assumption for weather normalization. Information is also provided to show the Weather Normal Conversion Factor which is used to weather normalize actual volume data. In Table 3-17, the Predicted Weather Normal values are similar to the Predicted amounts, but the weather normalized HDD and CDD used to determine the weather normal forecast for 2022 and 2023 are used in the prediction formula in place of actual HDD and CDD. The ratio of Predicted Weather Normal to Predicted Values results in a Weather Normal Conversion Factor. This factor is applied to the actual amount which results in the Actual Weather Normal value.

Table 3-17: Total System Purchase (2020 and 2021 COVID Normalized)

Year	Actual	Predicted	% Difference	Predicted Weather Normal	Weather Normal Conversion Factor	Actual Weather Normal
Purchased Energy (GWh)						
2011	745.0	731.1	(1.9%)	734.2	1.0043	748.2
2012	707.0	705.5	(0.2%)	726.4	1.0296	727.9
2013	730.6	727.3	(0.5%)	715.0	0.9832	718.3
2014	730.5	725.1	(0.7%)	705.5	0.9731	710.8
2015	698.5	703.9	0.8%	696.0	0.9888	690.7
2016	670.0	678.8	1.3%	688.2	1.0139	679.2
2017	653.0	667.4	2.2%	677.0	1.0143	662.3
2018	666.7	684.0	2.6%	667.4	0.9757	650.6
2019	660.6	671.1	1.6%	657.9	0.9804	647.7
2020	659.1	647.3	(1.8%)	648.3	1.0016	660.1
2021	647.7	610.8	(5.7%)	638.8	1.0459	677.5
2022 Bridge		630.5		629.2	0.9980	
2023 Test		620.9		619.7	0.9980	
2023 - 20 year trend		594.0		594.0	1.0000	

The weather normalized amount for 2023 is determined by using 2023 dependent variables in the prediction formula on a monthly basis along with the average monthly HDD and CDD which have occurred from January 2011 to December 2021. The 2023 weather normal 20-year trend value reflects the trend in monthly HDD and CDD which have occurred from January 2002 to December 2021.

Billed KWh Load Forecast

To determine the total weather normalized energy billed forecast, the total system weather normalized purchases forecast is adjusted by a historical loss factor. The historical loss factor used is 4.62% which represents the average loss factor from 2017 to 2021. With this average loss factor the total weather normalized billed energy before the adjustment discussed below will be 602.7 (GWh) for 2022 (i.e. 630.5/1.0462) and 593.5 (GWh) for 2023 (i.e. (i.e. 621.0/1.0462).

Billed KWh Load Forecast and Customer/Connection Forecast by Rate Class

Since the total weather normalized billed PUC Distribution amount is known, this amount needs to be distributed by rate class for rate design purposes taking into consideration the customer/connection forecast and expected usage per customer by rate class.

The next step in the forecasting process is to determine a customer/connection forecast. The customer/connection forecast is based on reviewing historical customer/connection data that is available as shown in the following Table 3-18.

Table 3-18: Historical Customer/Connection Data (2020 and 2021 COVID Normalized)

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
Number of Customers/Connections							
2008	28,780	3,325	426	435	8,741	22	41,729
2009	28,971	3,352	433	423	8,799	17	41,995
2010	29,057	3,345	435	411	8,846	16	42,110
2011	29,124	3,366	403	402	8,846	19	42,160
2012	29,327	3,448	366	392	8,846	21	42,400
2013	29,504	3,474	373	374	8,846	21	42,592
2014	29,514	3,464	370	362	8,846	21	42,577
2015	29,566	3,431	373	360	8,839	21	42,590
2016	29,620	3,414	361	362	8,872	21	42,650
2017	29,729	3,417	361	361	8,070	21	41,959
2018	29,837	3,414	362	355	8,070	23	42,061
2019	29,897	3,388	362	350	8,037	23	42,057
2020	30,026	3,391	357	348	8,037	24	42,183
2021	30,134	3,394	353	330	8,037	24	42,272

From the historical customer/connection data the growth rate in customer/connection can be evaluated which is provided on the following Table 3-19.

Table 3-19: Growth Rate in Customer/Connections
(2020 and 2021 COVID Normalized)

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load
Growth Rate in Customers/Connections						
2012	0.7%	2.4%	(9.2%)	(2.5%)	0.0%	10.5%
2013	0.6%	0.8%	1.9%	(4.6%)	0.0%	0.0%
2014	0.0%	(0.3%)	(0.8%)	(3.2%)	0.0%	0.0%
2015	0.2%	(1.0%)	0.8%	(0.6%)	(0.1%)	0.0%
2016	0.2%	(0.5%)	(3.2%)	0.6%	0.4%	0.0%
2017	0.4%	0.1%	0.0%	(0.3%)	(9.0%)	0.0%
2018	0.4%	(0.1%)	0.3%	(1.7%)	0.0%	9.5%
2019	0.2%	(0.8%)	0.0%	(1.4%)	(0.4%)	0.0%
2020	0.4%	0.1%	(1.4%)	(0.6%)	0.0%	4.3%
2021	0.4%	0.1%	(1.1%)	(5.2%)	0.0%	0.0%
Geometric Mean	0.3%	0.1%	(1.3%)	(2.0%)	0.0%	2.4%

The geometric mean was determined for each rate class to reflect the average growth rate from 2012 to 2021.

The geometric mean analysis was used to forecast the number of customers/connections for 2022 and 2023. The results of the geometric mean analysis were applied to the 2021 customer/connection value to determine the 2022 customer/connection forecast. The 2023 customer/connection forecast is determined by applying the geometric mean factor to the 2022 forecast. Table 3-20 outlines the forecast of customers/connections by rate class.

Table 3-20: Customer/Connection Forecast
(2020 and 2021 COVID Normalized)

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
Forecast Number of Customers/Connections							
2022	30,237	3,397	348	324	8,037	25	42,367
2023	30,340	3,400	344	317	8,037	25	42,463

The next step in the process is to review the historical customer/connection usage and to reflect this usage per customer in the forecast. Table 3-21 below provides the average annual usage per customer by rate class for 2021.

Table 3-21: 2021 Actual Annual Usage per Customer (2020 and 2021 COVID Normalized)

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load
Annual kWh Usage Per Customer/Connection						
2021	9,706	26,350	671,588	617	306	708,568

The geomean from 2011 to 2021 was used to forecast 2022 and 2023 usage per customer/connection except for the Street Light class. The Street Light class forecast was held constant using a geomean of 1.0. The resulting usage forecast is as follows in Table 3-22.

Table 3-22: Forecast Annual kWh Usage per Customer/Connection (2020 and 2021 COVID Normalized)

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load
Forecast Annual kWh Usage per Customers/Connection						
2022	9,514	25,991	675,344	614	306	35,748
2023	9,326	25,637	679,121	611	306	34,934

The preceding information is used to determine the non-normalized weather billed energy forecast by applying the forecasted number of customer/connection from Table 3-20 by the forecast of annual usage per customer/connection from Table 3-22. The resulting non-normalized weather billed PUC forecast is shown in the following Table 3-23.

Table 3-23: Non-normalized Weather Billed PUC Distribution Forecast (2020 and 2021 COVID Normalized)

Year	Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load	Total
NON-normalized Weather Billed Energy Forecast (GWh)							
2022	287.7	88.3	235.3	0.2	2.5	0.9	614.8
2023	282.9	87.2	233.5	0.2	2.5	0.9	607.1

The non-normalized weather billed energy forecast has been determined but it needs to be adjusted in order to be aligned with the total weather normalized billed energy forecast. As previously determined, the total weather normalized billed energy forecast is 602.7 (GWh) for 2022 and 593.5 (GWh) for 2023.

The difference between the non-normalized and normalized forecast adjustments is (12.1) GWh in 2022 (i.e. 602.7 – 614.8) and (13.6) GWh in 2018 (i.e. 593.5 – 607.1). The difference is assumed to be the adjustment needed to move the forecast to a weather normal basis and this amount will be assigned to those rate classes that are weather sensitive. PUC used the same weather sensitivity percentages as presented in its 2018 COS Application (EB-2017-0071). The following table 3-24 represents the percentages used.

Table 3-24: Weather Sensitivity by Rate Class

Residential	General Service < 50 kW	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Unmetered Scattered Load
Weather Sensitivity					
92.7%	92.7%	85.3%	0.0%	0.0%	0.0%

For the GS > 50 kW class a weather sensitivity amount of 85.3% was provided in the weather normalization work completed by Hydro One. For the Residential and GS < 50 kW classes, it was assumed in the 2018 COS application that the weather sensitivity for the Residential and GS < 50 kW classes was mid-way between 100.0% and 85.3%, or 92.7%. This assumption has been maintained in this application.

The difference between the non-normalized and normalized forecast of (12.1) GWh in 2022 and (13.6) GWh in 2023 has been assigned on a pro rata basis to each rate class based on the above level of weather sensitivity.

3.1.3 Normalized Average use per Customer ("NAC") Model

PUC did not use this methodology.

3.1.4 CDM Adjustment and LRAMVA

CDM Adjustment

On December 20, 2021 the OEB issued a report *Conservation and Demand Management Guidelines for Electricity Distributors* which provided updated guidance on the role of CDM for regulated LDCs. PUC has reviewed these guidelines which resulted in a manual adjustment to the load forecast for CDM. This CDM adjustment has been made to reflect the impact of CDM activities that are expected to be implemented from 2023 to 2027 within PUC's service territory based on its share of electricity use within the province, the IESO's 2021-2024 Conservation Demand Management Framework, and the IESO Planning Outlook. No CDM adjustment is required for PUC's CDM programs offered under the Conservation First Framework, as there were no projects completed in 2021, and the use of actual load data for 2021 in the forecast means that the impact of CFF programs is already fully captured in the load forecast.

The IESO's Planning Outlook indicates that conservation activities will continue to be implemented in 2023 and beyond. IESO's forecast of CDM impacts between 2023 and 2027 are shown on Table 3-25. These programs will put downward pressure on PUC's billing determinants, which makes it appropriate to consider CDM impacts throughout the 5-year period in the 2023 COS load forecast. The average over the five years is considered as there is no LRAMVA or other adjustment that will capture the plans to grow CDM savings over the same period the forecast applies to.

Table 3-25: Province-wide Annual Energy Conservation Savings (TWh)

Program	2023	2024	2025	2026	2027	Average
2021 - 2024 CDM Framework	1.43	2.11	2.73	2.94	2.94	2.43
Climate Action Incentive Fund	0.83	1.10	1.06	1.00	0.90	0.98
Green Municipal Fund	0.03	0.04	0.05	0.06	0.07	0.05
Greener Homes Grant	0.12	0.17	0.21	0.25	0.29	0.21
Post 2024 IESO Programs	0.00	0.00	0.14	0.70	1.48	0.46

Source: IESO. 2022. Demand-Forecast-Model-Data_1.xlsb

These savings are attributed to customer classes based on PUC's historic allocation of the 2015-2020 CDM Framework.

The IESO programs delivered in 2021 will already be partly captured in the load data used in the regression analysis, therefore a weighting factor of 0.5 is assigned to IESO planned savings in 2021 that persist through the forecast horizon. IESO's planned savings for 2021-2024 are shown on Table 3-26.

Table 3-26: IESO 2021-2024 Planned CDM Savings by Program (GWh/a)

2021-2024 CDM Framework				
Program	**2021**	**2022**	**2023**	**2024**
Retrofit Program	354.3	337.8	217.2	217.2
Small Business Program	40.2	28.5	14.3	15.3
Energy Performance Program	21.8	17.3	34.1	35.6
Energy Management	16.4	47.3	115.2	115.2
Customer Solutions	0	0	325.7	325.7
Local Initiatives	52.4	52.4	62.9	62.9
Energy Affordability Program	47.6	50.3	52.3	54
First Nations Program	10.3	7.3	7.3	7.3
Total	**543.0**	**540.9**	**829.0**	**833.2**

Source: IESO. 2021. 2021-2024 Conservation and Demand Management Framework. https://ieso.ca/-/media/Files/SaveOnEnergy/2021-2024-CDM-Framework-Program-Plan.ashx, p.24.

The cumulative savings from these programs, and the estimated allocation across rate classes applicable to PUC are shown on Table 3-27. These savings are slightly higher than those in the IESO forecast. The values in the IESO forecast are used for PUC's analysis, with the allocation across rate classes from the IESO 2021-2024 plan.

Table 3-27 Allocation of IESO Programs in the 2021-2024 Framework Applicable to PUC

Program	Cumulative savings in 2024 (GWh)	Cumulative savings (%)	Estimated allocation for PUC		
			Residential	GS<50	GS>50
Retrofit Program	949.35	38.4%	0.0%	24.4%	75.6%
Small Business Program	78.20	3.2%	0.0%	100.0%	0.0%
Energy Performance Program	97.90	4.0%	0.0%	24.4%	75.6%
Energy Management	285.90	11.6%	0.0%	24.4%	75.6%
Customer Solutions	651.40	26.3%	0.0%	24.4%	75.6%
Local Initiatives	204.40	8.3%	0.0%	0.0%	0.0%
Energy Affordability Program	180.40	7.3%	100.0%	0.0%	0.0%
First Nations Program	27.05	1.1%	0.0%	0.0%	0.0%
Total	**2,474.60**	**100.0%**	**7.3%**	**22.7%**	**60.7%**

Notes: Cumulative savings in 2024 are calculated from Table 3-26 with 2021 at 50% as half of those savings are already captured in PUC's regression analysis
Allocation of business programs other than the Small Business Program is based on PUC's results for the Retrofit Program in 2015-2017

The overall allocation is assumed to be the same in the post-2024 period.

In addition to the IESO programs, Table 3-25 includes several federal programs that IESO forecasts will impact on electricity demand in Ontario, including a green homes program, and programs targeted at Small and Medium Enterprises ("SMEs")Es (up to 499 employees) and the Municipalities, Universities, School Boards and Hospitals ("MUSH") sector. The non-residential programs are assumed to yield savings proportional to energy use in the general service rate classes. These programs are scaled to PUC based on its share of total metered kWh in the province.

Based on the estimated savings and the allocations described above, the average overall annual impact of conservation initiatives on PUC's load in the 2023 to 2027 period not captured by the regression data are shown on Table 3-28.

An adjustment is applied to the forecast CDM results as the estimated value captured in the load forecast is based on an earlier estimate. The adjustment will be removed at the time other changes are made to the load forecast.

Table 3-28: Annual adjustment required to forecast for CDM in 2023-2027 (kWh)

Program	PUC manual adjustment for CDM (kWh)			
	Residential	GS<50	GS>50	Total
Program	1,080,723	3,730,287	5,508,418	10,319,429
Less 1/2 of estimated 2021 savings	(90,266)	(311,566)	(460,081)	(861,912)
Climate Action Incentive Fund	-	1,798,141	2,661,234	4,459,375
Green Municipal Fund	-	91,929	136,055	227,984
Greener Homes Grant	1,434,227	-	-	1,434,227
Post 2024 IESO Programs	206,360	712,285	1,051,813	1,970,459
Sub-total	**2,631,046**	**6,021,077**	**8,897,439**	**17,549,562**
Proposed loss factor	4.62%			
Total CDM results forecast	**2,752,600**	**6,299,251**	**9,308,501**	**18,360,352**
Adjustment to match load forecast	-40%	-3%	-25%	
CDM adjustment to load forecast	**1,643,785**	**6,084,747**	**7,026,072**	**14,754,604**

Billed KW Load Forecast

There are three rate classes that charge volumetric distribution on a kW basis. These include GS 50 to 4,999 kW, Sentinel Lights and Street Lights. The forecast of kW for GS 50 to 4,999 kW and Sentinel Lights classes is based on a review of the historical ratio of kW to kWh and applying the average ratio to the forecasted kWh to produce the required kW.

The following Table 3-29 outlines the annual demand units by applicable rate class on actual and weather normal basis. The weather normal values are actual values adjusted by the weather normal conversion factor outlined in Table 3-17.

Table 3-29: Historic Annual kW Applicable Rate Class (2020 and 2021 COVID Normalized)

Year	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Total	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Total
Billed Annual kW								
	Actual				**Weather Normal**			
2009	637,622	730	21,346	659,698	629,411	721	21,071	651,203
2010	635,104	714	23,264	659,082	642,188	722	23,524	666,434
2011	629,024	703	21,619	651,346	631,709	706	21,711	654,126
2012	627,836	687	21,596	650,119	646,433	707	22,236	669,376
2013	656,137	660	21,588	678,385	645,100	649	21,225	666,974
2014	634,289	676	21,876	656,841	617,201	658	21,287	639,145
2015	711,311	752	21,794	733,857	703,362	744	21,550	725,656
2016	622,066	630	14,262	636,959	630,691	639	14,460	645,790
2017	610,764	619	7,030	618,413	619,508	628	7,131	627,267
2018	604,549	612	7,030	612,191	589,879	597	6,860	597,336
2019	594,560	605	7,056	602,221	582,884	593	6,917	590,395
2020	546,908	598	7,202	554,707	547,801	598	7,214	555,613
2021	536,707	596	7,202	544,505	561,332	624	7,532	569,488

The following Table 3-30 shows the historical ratio of kW/kWh as well as the average.

Table 3-30: Historical kW/kWh Ratio per Applicable Rate Class

Year	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights
Ratio of kW to kWh			
2008	0.2492%	0.2768%	0.2797%
2009	0.2462%	0.2781%	0.2808%
2010	0.2471%	0.2766%	0.3000%
2011	0.2457%	0.2700%	0.2766%
2012	0.2469%	0.2787%	0.2791%
2013	0.2533%	0.2781%	0.2669%
2014	0.2451%	0.2778%	0.2800%
2015	0.2792%	0.3197%	0.2987%
2016	0.2489%	0.2775%	0.2929%
2017	0.2491%	0.2898%	0.2931%
2018	0.2500%	0.2926%	0.2931%
2019	0.2470%	0.2926%	0.2927%
2020	0.2289%	0.2927%	0.2917%
2021	0.2264%	0.2929%	0.2928%
Average 2011 to 2021	0.2473%	0.2875%	0.2871%
Used for Forecast	0.2473%	0.2875%	0.2871%

The following Table 3-31 outlines the forecast of kW for the applicable rate classes.

Table 3-31: kW Forecast by Applicable Rate Class

Year	General Service 50 to 4,999 kW	Sentinel Lighting	Street Lights	Total
Predicted Billed kW				
2022	570,894	580	7,200	578,675
2023	547,687	566	7,200	555,454

Table 3-32 provides a summary of the total load forecast on a power purchased and billed level from 2018 Board Approved to 2023 Test Year.

Table 3-32: Summary of Total Load Forecast (2020 & 2021 COVID Normalized)

	2018 Board Approved	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Bridge Year	2023 Test Year
Purchases							
Actual kWh Purchases		666,736,298	660,639,514	659,068,596	647,740,937		
Predicted kWh Purchases before	659,159,220	684,015,773	671,082,095	647,283,485	610,764,456	630,498,752	620,948,538
% Difference between actual and predicted purchases		2.6%	1.6%	(1.8%)	(5.7%)		
Loss Factor						1.0462	1.0462
Total Billed Before CDM Adjustments						602,656,043	593,527,565
CDM Adjustment						0	0
Total Billed After Adjustments		633,697,927	631,945,814	631,179,704	622,536,838	602,656,043	593,527,565
Billing Determinants							
Residential							
Customers	29,816	29,837	29,897	30,026	30,134	30,237	30,340
kWh	288,323,799	295,617,651	296,035,266	298,184,963	292,492,184	281,801,295	274,738,681
General Service < 50 kW							
Customers	3,431	3,414	3,388	3,355	3,423	3,397	3,400
kWh	92,411,463	92,759,999	91,718,380	84,774,528	88,569,433	86,483,996	79,051,528
General Service 50 to 4,999 kW							
Customers	357	362	362	370	308	348	344
kWh	244,620,697	241,817,729	240,708,316	227,128,751	219,715,371	230,833,868	221,450,388
kW	614,743	604,549	594,560	546,908	536,707	570,894	547,687
Sentinel Lighting							
Connections	354	355	350	348	330	324	317
kWh	209,800	209,111	206,826	204,140	203,611	198,666	193,841
kW	593	612	605	598	596	580	566
Street Lights							
Connections	8,070	8,070	8,037	8,037	8,037	8,037	8,037
kWh	2,398,221	2,398,221	2,410,546	2,468,997	2,459,994	2,459,994	2,459,994
kW	7,030	7,030	7,056	7,202	7,202	7,200	7,200
Unmetered Scattered Load							
Connections	22	23	23	24	24	25	25
kWh	944,731	895,217	866,480	870,821	877,918	878,223	878,528
Total							
Customer/Connections	42,050	42,061	42,057	42,183	42,272	42,367	42,463
kWh	628,908,711	633,697,927	631,945,814	631,179,704	622,536,838	602,656,043	578,772,961
kW from applicable classes	622,366	612,191	602,221	554,707	544,505	578,675	555,454

3.2 ACCURACY OF LOAD FORECAST AND VARIANCE ANALYSES

The following discussion provides a year over year variance analysis on PUC's distribution revenue and billing determinants. The variance analysis will compare 2018 Board Approved to 2018 Actual; 2018 Actual to 2019 Actual; 2019 Actual to 2020 Actual; 2020 Actual to 2021 Actual; 2021 Actual to 2022 Bridge and 2022 Bridge Year to 2023 Test Year. The distribution revenue variance analysis is based on information provided in Table 3-1. The billing determinant variance analysis is based on data outlined in Table 3-33. The overall variance analysis has been provided based on PUC Distribution's materiality of $135,000, as noted earlier in Exhibit 1 of this Application.

2018 Board Approved vs. 2018 Actual

Table 3-33: Distribution Revenue - 2018 Board Approved vs 2018 Actual

Distribution Throughput Revenue	2018 Board Approved	2018 Actual	Difference $	Difference %
Residential	11,226,807	9,190,889	(2,035,918)	(18.1%)
General Service <50 kW	3,149,458	3,119,001	(30,457)	(1.0%)
General Service 50 to 4,999 kW	4,544,464	4,149,200	(395,264)	(8.7%)
Sentinel Lighting	34,742	76,498	41,756	120.2%
Street Lighting	195,345	395,492	200,147	102.5%
Unmetered Scattered Load	39,551	29,910	(9,641)	(24.4%)
Total	**19,190,367**	**16,960,991**	**(2,229,376)**	**(11.6%)**

Throughput revenue for 2018 was $2,229,376 or 12.00% lower than the amounts approved in the 2018 COS due to the revised rates not being in effective for the full year (effective October 1, 2018) and lower actual consumption vs. predicted consumption.

Table 3-34: Billing Determinants – 2018 Board Approved vs 2018 Actual

Billing Quantiites	Customers / Connections		Units	Volume		Volume Weather Normal		Annual Usage Per Customer / Connection		Annual Usage Per Customer / Connection Weather Normal	
Weather Normal Conversion Factor							0.9832				
	2018 Board Approved	2018 Actual		2018 Board Approved	2018 Actual	2018 Board Approved	2018 Actual	2018 Board Approved	2018 Actual	2018 Board Approved	2018 Actual
Residential	29,816	29,837	kWh	288,323,799	295,617,651	288,323,799	290,645,087	9,670	9,908	9,670	9,741
General Service < 50 kW	3,431	3,414	kWh	92,411,463	92,759,999	92,411,463	91,199,690	26,934	27,170	26,934	26,713
General Service 50 to 4,999 kW	357	362	kW	614,743	604,549	614,743	594,380	1,722	1,670	1,722	1,642
Sentinel Lighting	354	355	kW	593	612	593	602	2	2	2	2
Street Lights	8,070	8,070	kW	7,030	7,030	7,030	6,912	1	1	1	1
Unmetered Scattered Load	22	23	kWh	944,731	895,217	944,731	880,159	42,942	38,922	42,942	38,268
Total	42,050	42,061									
	Variance			Variance		Variance		Variance		Variance	
Residential	21		kWh	7,293,852		2,321,288		238		71	
General Service < 50 kW	(17)		kWh	348,536		(1,211,773)		236		(221)	
General Service 50 to 4,999 kW	5		kW	(10,194)		(20,363)		(52)		(80)	
Sentinel Lighting	1		kW	19		9		0		0	
Street Lights	0		kW	0		(118)		0		(0)	
Unmetered Scattered Load	1		kWh	(49,514)		(64,572)		(4,020)		(4,675)	

When comparing the 2018 actual results to the 2018 board approved amounts, the customer/connection forecast for 2018 was fairly consistent with 2018 actual values. The residential class had higher actual consumption at 7.3M kWh or 2.53% more. All other classes consumption variability was insignificant.

2018 Actual vs. 2019 Actual

Table 3-35: Distribution Revenue – 2018 Actual vs 2019 Actual

Distribution Throughput Revenue	2018 Actual	2019 Actual	Difference $	Difference %
Residential	9,190,889	11,169,040	1,978,150	21.5%
General Service <50 kW	3,119,001	3,118,156	(845)	(0.0%)
General Service 50 to 4,999 kW	4,149,200	4,411,624	262,424	6.3%
Sentinel Lighting	76,498	33,694	(42,804)	(56.0%)
Street Lighting	395,492	303,433	(92,060)	(23.3%)
Unmetered Scattered Load	29,910	35,221	5,311	17.8%
Total	**16,960,991**	**19,071,168**	**2,110,177**	**12.4%**

The 2019 throughput revenue was $2,110,177 or 12% higher than 2018 actual revenue due to the increase in rates being in effect for the full year. The 2019 revenue was still below the 2018 board approved revenue mainly due to lower consumption.

Table 3-36: Billing Determinants - 2018 Actual vs 2019 Actual

Billing Quantiites	Customers / Connections		Units	Volume		Volume Weather Normal		Annual Usage Per Customer / Connection		Annual Usage Per Customer / Connection Weather Normal	
Weather Normal Conversion Factor						0.983179072	0.9731				
	2018 Actual	2019 Actual		2018 Actual	2019 Actual	2018 Actual	2019 Actual	2018 Actual	2019 Actual	2018 Actual	2019 Actual
Residential	29,837	29,897	kWh	295,617,651	296,035,266	290,645,087	288,059,870	9,908	9,902	9,741	9,635
General Service < 50 kW	3,414	3,388	kWh	92,759,999	91,718,380	91,199,690	89,247,424	27,170	27,072	26,713	26,342
General Service 50 to 4,999 kW	362	362	kW	604,549	594,560	594,380	578,542	1,670	1,642	1,642	1,598
Sentinel Lighting	355	350	kW	612	605	602	589	2	2	2	2
Street Lights	8,070	8,037	kW	7,030	7,056	6,912	6,866	1	1	1	1
Unmetered Scattered Load	23	23	kWh	895,217	866,480	880,159	843,136	38,922	37,673	38,268	36,658
Total	42,061	42,057									
	Variance			Variance		Variance		Variance		Variance	
Residential	60		kWh	417,615		(2,585,217)		(6)		(106)	
General Service < 50 kW	(26)		kWh	(1,041,619)		(1,952,266)		(99)		(371)	
General Service 50 to 4,999 kW	0		kW	(9,989)		(15,838)		(28)		(44)	
Sentinel Lighting	(5)		kW	(7)		(13)		0		(0)	
Street Lights	(33)		kW	26		(46)		0		(0)	
Unmetered Scattered Load	0		kWh	(28,737)		(37,022)		(1,249)		(1,610)	

There is no material differences in the customer connections or usage per customer between 2018 and 2019.

2019 Actual vs. 2020 Actual

Table 3-37: Distribution Revenue - 2019 Actual vs 2020 Actual

Distribution Throughput Revenue	2019 Actual	2020 Actual	Difference $	Difference %
Residential	11,169,040	11,478,211	309,172	2.8%
General Service <50 kW	3,118,156	3,006,431	(111,725)	(3.6%)
General Service 50 to 4,999 kW	4,411,624	4,273,136	(138,488)	(3.1%)
Sentinel Lighting	33,694	35,565	1,872	5.6%
Street Lighting	303,433	201,052	(102,380)	(33.7%)
Unmetered Scattered Load	35,221	37,840	2,619	7.4%
Total	**19,071,168**	**19,032,237**	**(38,931)**	**(0.2%)**

The 2020 throughput revenue was ($38,931) or virtually unchanged from 2020.

Table 3-38: Billing Determinants - 2019 Actual vs 2020 Actual

Billing Quantiites	Customers / Connections		Units	Volume		Volume Weather Normal		Annual Usage Per Customer / Connection		Annual Usage Per Customer / Connection Weather Normal	
Weather Normal Conversion Factor						0.973059307	0.9888				
	2019 Actual	2020 Actual		2019 Actual	2020 Actual	2019 Actual	2020 Actual	2019 Actual	2020 Actual	2019 Actual	2020 Actual
Residential	29,897	30,026	kWh	296,035,266	298,184,963	288,059,870	294,852,697	9,902	9,931	9,635	9,820
General Service < 50 kW	3,388	3,355	kWh	91,718,380	84,774,528	89,247,424	83,827,159	27,072	25,268	26,342	24,986
General Service 50 to 4,999 kW	362	370	kW	594,560	546,908	578,542	540,796	1,642	1,478	1,598	1,462
Sentinel Lighting	350	348	kW	605	598	589	591	2	2	2	2
Street Lights	8,037	8,037	kW	7,056	7,202	6,866	7,121	1	1	1	1
Unmetered Scattered Load	23	24	kWh	866,480	870,821	843,136	861,090	37,673	36,284	36,658	35,879
Total	42,057	42,160									
	Variance			Variance		Variance		Variance		Variance	
Residential	129		kWh	2,149,697		6,792,827		29		185	
General Service < 50 kW	(33)		kWh	(6,943,852)		(5,420,265)		(1,803)		(1,356)	
General Service 50 to 4,999 kW	8		kW	(47,652)		(37,746)		(164)		(137)	
Sentinel Lighting	(2)		kW	(8)		2		(0)		0	
Street Lights	0		kW	146		256		0		0	
Unmetered Scattered Load	1		kWh	4,341		17,953		(1,389)		(779)	

As outlined earlier, PUC's 2020 year was affected by the COVID-19 pandemic. There is an 8% drop in consumption for the small and large general service rate classes. In 2020, after weather normalization, there is still a 6% and 7% drop respectively in these classes, meaning that another outside influence affected consumption in the year. There was also a 7% and 10% drop respectively in the usage per customer for those rate classes. All these above findings point to the effects of COVID-19.

2020 Actual vs. 2021 Actual

Table 3-39: Distribution Revenue - 2020 Actual vs 2021 Actual

Distribution Throughput Revenue	2020 Actual	2021 Actual	Difference $	Difference %
Residential	11,478,211	11,764,831	286,620	2.5%
General Service <50 kW	3,006,431	3,152,286	145,854	4.9%
General Service 50 to 4,999 kW	4,273,136	4,277,868	4,731	0.1%
Sentinel Lighting	35,565	36,363	798	2.2%
Street Lighting	201,052	207,431	6,379	3.2%
Unmetered Scattered Load	37,840	38,846	1,006	2.7%
Total	**19,032,237**	**19,477,625**	**445,388**	**2.3%**

The 2021 throughput revenue was $445,388 or 2.0% higher than the 2020 actual revenue. The 2021 revenue includes a rate rider for foregone revenue that was delayed implementation in 2020 as a result of the COVID-19 pandemic.

Table 3-40: Billing Determinants - 2020 Actual vs 2021 Actual (2020 and 2021 COVID Normalized)

Billing Quantiites	Customers / Connections		Units	Volume		Volume Weather Normal		Annual Usage Per Customer / Connection		Annual Usage Per Customer / Connection Weather Normal	
Weather Normal Conversion Factor						0.988824836	1.0139				
	2020 Actual	2021 Actual		2020 Actual	2021 Actual	2020 Actual	2021 Actual	2020 Actual	2021 Actual	2020 Actual	2021 Actual
Residential	30,026	30,134	kWh	298,184,963	292,492,184	294,852,697	296,547,437	9,931	9,706	9,820	9,841
General Service < 50 kW	3,355	3,423	kWh	84,774,528	88,569,433	83,827,159	89,797,402	25,268	25,875	24,986	26,234
General Service 50 to 4,999 kW	370	308	kW	546,908	536,707	540,796	544,148	1,478	1,743	1,462	1,767
Sentinel Lighting	348	330	kW	598	596	591	605	2	2	2	2
Street Lights	8,037	8,037	kW	7,202	7,202	7,121	7,302	1	1	1	1
Unmetered Scattered Load	24	24	kWh	870,821	877,918	861,090	890,090	36,284	36,580	35,879	37,087
Total	42,160	42,256									
	Variance			Variance		Variance		Variance		Variance	
Residential	108		kWh	(5,692,779)		1,694,740		(225)		21	
General Service < 50 kW	68		kWh	3,794,905		5,970,243		607		1,248	
General Service 50 to 4,999 kW	(62)		kW	(10,201)		3,352		264		305	
Sentinel Lighting	(18)		kW	(1)		14		0		0	
Street Lights	0		kW	0		180		0		0	
Unmetered Scattered Load	0		kWh	7,097		29,000		296		1,208	

As explained in the COVID adjustment, there is a 17.0% or 62 customer decrease in the large general service class. All of these customers shifted to the small general service rate class. This also caused the annual usage per customer in the large GS rate class to go up by 18.0%.

2021 Actual vs. 2022 Bridge

Table 3-41: Distribution Revenue – 2021 Actual vs 2022 Bridge

Distribution Throughput Revenue	2021 Actual	2022 Bridge	Difference $	Difference %
Residential	11,764,831	12,893,279	1,128,447	9.6%
General Service <50 kW	3,152,286	3,401,209	248,923	7.9%
General Service 50 to 4,999 kW	4,277,868	4,903,411	625,543	14.6%
Sentinel Lighting	36,363	37,505	1,142	3.1%
Street Lighting	207,431	222,361	14,930	7.2%
Unmetered Scattered Load	38,846	42,376	3,530	9.1%
Total	**19,477,625**	**21,500,141**	**2,022,516**	**10.4%**

Throughput revenue for 2022 is forecasted to be $2,022,516 or 10.0% higher than 2021. The 2022 revenue includes the following factors that contribute to this 10.0% increase:

- IRM inflationary increase of 3.0% or $599,510
- ICM Rate Rider for Sault Smart Grid which totals $875,868 in additional revenue
- forecasted consumption that returns closer to pre pandemic levels

<u>Table 3-42: Billing Determinants - 2021 Actual vs 2022 Bridge</u>
<u>(2020 and 2021 COVID Normalized)</u>

Billing Quantiites	Customers / Connections		Units	Volume		Volume Weather Normal		Annual Usage Per Customer / Connection		Annual Usage Per Customer / Connection Weather Normal	
Weather Normal Conversion Factor						1.013864481	1.0143				
	2021 Actual	2022 Bridge		2021 Actual	2022 Bridge	2021 Actual	2022 Bridge	2021 Actual	2022 Bridge	2021 Actual	2022 Bridge
Residential	30,134	30,237	kWh	292,492,184	281,801,295	296,547,437	285,835,593	9,706	9,320	9,841	9,453
General Service < 50 kW	3,423	3,397	kWh	88,569,433	86,483,996	89,797,402	87,722,111	25,875	25,460	26,234	25,825
General Service 50 to 4,999 kW	308	348	kW	536,707	570,894	544,148	579,067	1,743	1,639	1,767	1,662
Sentinel Lighting	330	324	kW	596	580	605	589	2	2	2	2
Street Lights	8,037	8,037	kW	7,202	7,200	7,302	7,303	1	1	1	1
Unmetered Scattered Load	24	25	kWh	877,918	878,223	890,090	890,796	36,580	35,748	37,087	36,259
Total	42,256	42,367									
	Variance			Variance		Variance		Variance		Variance	
Residential	103		kWh	(10,690,889)		(10,711,843)		(387)		(388)	
General Service < 50 kW	(26)		kWh	(2,085,437)		(2,075,291)		(414)		(409)	
General Service 50 to 4,999 kW	40		kW	34,187		34,919		(104)		(104)	
Sentinel Lighting	(6)		kW	(16)		(16)		(0)		(0)	
Street Lights	0		kW	(2)		1		(0)		0	
Unmetered Scattered Load	1		kWh	305		706		(832)		(828)	

The only material variance is in the large general service rate class, which is projecting that the number of customers and resulting consumption will return back to pre-pandemic levels.

2022 Bridge vs. 2023 Test

Table 3-43: Distribution Revenue - 2022 Bridge vs 2023 Test

Distribution Throughput Revenue	2022 Bridge	2023 Test	Difference $	Difference %
Residential	12,893,279	15,291,103	2,397,824	18.6%
General Service <50 kW	3,401,209	3,768,919	367,710	10.8%
General Service 50 to 4,999 kW	4,903,411	5,498,738	595,327	12.1%
Sentinel Lighting	37,505	43,297	5,792	15.4%
Street Lighting	222,361	262,895	40,534	18.2%
Unmetered Scattered Load	42,376	50,271	7,895	18.6%
Total	**21,500,141**	**24,915,223**	**3,415,082**	**15.9%**

The proposed Test Year distribution revenue is a reflection of the 2023 COS application and the proposed base revenue requirement of $24,915,223. The variance in distribution revenue over the Bridge Year is a result of the proposed increases to fixed and variable distribution revenue in the Test Year.

Table 3-44: Billing Determinants - 2022 Bridge vs 2023 Test

Billing Quantiites	Customers / Connections		Units	Volume		Volume Weather Normal		Annual Usage Per Customer / Connection		Annual Usage Per Customer / Connection Weather Normal	
Weather Normal Conversion Factor						1.01431611	0.9757				
	2022 Bridge	2023 Test		2022 Bridge	2023 Test	2022 Bridge	2023 Test	2022 Bridge	2023 Test	2022 Bridge	2023 Test
Residential	30,237	30,340	kWh	281,801,295	274,738,681	285,835,593	268,072,180	9,320	9,055	9,453	8,836
General Service < 50 kW	3,397	3,400	kWh	86,483,996	79,051,528	87,722,111	77,133,352	25,460	23,250	25,825	22,686
General Service 50 to 4,999 kW	348	344	kW	570,894	547,687	579,067	534,398	1,639	1,592	1,662	1,553
Sentinel Lighting	324	317	kW	580	566	589	553	2	2	2	2
Street Lights	8,037	8,037	kW	7,200	7,200	7,303	7,025	1	1	1	1
Unmetered Scattered Load	25	25	kWh	878,223	878,528	890,796	857,211	35,748	35,141	36,259	34,288
Total	42,367	42,463									
	Variance			Variance		Variance		Variance		Variance	
Residential	103		kWh	(7,062,614)		(17,763,413)		(264)		(618)	
General Service < 50 kW	3		kWh	(7,432,469)		(10,588,759)		(2,210)		(3,139)	
General Service 50 to 4,999 kW	(4)		kW	(23,207)		(44,670)		(47)		(109)	
Sentinel Lighting	(7)		kW	(14)		(36)		(0)		(0)	
Street Lights	0		kW	0		(278)		0		(0)	
Unmetered Scattered Load	0		kWh	305		(33,585)		(607)		(1,971)	

There is no material differences in the customer connections between 2022 and 2023. There is a 9.0% or 7.4M kWh drop in small general service consumption. This is due to the shift back of small general service customers to the large general service class.

APPENDIX A

MONTHLY DATA USED FOR

REGRESSION ANALYSIS

	Purchased kWh	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	Trend	Number of Customers	Predicted Purchases
Jan-11	83,643,833	935.0	-	-	31.00	1	33,040	81,611,129
Feb-11	72,687,185	732.3	-	-	28.00	2	33,045	69,285,410
Mar-11	72,688,244	699.2	-	1.00	31.00	3	33,047	70,381,930
Apr-11	60,902,854	444.6	-	1.00	30.00	4	33,047	59,664,918
May-11	52,597,908	221.9	3.2	1.00	31.00	5	33,046	53,891,242
Jun-11	48,777,799	99.4	2.7	-	30.00	6	33,056	50,569,605
Jul-11	54,638,457	14.0	73.6	-	31.00	7	33,071	57,940,637
Aug-11	54,146,196	24.2	35.4	-	31.00	8	33,098	53,533,313
Sep-11	52,585,712	129.6	11.0	1.00	30.00	9	33,126	49,628,689
Oct-11	56,921,149	269.5	1.5	1.00	31.00	10	33,143	55,018,889
Nov-11	61,640,573	428.9	-	1.00	30.00	11	33,199	58,645,655
Dec-11	73,819,284	650.4	-	-	31.00	12	33,248	70,887,721
Jan-12	73,790,226	756.8	-	-	31.00	13	33,203	74,558,153
Feb-12	68,046,427	622.6	-	-	29.00	14	33,203	66,351,923
Mar-12	64,860,708	479.7	-	1.00	31.00	15	33,203	61,879,698
Apr-12	55,490,558	437.5	-	1.00	30.00	16	33,210	58,617,250
May-12	50,211,578	188.3	11.0	1.00	31.00	17	33,210	52,866,598
Jun-12	50,441,593	59.1	33.7	-	30.00	18	33,210	52,163,817
Jul-12	52,218,431	9.5	68.7	-	31.00	19	33,212	56,379,445
Aug-12	51,797,361	34.3	37.7	-	31.00	20	33,212	53,374,318
Sep-12	49,181,637	181.9	5.3	1.00	30.00	21	33,212	49,968,125
Oct-12	55,200,719	343.9	-	1.00	31.00	22	33,055	56,658,033
Nov-12	63,048,824	481.9	-	1.00	30.00	23	33,055	59,718,834
Dec-12	72,665,451	445.9	-	-	31.00	24	33,055	62,926,966
Jan-13	77,430,385	798.2	-	-	31.00	25	33,306	75,215,328
Feb-13	69,794,850	786.1	-	-	28.00	26	33,306	69,578,670
Mar-13	69,264,159	722.5	-	1.00	31.00	27	33,306	69,603,904
Apr-13	62,490,524	495.7	-	1.00	30.00	28	33,294	59,865,552
May-13	51,260,742	248.4	3.0	1.00	31.00	29	33,294	53,201,404
Jun-13	48,246,051	106.2	12.4	-	30.00	30	33,294	50,408,116
Jul-13	52,370,705	47.8	50.3	-	31.00	31	33,515	54,657,526
Aug-13	51,254,455	57.7	31.4	-	31.00	32	33,515	52,616,291
Sep-13	48,184,318	165.6	5.8	1.00	30.00	33	33,515	48,653,029
Oct-13	54,286,247	326.1	-	1.00	31.00	34	33,393	55,225,974
Nov-13	64,675,563	543.7	-	1.00	30.00	35	33,393	61,083,666
Dec-13	81,310,312	874.5	-	-	31.00	36	33,393	77,164,076
Jan-14	84,076,331	980.3	-	-	31.00	37	33,166	80,821,274
Feb-14	73,283,050	912.0	-	-	28.00	38	33,166	73,212,972
Mar-14	75,936,435	895.0	-	1.00	31.00	39	33,166	74,874,661
Apr-14	60,945,928	511.1	-	1.00	30.00	40	33,415	59,608,741
May-14	53,127,584	267.9	0.8	1.00	31.00	41	33,415	52,820,332
Jun-14	47,524,355	96.9	12.0	-	30.00	42	33,415	49,235,841
Jul-14	48,026,904	88.1	6.4	-	31.00	43	33,400	49,887,969
Aug-14	48,878,137	63.4	13.5	-	31.00	44	33,400	49,828,315
Sep-14	47,959,876	158.2	1.4	1.00	30.00	45	33,400	47,065,628
Oct-14	54,613,898	341.0	-	1.00	31.00	46	33,513	54,953,632
Nov-14	64,852,403	616.1	-	1.00	30.00	47	33,513	62,828,156
Dec-14	71,265,383	691.4	-	-	31.00	48	33,513	69,940,967
Jan-15	79,807,046	954.2	-	-	31.00	49	33,539	79,097,710
Feb-15	75,728,990	1,015.2	-	-	28.00	50	33,539	76,027,611
Mar-15	70,753,091	786.6	-	1.00	31.00	51	33,539	70,262,513
Apr-15	57,109,492	474.4	-	1.00	30.00	52	33,261	57,535,794
May-15	49,113,111	242.9	1.1	1.00	31.00	53	33,261	51,194,931
Jun-15	46,018,522	141.8	0.4	-	30.00	54	33,261	48,600,229
Jul-15	50,056,826	52.6	29.2	-	31.00	55	33,371	50,655,933
Aug-15	49,818,190	37.5	35.6	-	31.00	56	33,371	50,847,129
Sep-15	48,683,583	75.5	31.4	1.00	30.00	57	33,371	47,062,481
Oct-15	52,100,033	331.2	-	1.00	31.00	58	33,411	53,822,592
Nov-15	55,680,534	413.0	-	1.00	30.00	59	33,411	54,912,627
Dec-15	63,647,960	541.2	-	-	31.00	60	33,411	63,882,134
Jan-16	71,224,983	794.2	-	-	31.00	61	33,412	72,695,990
Feb-16	65,961,523	731.2	-	-	29.00	62	33,412	66,988,754
Mar-16	61,438,716	588.8	-	1.00	31.00	63	33,412	62,534,079
Apr-16	55,510,528	499.7	-	1.00	30.00	64	33,360	57,628,060
May-16	47,972,678	241.2	3.5	1.00	31.00	65	33,360	50,634,721
Jun-16	46,020,697	116.8	10.2	-	30.00	66	33,360	48,132,354
Jul-16	50,843,952	27.2	44.2	-	31.00	67	33,412	50,816,059
Aug-16	52,655,660	17.1	51.7		31.00	68	33,412	51,318,035
Sep-16	47,273,740	65.1	13.5	1.00	30.00	69	33,412	43,696,567

	Purchased kWh	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	Trend	Number of Customers	Predicted Purchases
Oct-16	50,073,798	277.4	-	1.00	31.00	70	33,513	51,138,459
Nov-16	53,720,228	485.6	-	1.00	30.00	71	33,513	56,665,613
Dec-16	67,261,960	640.7	-	-	31.00	72	33,513	66,577,859
Jan-17	66,674,271	710.9	-	-	31.00	73	33,528	68,975,857
Feb-17	59,162,719	638.7	-	-	28.00	74	33,528	61,230,672
Mar-17	63,923,197	706.2	-	1.00	31.00	75	33,528	65,858,162
Apr-17	51,461,055	392.1	-	1.00	30.00	76	33,482	53,054,782
May-17	48,082,511	273.8	-	1.00	31.00	77	33,482	50,551,751
Jun-17	44,830,072	104.1	3.5	-	30.00	78	33,482	46,065,867
Jul-17	48,264,067	42.0	13.8	-	31.00	79	33,516	46,800,689
Aug-17	47,137,204	58.4	9.2	-	31.00	80	33,516	46,742,837
Sep-17	46,024,413	112.7	33.3	1.00	30.00	81	33,516	47,012,657
Oct-17	48,274,780	266.3	1.9	1.00	31.00	82	33,605	50,187,131
Nov-17	58,218,614	540.9	-	1.00	30.00	83	33,605	57,808,670
Dec-17	70,917,570	849.9	-	-	31.00	84	33,605	73,125,694
Jan-18	71,561,357	860.4	-	-	31.00	85	33,637	73,426,894
Feb-18	62,600,141	769.0	-	-	28.00	86	33,637	65,007,823
Mar-18	61,919,235	737.7	-	1.00	31.00	87	33,637	66,167,607
Apr-18	55,872,651	585.9	-	1.00	30.00	88	33,637	59,058,694
May-18	47,195,638	214.0	5.6	1.00	31.00	89	33,637	48,343,493
Jun-18	45,395,013	104.5	17.1	-	30.00	90	33,637	46,954,440
Jul-18	50,885,922	19.6	59.6	-	31.00	91	33,637	50,850,756
Aug-18	49,660,000	24.6	45.5	-	31.00	92	33,637	49,226,136
Sep-18	45,784,881	135.0	22.5	1.00	30.00	93	33,637	45,670,393
Oct-18	51,981,748	389.2	-	1.00	31.00	94	33,637	53,472,430
Nov-18	59,277,771	604.1	-	1.00	30.00	95	33,637	59,235,795
Dec-18	64,601,941	686.6	-	-	31.00	96	33,637	66,601,313
Jan-19	72,715,952	966.9	-	-	31.00	97	33,670	76,371,975
Feb-19	62,812,602	802.3	-	-	28.00	98	33,670	65,383,713
Mar-19	63,697,945	764.0	-	1.00	31.00	99	33,670	66,297,809
Apr-19	54,097,055	461.0	-	1.00	30.00	100	33,670	53,882,042
May-19	48,408,149	332.6	-	1.00	31.00	101	33,670	51,024,519
Jun-19	44,308,321	126.3	6.6	-	30.00	102	33,670	45,635,307
Jul-19	49,411,220	26.3	41.7	-	31.00	103	33,670	48,091,516
Aug-19	46,460,129	52.5	7.4	-	31.00	104	33,670	44,726,584
Sep-19	43,739,956	128.3	6.8	1.00	30.00	105	33,670	42,711,413
Oct-19	50,062,807	352.3	-	1.00	31.00	106	33,670	51,386,178
Nov-19	59,303,580	615.1	-	1.00	30.00	107	33,670	58,828,994
Dec-19	65,621,798	713.2	-	-	31.00	108	33,670	66,742,044
Jan-20	66,610,656	708.5	-	-	31.00	109	33,775	66,506,613
Feb-20	63,240,830	755.4	-	-	28.00	110	33,798	62,940,640
Mar-20	61,247,214	638.2	-	1.00	31.00	111	33,798	61,085,485
Apr-20	53,304,894	489.5	-	1.00	30.00	112	33,798	54,083,621
May-20	49,102,694	286.7	12.7	1.00	31.00	113	33,798	50,178,514
Jun-20	46,184,027	101.5	15.7	-	30.00	114	33,798	45,087,112
Jul-20	52,834,439	12.3	62.4	-	31.00	115	33,798	49,349,063
Aug-20	49,467,686	38.3	30.7	-	31.00	116	33,798	46,296,886
Sep-20	44,701,634	181.5	-	1.00	30.00	117	33,798	42,945,343
Oct-20	52,557,235	410.8	-	1.00	31.00	118	33,798	52,642,459
Nov-20	55,175,518	437.5	-	1.00	30.00	119	33,798	51,798,581
Dec-20	64,641,769	668.3	-	-	31.00	120	33,798	64,369,168
Jan-21	65,078,364	738	-	-	31.00	121	33,905	66,744,959
Feb-21	62,543,997	800	-	-	28.00	122	33,905	63,702,938
Mar-21	61,303,952	600	-	1.00	31.00	123	33,905	58,934,630
Apr-21	50,610,121	393	-	1.00	30.00	124	33,905	49,897,946
May-21	46,990,075	266	7	1.00	31.00	125	33,905	47,970,685
Jun-21	46,876,886	71	25	-	30.00	126	33,905	44,385,446
Jul-21	49,479,150	34	28	-	31.00	127	33,905	45,048,626
Aug-21	52,448,762	8	69	-	31.00	128	33,905	49,109,188
Sep-21	44,433,578	118	3	1.00	30.00	129	33,905	40,250,874
Oct-21	48,204,018	209	3	1.00	31.00	130	33,905	45,136,066
Nov-21	55,185,303	500	-	1.00	30.00	131	33,905	53,210,197
Dec-21	64,586,731	649	-	-	31.00	132	33,905	62,902,728

	Purchased kWh	Heating Degree Days	Cooling Degree Days	Spring Fall Flag	Number of Days in Month	CDM Activity	Number of Customers	Predicted Purchases
Jan-15	79,807,046	923.4	-	-	31.00	1,849,138	33,539	81,336,085
Feb-15	75,728,990	1,015.2	-	-	28.00	1,839,519	33,539	79,578,487
Mar-15	70,753,091	786.6	-	1.00	31.00	1,829,900	33,539	73,065,753
Apr-15	57,109,492	474.4	-	1.00	30.00	1,820,281	33,261	58,127,899
May-15	49,113,111	242.9	1.1	1.00	31.00	1,810,663	33,261	50,855,652
Jun-15	46,018,522	141.8	0.4	-	30.00	1,801,044	33,261	47,886,293
Jul-15	50,056,826	52.6	29.2	-	31.00	1,791,425	33,371	48,901,672
Aug-15	49,818,190	37.5	35.6	-	31.00	1,781,806	33,371	48,875,258
Sep-15	48,683,583	75.5	31.4	1.00	30.00	1,772,187	33,371	45,358,655
Oct-15	52,100,033	331.2	-	1.00	31.00	1,762,568	33,411	54,848,251
Nov-15	55,680,534	413.0	-	1.00	30.00	1,752,949	33,411	56,324,297
Dec-15	63,647,960	541.2	-	-	31.00	1,743,330	33,411	66,174,312
Jan-16	71,224,983	794.2	-	-	31.00	1,827,421	33,412	75,939,663
Feb-16	65,961,523	731.2	-	-	28.00	1,911,513	33,412	67,674,530
Mar-16	61,438,716	588.8	-	1.00	31.00	1,995,604	33,412	64,248,681
Apr-16	55,510,528	499.7	-	1.00	30.00	2,079,695	33,360	58,439,986
May-16	47,972,678	241.2	3.5	1.00	31.00	2,163,786	33,360	49,950,285
Jun-16	46,020,697	116.8	8.6	-	30.00	2,247,878	33,360	46,197,294
Jul-16	50,843,952	27.2	44.2	-	31.00	2,331,969	33,412	47,273,010
Aug-16	52,655,660	17.1	51.7	-	31.00	2,416,060	33,412	47,193,536
Sep-16	47,273,740	65.1	12.8	1.00	30.00	2,500,152	33,412	40,806,014
Oct-16	50,073,798	277.4	-	1.00	31.00	2,584,243	33,513	49,950,287
Nov-16	53,720,228	485.6	-	1.00	30.00	2,668,334	33,513	56,114,410
Dec-16	67,261,960	640.7	-	-	31.00	2,752,425	33,513	66,688,933
Jan-17		830.8	-	-	31.00	2,702,650	33,508	73,989,996
Feb-17		774.6	-	-	29.00	2,652,875	33,508	68,303,227
Mar-17		674.2	-	1.00	31.00	2,603,100	33,508	65,227,719
Apr-17		433.9	0.0	1.00	30.00	2,553,325	33,456	53,891,097
May-17		225.3	5.2	1.00	31.00	2,503,550	33,456	48,018,287
Jun-17		98.1	12.8	-	30.00	2,453,775	33,456	44,860,796
Jul-17		40.4	38.9	-	31.00	2,404,000	33,508	46,896,026
Aug-17		39.9	37.1	-	31.00	2,354,225	33,508	46,912,639
Sep-17		130.9	10.0	1.00	30.00	2,304,450	33,508	43,716,815
Oct-17		302.9	0.4	1.00	31.00	2,254,675	33,609	52,020,549
Nov-17		484.4	-	1.00	30.00	2,204,900	33,609	57,586,023
Dec-17		688.9	-	-	31.00	2,155,125	33,609	70,620,807
Jan-18		830.8	-	-	31.00	2,180,816	33,604	76,162,141
Feb-18		774.6	-	-	28.00	2,206,508	33,604	68,381,812
Mar-18		674.2	-	1.00	31.00	2,232,199	33,604	66,844,497
Apr-18		433.9	0.0	1.00	30.00	2,257,890	33,552	55,229,800
May-18		225.3	5.2	1.00	31.00	2,283,582	33,552	49,079,307
Jun-18		98.1	12.8	-	30.00	2,309,273	33,552	45,644,132
Jul-18		40.4	38.9	-	31.00	2,334,965	33,604	47,402,072
Aug-18		39.9	37.1	-	31.00	2,360,656	33,604	47,141,001
Sep-18		130.9	10.0	1.00	30.00	2,386,347	33,604	43,667,494
Oct-18		302.9	0.4	1.00	31.00	2,412,039	33,706	51,694,306
Nov-18		484.4	-	1.00	30.00	2,437,730	33,706	56,982,097
Dec-18		688.9	-	-	31.00	2,463,422	33,706	69,739,198

EXHIBIT 4

OPERATING EXPENSES

PUC Distribution Inc • EB-2022-0059 • Filed: August 31,2022

TABLE OF CONTENTS

LIST OF TABLES

EXHIBIT 4: OPERATING EXPENSES

4.1. OVERVIEW

Operating costs for PUC Distribution Inc. ("PUC") consists of the required expenditures necessary to maintain and operate its distribution system assets, provide customer service activities, meter, bill and collect payment from customers, and ensure the safety of all stakeholders (public, employees, etc.). These costs enable PUC to maintain distribution service quality and reliability standards that are in compliance with the Distribution System Code and the requirements of other regulatory bodies (OEB, IESO, ESA, and the Ministry of Energy, Northern Development and Mines), while continuing to maintain the level of reliability and service that our community and customers expect from PUC.

PUC determines its Operating, Maintenance and Administration ("OM&A") costs through an analysis of the costs it incurs to operate and maintain the distribution system while remaining responsive to regulatory changes. PUC, through its affiliate PUC Services Inc. ("PUCS") operates using an 'at cost' shared services model. PUC has no employees but rather relies on PUCS to provide the necessary resources to operate the distribution utility. The model allows resources to be allocated to PUC as required especially during times when special or non-recurring projects are undertaken. In general, expenses may fluctuate between categories as more attention is required for a specific category due to a specific need, emergency or a change to regulated/mandated services to be provided. Also, in general, inflationary increases put upward pressure on costs.

4.1.1. OM&A Test Year Levels

PUC's total OM&A expenses from the OEB 2018 approved to the 2023 Test Year are summarized in Table 4-1 below. Total OM&A Expenses in the 2023 Test Year are $13,533,701. PUC proposes to recover total OM&A expenses in distribution rates. In this Exhibit, information is provided on key initiatives, trends, and material year-over-year variances. As well, details on staffing and compensation costs, and details on shared services are provided.

Table 4-1: 2023 Test Year OM&A Expenses

Description	Last Rebasing Year 2018 OEB Approved	2023 Test Year
OM&A	$ 11,176,156	$ 13,533,701

OM&A consists of the required expenditures necessary to maintain and operate PUC's distribution system assets and serve customers. These include the costs associated with metering, billing, collecting from customers, the costs associated with ensuring stakeholders safety (public, employees, etc.) and costs to maintain the distribution business service quality and reliability standards in compliance with the Distribution System Code and other regulatory bodies (IESO, ESA etc.).

PUC believes that the level of planned OM&A expenditures is appropriate, reasonable and takes into consideration customer feedback and preferences, optimal productivity, and improved reliability and service quality. Aligned with historical spend, this level of OM&A ensures PUC will meet government mandated obligations and be able to respond to OEB directives in a timely and responsible fashion.

4.1.2. OM&A Budget Process

The OM&A operating budget is prepared annually by management and is reviewed and approved by the Board of Directors. The budget is prepared prior to the start of each fiscal year and provides a plan against which actual results may be evaluated. Once approved, the budget is only revised if a material change to the plan is required. Capital and operating budgets are formulated to achieve PUC's business objectives in a prudent and sustainable manner while considering customer rate impacts.

The following directives and processes are used to prepare the annual budgets:

- Non-Labour expenses for all department budgets are built using previous year actuals, current year forecast and current year budgets as the base. For example, when compiling the 2022 budget, the previous year actual (2020), the current year forecast (2021), and the current year budget (2021) would be used;
- Significant variances in spending from prior years must be explained;
- Review headcount of each department for accuracy and outline any changes;
- Prepare a total labour budget by department using projected wage and benefit costs. Overtime and account distribution are based on previous years actual plus any identified changes for the future year;
- The Finance department completes an initial consolidation of all departments to develop draft budgets. Finance works with each department to identity variances and other issues for consideration;
- Senior management reviews the draft budgets and makes changes to balance cost control with achieving core objectives. In an effort to contain costs, explore efficiencies and still provide an acceptable level of reliability and customer service, the team looks

in detail for discretionary costs and identifies cost areas that can be delayed or addressed with alternative approaches; and

- Senior management makes a submission to the Board of Directors on the proposed budgets for formal approval.

4.1.3. Associated Cost Drivers and Significant Changes

PUC's OM&A plan is developed to ensure that it continues to provide reliable, efficient and safe energy solutions to the community by achieving its core strategic objectives. The plan was formed by a number of factors, including operational needs (e.g., requirements relating to capital investment; operations and maintenance; and staffing), legislative and regulatory obligations and ongoing engagement with customers.

As shown in Table 4-2, PUC's increase in OM&A spending from the 2018 OEB Approved to the 2023 Test Year amounts to $2,357,545 or 21.1 % over the last 5 years or a compound annual growth rate of 3.9% per year. The OM&A costs in the 2023 Test Year reflect the resourcing mix and work activities required to meet customer expectations, growth and broader public policy requirements.

Table 4-2: 2023 Test Year vs. 2018 Board Approved

Test Year vs 2018 Board Approved	2018 Board Approved	2023 Test Year	Variance
Operations	$4,029,899	$4,434,334	$404,435
Maintenance	$2,106,659	$2,901,131	$794,472
Customer Service	$2,037,039	$2,043,800	$6,762
Administration	$3,002,559	$4,154,436	$1,151,876
Total OM&A	**$11,176,156**	**$13,533,701**	**$2,357,545**
Percentage change			**21.1%**

The increase can be categorized by additional spend in Operations of $404,435, Maintenance of $794,472 and Administration of $1,151,876. In general, other than inflation, the increases are primarily due to the following:

- 2 FTEs as a result of the ongoing OM&A associated with Sault Smart Grid ("SSG"), estimated at $260,000 [ICM SSG EB-2018-0219/2020-0249];
- Updates to the PUC Services Shared Cost Allocation Model, filed as Appendix B in Exhibit 4, outlining an increase of $160,000; and
- Increased Cyber Security, Regulatory and IT resources (i.e., Green Button and APB Benchmarking) resulting in increased costs of $123,000.

This will be discussed in detail further in this Exhibit.

4.1.4. Inflation and Overall Trends

PUC provides a reliable supply of electricity to customers in a safe and efficient manor while accommodating and complying with many stakeholders, codes and regulations. The ongoing trend to improve business standards and processes results in the development of better techniques. PUC makes use of these improvements to ensure that it is taking advantage of "best practice" information shared throughout the industry.

Activities at PUC are fundamentally driven by the direction of the OEB and its mandates and vision. The OEB continues to focus on increasing customer value and prudent system planning as provided in the Renewed Regulatory Framework for Electricity Distributors ("RRFE"). In general, PUC has maintained costs while accommodating higher standards, best practice, and ongoing change within the inflationary parameters since the last COS application.

For 2022 and 2023 budgeted OM&A expenses, PUC incorporated inflationary increases for unionized labour per collective agreements of 2%, Executive and Management labour increases per PUC's management compensation policy and other non labour items at a general inflation rate of 3%. Other than these inflationary items, additional OM&A expenses include costs for SSG, increased IT and regulatory expenses, increases in maintenance of equipment, and increases due to updates to the Shared Services Cost Allocation Model.

PUC recognizes that the Input Price Index ("IPI") effective for a rate application in 2022 is 3.3%. PUC expects the IPI to increase further in 2023 to above 7.7%[1] (CPI May 2021 to May 2022). Given the uncertainty surrounding the impact of rising inflation rates, PUC notes this will require further assessment during the proceeding as the situation evolves.

Table 4-3 below shows the historical inflationary OM&A increases using OEB approved inflation less PUC's productivity factor of 0.30%. The total increase from 2022 to 2023 Test Year due to inflation is $447,630.

Table 4-3: OM&A Inflation Trend Comparison

	2018 Board Approved	2019 inflationary	2020 inflationary	2021 inflationary	2022 inflatonary	2023 inflationary
OM&A	$11,176,156	$11,293,505	$11,468,555	$11,686,457	$12,037,051	$12,927,793
OEB Inflation (Less Productivity)		1.05%	1.55%	1.90%	3.00%	7.40%
2023 Revenue at Existing Rates Allocation in Proportion to 2018 Approved						$12,480,163
		Increase in OM&A due to inflation				**$447,630**

As shown in Table 4-4, OM&A expenses have increased from the 2018 Approved amount of $11,176,156 to the request of $13,533,701 in the 2023 Test year. This equates to a compound

[1] Consumer Price Index, monthly, not seasonally adjusted (statcan.gc.ca) as of July 2022

annual growth rate ("CAGR") of 3.9%. Despite business environment pressures, PUC's OM&A expenses have tracked to inflation increases from 2019 to 2022. A number of new costs over the cost-of-service period have increased costs in the 2023 Test Year request approximately 1.30% above inflation (IPI less productivity factor). The new OM&A costs are discussed further in this Exhibit.

Table 4-4: Actual/Forecast OM&A

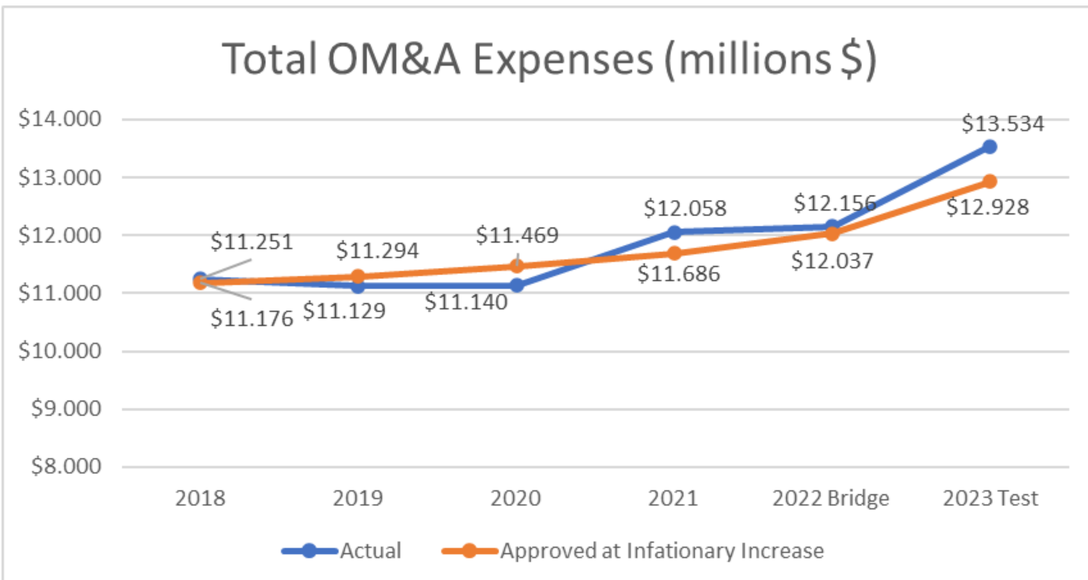
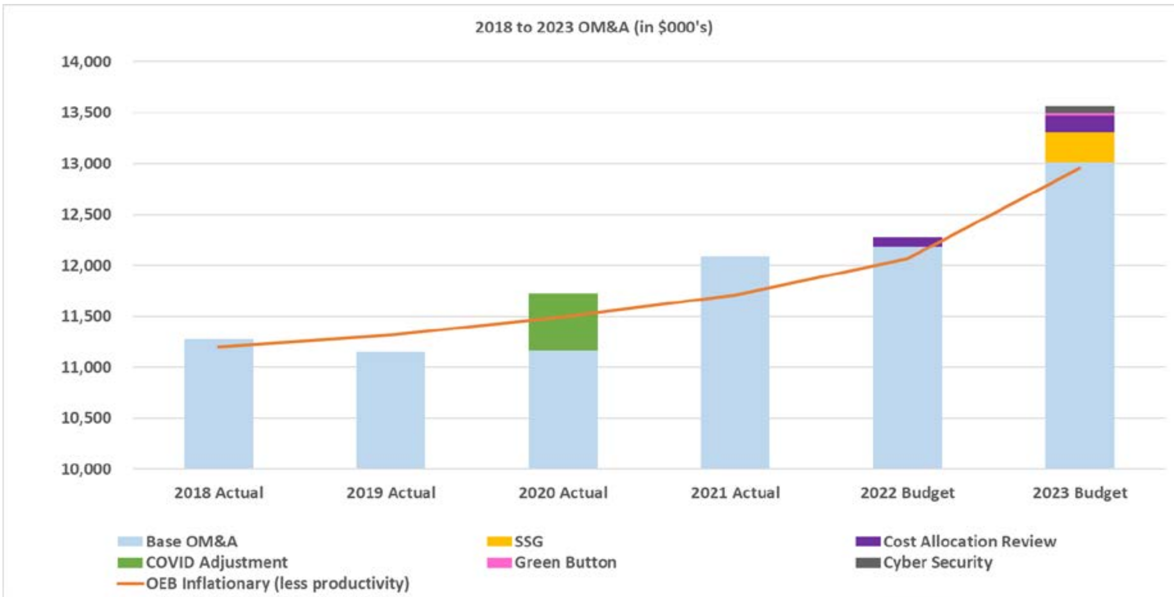


Table 4-5 shows PUC's trend in actual OM&A costs with the 2022 Bridge year and 2023 Test year as compared to OEB's IRM formula (inflation less productivity factor).

Table 4-5: 2018 Actual to 2023 Test Year Inflation Comparison



Overall PUC's OM&A has remained close to the OEB's IRM increases while navigating the COVID-19 pandemic impacts in 2020 and 2021. The slight increase in 2020 is due to COVID related costs that PUC is not seeking recovery for as it was reversed in 2021.

In the 2022 Bridge year, there is an increase in costs due to reallocation of shared costs following a tendered, detailed, independent, third-party cost allocation review completed by BDR North America ("BDR"). This review, lead by Paula Zarnett at BDR, was an update to the report from RDI Consulting Inc. that was filed with PUC's 2018 COS rate application. Overall, BDR's review supported the historical methodology used by PUC with updates to current payroll data for time studies and direct charges. This resulted in a slight increase in costs being allocated to PUC. The full cost allocation review report is discussed further below.

For the 2023 Test year, PUC included the increased costs from the cost allocation review, as well as incremental OM&A arising from the SSG. In addition, PUC is managing incremental costs and resources arising from other priority requirements including its Green Button implementation, Cyber Security and additional performance benchmarking activities. Green Button incremental initiative costs for 2022 have been recorded in the generic Account 1508 Deferral Account, however, PUC has included costs in OM&A for the 2023 Test year. The result is 2023 OM&A costs that are slightly above the IRM formula.

PUC continues to prudently manage OM&A costs and in 2020 PUC moved from the Group IV to the Group III cohort in the Pacific Economics Group Research ("PEG") report. The distributors in lower cohorts get rate reduction adjustments to recognize cost efficiency improvements, which in turn leads to lower distribution costs and rates. PUC assumed it would remain in the Group III cohort for purposes of this Application.

The OM&A per customer is provided in table 4-14. It breaks down the O&M per customer and Admin per customer. The following Table 4-6 shows the trend in changes to OM&A per component from the 2018 Board Approved through 2023 Test Year.

Table 4-6 Trend in OM&A per customer

OM&A cost per customer	2018 Actuval vs 2018 Board Approved	2018 Actual vs 2019 Actual	2019 Actual vs 2020 Actual	2020 Actual vs 2021 Actual	2021 Actual Vs 2022 Bridge Year	2022 Bridge Year vs 2023 Test Year		5 Year Change	CAGR
O&M per customer	(2.1%)	2.6%	1.8%	(0.8%)	4.4%	8.7%		17.5%	3.3%
Admin per customer	4.0%	(4.4%)	(2.8%)	19.7%	(3.0%)	13.9%		22.9%	4.2%
Total OM&A per customer	0.6%	(0.6%)	(0.2%)	7.9%	0.9%	11.0%		19.9%	3.7%

Overall PUC is trending at a CAGR of 3.3% for O&M per customer and 4.2% for Admin per customer. This averages out to be a CAGR of 3.7% per customer which is below the inflationary CAGR of 3.9%.

4.1.5. Business Environment Changes

Since PUC's last rebasing in 2018, there have been a number of significant business environment changes impacting PUC's operating expenses. These changes include the COVID-19 pandemic, an aging workforce, and new rules and requirements implemented by the OEB and Ontario Government. The following are some of the impactful regulatory changes since 2018:

- Changes to the Customer Service Rules impacting the processes for collection of overdue accounts (EB-2017-0183, the OEB's "Review of Customer Service Rules" initiative);
- The implementation of the OEB's Cybersecurity Framework;
- The implementation of the Ontario Rebate for Electricity Consumers;
- The implementation of the Customer Choice initiative which allows smart metered Regulated Price Plan ("RPP") customers to select between Time of Use ("TOU") and Tiered pricing;
- Wind-down of the Conservation First Framework; and
- The administration of the COVID-19 Energy Assistance Program ("CEAP").

The COVID-19 pandemic created significant challenges in PUC's business environment, but PUC reacted quickly and took measures to ensure continued public and employee safety as well as continued excellent service to its customers. Some of these impacts and actions are summarized below:

- Where possible, PUC deployed staff in applicable roles to working from home. For those positions where this was not possible, PUC ensured appropriate safety equipment, facilities and protocols were in place. PUC introduced separate employee working pods to prevent cross departmental exposure and extended sick days to prevent the spread of COVID-19;

- Consistent with Ontario-wide trends summarized by IESO, PUC saw an increase in residential consumption in 2020, as many workers and families were home during school/business hours at certain points throughout the year. Changes to the consumption patterns and consumption levels of business customers were also impacted, particularly for smaller businesses by lock down orders throughout the pandemic; and
- Although PUC worked through the COVID-19 pandemic without stoppage, the pandemic and the ensuing lockdowns did result in some cost reductions in fiscal 2020. Examples include discretionary spending for items such as training and travel due to restrictions and safety protocols. These savings would have been offset by additional resources in other areas, such as splitting workers into separate vehicles on jobs and increases in billing time to adjust for government programs. PUC did track and allocate the costs related to COVID additional activities in the approved COVID-10 Deferral and Variance account in 2020 and subsequently reversed these costs in 2021 based the guidance issued by the OEB in June 2021. In this respect, PUC acknowledges that the COVID-19 pandemic had to be taken into consideration while reviewing historical actual results presented in this Exhibit for the 2020 and 2021 fiscal years as they are not typical years.

With respect to an aging workforce, PUC has seen a number of retirements in key roles over the past several years. Since 2018, there have been 43 retirements in PUCS relative to the typical headcount of 171 positions, with an estimated 48% or 21 FTEs related directly to PUC.

As a strategic initiative, PUC is working to prepare a gap analysis which will identify the skillsets required to fill key roles within its organization. Once complete, a talent strategy will be developed and implemented which will focus on innovative opportunities to address future gaps through internal and external resources. A leadership development program is also being implemented to address the skills sets identified through the gap analysis so PUC can find opportunities to mentor and train internal resources for potential future promotion opportunities.

4.2. OM&A SUMMARY AND COST DRIVER TABLES

PUC follows the OEB's Accounting Procedures Handbook ("APH") in categorizing work performed between operations and maintenance. A summary of PUC's OM&A expenses for the 2018 Board Approved, 2018 Actual, 2019 Actual, 2020 Actual, 2021 Actual, 2022 Bridge Year and 2023 Test Year is provided in Table 4-7 – OM&A Summary (Board Appendix 2-JA) below, which is OEB's model live excel file, "PUC_2023_Filing_Requirements_Chapter 2, Appendices, Tab App.2.JA_OM&A_Summary Analysis". PUC notes, with respect to Appendix 2-JA, when it reviewed the prepopulated historical actual costs in the OEB Chapter 2 Appendices model that was made available to the 2023 Cost of Service filers, PUC identified a difference between the total aggregate OM&A costs filed in its annual 2.1.7 RRR Trial Balance each year as compared to the pre-populated aggregate OM&A in the model. PUC made adjustments to align to allocations between specific general ledger accounts to make them consistent with the allocations being used for the 2022 Bridge Year and the 2023 Test Year. These variances were due to the exclusion of Account 4815 – Station Buildings and Fixture expenses included in RRR and inclusion of LEAP amounts in RRR. The total variances are not material at +/- $20,000.

Table 4-7: Summary of Recoverable OM&A Expenses (Board Appendix 2-JA)

	2018 Last Rebasing Year OEB Approved	2018 Last Rebasing Year Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Operations	$ 4,029,899	$ 3,679,895	$ 4,151,756	$ 4,074,970	$ 3,935,625	$ 4,028,374	$ 4,434,334
Maintenance	$ 2,106,659	$ 2,329,918	$ 2,150,490	$ 2,359,394	$ 2,471,213	$ 2,652,070	$ 2,846,131
SubTotal	**$ 6,136,558**	**$ 6,009,813**	**$ 6,302,246**	**$ 6,434,364**	**$ 6,406,837**	**$ 6,680,445**	**$ 7,280,465**
%Change (year over year)		-2.1%	4.9%	2.1%	-0.4%	4.3%	9.0%
%Change (Test Year vs Last Rebasing Year - Actual)							21.1%
Billing and Collecting	$ 1,416,684	$ 1,381,283	$ 1,354,435	$ 1,333,216	$ 1,370,350	$ 1,237,795	$ 1,290,441
Community Relations	$ 620,355	$ 595,226	$ 640,859	$ 574,049	$ 635,277	$ 697,054	$ 753,359
Administrative and General	$ 3,002,559	$ 3,264,474	$ 2,831,111	$ 2,798,172	$ 3,645,134	$ 3,540,744	$ 4,209,436
SubTotal	**$ 5,039,598**	**$ 5,240,984**	**$ 4,826,405**	**$ 4,705,436**	**$ 5,650,761**	**$ 5,475,593**	**$ 6,253,236**
%Change (year over year)		4.0%	-7.9%	-2.5%	20.1%	-3.1%	14.2%
%Change (Test Year vs Last Rebasing Year - Actual)							19.3%
Total	**$ 11,176,156**	**$ 11,250,796**	**$ 11,128,652**	**$ 11,139,800**	**$ 12,057,598**	**$ 12,156,038**	**$ 13,533,701**
%Change (year over year)		0.7%	-1.1%	0.1%	8.2%	0.8%	11.3%

	2018 Last Rebasing Year OEB Approved	2018 Last Rebasing Year Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year	Variance 2022 Brdige Approved vs. 2023 Test Year	Variance %
Operations	$ 4,029,899	$ 3,679,895	$ 4,151,756	$ 4,074,970	$ 3,935,625	$ 4,028,374	$ 4,434,334	$ 405,960	10.1%
Maintenance	$ 2,106,659	$ 2,329,918	$ 2,150,490	$ 2,359,394	$ 2,471,213	$ 2,652,070	$ 2,846,131	$ 194,060	7.3%
Billing and Collecting	$ 1,416,684	$ 1,381,283	$ 1,354,435	$ 1,333,216	$ 1,370,350	$ 1,237,795	$ 1,290,441	$ 52,646	4.3%
Community Relations	$ 620,355	$ 595,226	$ 640,859	$ 574,049	$ 635,277	$ 697,054	$ 753,359	$ 56,305	8.1%
Administrative and General	$ 3,002,559	$ 3,264,474	$ 2,831,111	$ 2,798,172	$ 3,645,134	$ 3,540,744	$ 4,209,436	$ 668,692	18.9%
Total	**$ 11,176,156**	**$ 11,250,796**	**$ 11,128,652**	**$ 11,139,800**	**$ 12,057,598**	**$ 12,156,038**	**$ 13,533,701**	**$ 1,377,663**	**11.3%**
%Change (year over year)		0.7%	-1.1%	0.1%	8.2%	0.8%	11.3%	$ 2,357,545	**21.1%**

	Last Rebasing Year 2018 OEB Approved	Last Rebasing Year 2018 Actuals	Variance 2018 OEB Approved - 2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	Variance 2022 Bridge vs. 2021 Actuals	2023 Test Year	Variance 2023 Test vs. 2022 Bridge
Operations	$ 4,029,899	$ 3,679,895	$ 350,004	$ 4,151,756	$ 4,074,970	$ 3,935,625	$ 4,028,374	$ 92,750	$ 4,434,334	**$ 405,960**
Maintenance	$ 2,106,659	$ 2,329,918	-$ 223,259	$ 2,150,490	$ 2,359,394	$ 2,471,213	$ 2,652,070	$ 180,858	$ 2,901,131	**$ 249,061**
Billing and Collecting	$ 1,416,684	$ 1,381,283	$ 35,401	$ 1,354,435	$ 1,333,216	$ 1,370,350	$ 1,237,795	-$ 132,555	$ 1,290,441	**$ 52,646**
Community Relations	$ 620,355	$ 595,226	$ 25,128	$ 640,859	$ 574,049	$ 635,277	$ 697,054	$ 61,777	$ 753,359	**$ 56,305**
Administrative and General	$ 3,002,559	$ 3,264,474	-$ 261,915	$ 2,831,111	$ 2,798,172	$ 3,645,134	$ 3,540,744	-$ 104,390	$ 4,154,436	**$ 613,692**
Total OM&A Expenses	**$ 11,176,156**	**$ 11,250,796**	**-$ 74,640**	**$ 11,128,652**	**$ 11,139,800**	**$ 12,057,598**	**$ 12,156,038**	**$ 98,440**	**$ 13,533,701**	**$ 1,377,663**
Adjustments for Total non-recoverable items3										
Total Recoverable OM&A Expenses	**$ 11,176,156**	**$ 11,250,796**	**-$ 74,640**	**$ 11,128,652**	**$ 11,139,800**	**$ 12,057,598**	**$ 12,156,038**	**$ 98,440**	**$ 13,533,701**	**$ 1,377,663**
Variance from previous year				-$ 122,145	$ 11,148	$ 917,798	$ 98,440		$ 1,377,663	
Percent change (year over year)				0.0%	0.1%	8.2%	0.8%		11.3%	
Percent Change: Test year vs. Most Current Actual									12.24%	
Simple average of % variance for all years									5.12%	
Compound Annual Growth Rate for all years										3.8%
Compound Growth Rate (2021 vs. 2018 Actuals)									2.34%	

2023 Test Year OM&A expenditures are 21.1% higher than 2018 OEB Approved levels. The primary reason for this increase is inflation impacts on labour and non-labour costs, as well as higher levels of general administration costs in support of work programs and increased costs in support of the expanding asset base. Also included are the costs of new initiatives in support of PUC's strategic direction, infrastructure development, staff resourcing, and new systems, most notably for Cybersecurity risk mitigation. More detailed explanations for the overall increases from 2018-2023, and material year-over-year increases in OM&A, are provided below.

Some initiatives are planned to start in 2023 and as such, the 2023 Test Year OM&A is $1,377,663 (11.30%) higher than the 2022 Bridge Year. This increase is mainly due to operational staffing in support of the SSG, a Regulatory Analyst position to assist with increasing regulatory requirements such as Green Button and Activity Performance Based Benchmarking, an IT Analyst position to meet increasing information and cyber security requirements, and increased costs resulting from the updated Shared Services Cost Allocation Review.

Excluding the new incremental items noted above, the increase from 2022 to 2023 in OM&A expenses requested is comparable to the projected inflationary increase.

Consistent with the Board's Appendix 2-JB, Table 4-8 provides a list of the cost drivers that affected year-over-year OM&A spending or, where the cost driver is common or recurring, expenditures that have an impact across multiple years. Refer to the provided OEB model live excel file, "PUC_2023_Filing_Requirements_Chapter 2, Appendices, Tab App.2.JB_OM&A_Cost_Drivers".

<u>Table 4-8: Recoverable OM&A Cost Driver Table (Board Appendix 2-JB)</u>

OM&A	Last Rebasing Year (2018 Actuals)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Opening Balance	$ 11,474,633	$ 11,250,796	$ 11,128,652	$ 11,139,800	$ 12,057,598	$ 12,156,038
Property taxes moved from Acct 5675 to Acct 6105	($298,477)					
Adjusted Opening Balance	$ 11,176,156					
PCB Program (5010)			$ 293,015	$ (245,640)		
Load Dispatching (5035)						$ 116,742
General Admin Salary/Hourly Labour (5615)			$ 748,251		$ (700,711)	$ 131,507
Covid Allocation			$ (805,463)	$ 805,463		
Distribution Station Equip (5114)					$ 144,762	
ROW Tree Trim (5135)				$ 234,011		
Management Salaries & Expenses (5610)					$ 267,400	$ 144,913
Admn Off Alloc Com Mt SW (5620)					$ 140,794	
Regulatory expenses (5655)						$ 252,254
Includes general Inflationary increase and Items below materiality	$ 74,640	$ (122,145)	$ (224,655)	$ 123,964	$ 246,195	$ 732,248
Closing Balance	$ 11,250,796	$ 11,128,652	$ 11,139,800	$ 12,057,598	$ 12,156,038	$ 13,533,701

2023 Test Year OM&A costs of $13,533,701 are $2,357,545 (21.1%) higher than the 2018 OEB Approved amount. In general, for each driver, cost increases and decreases on a year-over-year basis throughout the 2018 to 2023 period are due to inflationary and/or below the materiality threshold. The primary drivers identified relate to timing differences on the execution of work, changing priorities, new initiatives and general escalations. The following discusses the material changes in the 2023 Test Year compared to the 2018 OEB Approved levels by primary driver. The following explanations detail the primary cost drivers that have influenced the increase in PUC's OM&A Expenditures since the last Cost of Service Application, up to and including the 2023 Test Year. Each cost driver is summarized by its net change year-over-year. PUC has provided comments on variances greater than its materiality level of $135,000.

<u>2019 Actual to 2020 Actual</u>

- PCB program – *increase of $293,015*

  Environment and Climate Change Canada issued the PCB Regulations (SOR/2008-273) which came into force on September 5, 2008. Regulation strictly states deadlines as to when specific assets containing PCB's exceeding specific concentration limits must be removed and properly disposed of. Pole-top electrical transformers containing PCBs in a concentration of 50 mg/kg, or more are to be removed from service before December 31, 2025. PUC's original estimate required 1,845 transformers to be tested. In 2020, a substantial portion (89%) of PCB transformer testing was completed, with the remaining testing to occur in 2021 (603) and 2022 (204).

- General Admin Salary and Hourly Labour – *increase of $748,251*

  The increase in 2020 was due to COVID related activities requiring more time to ensure the safety of customers and employees while maintaining stable operations. In 2020, this combined with a COVID allocation of $805,463 that was recorded to the COVID Deferral/Variance Account ("COVID DVA"), resulting in a net change of *$57,212*.

- COVID Allocation – *decrease of $805,463*

In its March 25, 2020 letter[2] ("Accounting Order"), the OEB acknowledged that electricity distributors may incur incremental costs as a result of the ongoing COVID-19 pandemic. The Accounting Order established a new COVID DVA, together with three sub-accounts, for electricity distributors to use to track incremental costs and lost revenues related to the pandemic. On May 14, 2020, the OEB issued a letter initiating the Consultation on the Deferral Account – Impacts Arising from the COVID-19 Emergency (the "Consultation") under OEB file number EB-2020-0133. As outlined in this letter, the objective of the Consultation was to assist the OEB in the development of new accounting guidance related to the COVID DVA and filing requirements, where appropriate, for the review and disposition of the account, giving due regard to bill impacts on customers. As a result of the documentation provided by the OEB, PUC Distribution recorded $805,463 of incremental COVID costs to the new COVID DVA.

2020 Actual to 2021 Actual

- PCB program – *decrease of $245,640*

This decrease is a result of a large portion of PCB transformer testing occurring in 2020. The variance between 2020 and 2021 is not material.

- COVID Allocation – *increase of $805,463*

[2] OEB Letter, March 25, 2020, Accounting Order for the Establishment of Deferral Accounts to Record Impacts Arising from the COVID-19 Emergency

On June 17, 2021[3], the OEB released the outcome of the Consultation titled “Regulatory Treatment of Impacts Arising from the COVID-19 Emergency” (the “Report”) which provided further guidance on use of the COVID DVA. Based on the guidance provided in the Report, some of PUC’s costs in the COVID DVA account were deemed ineligible for recovery and $805,463 was recognized as an expense in 2021.

- Right of Way – Tree Trimming – *increase of $234,011*

Line clearing costs in 2021 were $234,011 higher than the 2020 spending. The 2020 actual costs were at a lower level due to the reduced area cleared in 2020. In addition, extra unplanned work in rural areas and rear lot clearing was completed in response to forced outages that occurred early in the year.

<u>2021 Actual to 2022 Bridge</u>

- General Admin Salary and Hourly Labour – *decrease of $700,711*

The decrease in 2021 was due to the COVID reversal adjustment recorded to the DVA account in 2020.

- Distribution Station Equipment – *increase of $144,762*

PUCS added an additional Systems Operation Engineer position in support of the Sault Smart Grid project.

- Management Salary and Expenses – *increase of $267,400*

[3] OEB Report, June 17, 2021, Regulatory Treatment of Impacts Arising from the COVID-19 Emergency (EB-2020-0133)

PUCS added a shared resource position of Vice President of Corporate Services. In addition, there is a part-year impact of other shared resources including Director of Innovation and Technology and Information Security Analyst added as a result of increasing demands over information systems and cybersecurity requirements.

- Admin Software – *increase of $140,794*

There are two drivers for the increase in admin software. As a result of the COVID-19 pandemic, PUC converted some manual processes over to electronic/digital processes, resulting in increased software maintenance costs. In addition, as a result of the newly created Information Security department, there are additional software costs.

<u>2022 Bridge to 2023 Test Year</u>

- Load Dispatching – *increase $116,742*

PUCS has added an additional System Operator position in support of SSG.

- General & Admin Salaries and Expenses – *increase of $131,507*

PUCS has added additional shared resource positions for a Technical Accountant, as well as an IT Analyst position described above.

- Management Salary and Expenses – *increase of $144,913*

In 2022, PUCS added shared resource positions of Director of Innovation and Technology and Information Security Analyst as a result of increasing demands over information systems and cybersecurity requirements.

- Regulatory Expenses – *increase of $252,254*

PUC's estimated costs to prepare its 2023 COS application are $680,000, which amortized over 5 years for cost recovery is $136,000 per year. PUC's last COS totalled $578,788 in expenditures. PUC has put significant effort and attention towards minimizing the use of consultants and legal advisors to the greatest extent possible to limit the burden of costs on its ratepayers. The 2023 COS application cost estimates are provided below:

Table 4-9: 2023 COS Application Cost Estimates

Cost of Service Application Costs	Total COS	Amortized over 5 Years
Incremental operating expenses associated with staff resources allocated to this application.	$ 126,366	$ 25,273
Consultants' costs (legal, DSP, Shared Services, LRAM)	$ 430,634	$ 86,127
Intervenor costs (4)	$ 100,000	$ 20,000
OEB application costs	$ 20,000	$ 4,000
Settlement conference costs (virtual)	$ 3,000	$ 600
	$ 680,000	**$ 136,000**

In addition to the above COS costs, PUC has added an additional Regulatory Analyst. PUC currently has one dedicated Regulatory Analyst and assistance from PUCS is provided as required. Due to an increase in regulatory requirements, PUC has added an additional Analyst dedicated to ensuring reporting and compliance requirements are met.

- General inflation and items below materiality – *increase $732,248*

The general inflation and items below materiality include OM&A costs at the 2023 Test Year inflationary factors plus specific identified expense increases. Items that did not exceed the materiality threshold for explanations above include increased hardware/software maintenance fees, insurance, and building maintenance.

4.3. OM&A VARIANCE ANALYSIS

PUC has a variety of programs, activities and initiatives that are imperative to provide safe, reliable and affordable service to customers. In Table 4-10 below, PUC has identified its programs and major functions on a comparative basis from the 2018 Board Approved to the 2023 Test Year. The Uniform Standard of Accounts ("USoA") included in each program is defined as follows:

- Operations – UsoA accounts 5005, 5010, 5012, 5014, 5016, 5017, 5020, 5025, 5030, 5035, 5040, 5045, 5050, 5055, 5065, 5070, 5075, 5085, 5090, 5095, 5096
- Maintenance – UsoA accounts 5105, 5110, 5112 5114, 5120, 5125, 5130, 5135, 5145, 5150, 5155, 5160, 5175
- Customer Service – UsoA accounts 5305, 5310, 5315, 5320, 5325, 5335, 5405, 5410, 5420
- Administration – UsoA accounts 5605, 5610, 5620, 5630, 5635, 5655, 5665, 5675

Table 4-10 is consistent with the Boards Appendix 2-JC, refer to the provided OEB model live excel file, "PUC_2023_Filing_Requirements_Chapter 2, Appendices, Tab App.2.JC_OM&A_Programs". These programs contribute to achieving the RRFE performance outcomes of Customer Focus, Operational Effectiveness, and Public Policy Responsiveness. This shows the alignment of PUC's direct costs and the management of costs associated with the outcomes. An analysis is provided below on all material variances that exceed the materiality threshold for the 2023 Test Year versus the 2021 Actuals, and the 2023 Test Year versus the 2018 Board Approved amounts.

Table 4-10: OM&A Programs Table (Board Appendix 2-JC)

Programs	Last Rebasing Year (2018 OEB-Approved)	Last Rebasing Year (2018 Actuals)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year	Variance (Test Year vs. 2021 Actuals)	Variance (Test Year vs. Last Rebasing Year (2018 OEB-Approved)
Operations									
Overhead Lines	$ 865,472	$ 905,827	$ 980,204	$ 1,211,054	$ 887,684	$ 877,981	$ 919,013	$ 31,329	$ 53,541
Underground Lines	$ 204,062	$ 244,518	$ 306,103	$ 211,298	$ 267,536	$ 258,944	$ 273,313	$ 5,778	$ 69,251
Operations Supervisory	$ 645,671	$ 513,871	$ 544,133	$ 467,519	$ 527,210	$ 572,525	$ 601,703	$ 74,492	$ (43,969)
Load Dispatching	$ 273,568	$ 246,072	$ 385,248	$ 299,920	$ 322,436	$ 255,743	$ 426,985	$ 104,549	$ 153,417
Stations	$ 789,639	$ 730,287	$ 770,038	$ 695,028	$ 703,762	$ 729,968	$ 815,449	$ 111,687	$ 25,810
Transformers	$ 8,240	$ 8,044	$ 11,541	$ 7,852	$ 9,797	$ 9,883	$ 10,343	$ 547	$ 2,103
Meters	$ 403,539	$ 303,712	$ 265,723	$ 240,866	$ 243,208	$ 281,143	$ 323,047	$ 79,839	$ (80,492)
Transmission	$ 83,575	$ 48,749	$ 10,814	$ 13,034	$ 13,138	$ 15,272	$ 43,095	$ 29,958	$ (40,479)
Customer Premises	$ 179,701	$ 162,557	$ 205,855	$ 257,028	$ 281,306	$ 281,252	$ 295,150	$ 13,844	$ 115,449
Miscellaneous Operating	$ 576,433	$ 516,257	$ 672,098	$ 671,369	$ 679,547	$ 745,664	$ 726,236	$ 46,689	$ 149,803
Sub-Total	**$ 4,029,899**	**$ 3,679,895**	**$ 4,151,756**	**$ 4,074,970**	**$ 3,935,625**	**$ 4,028,374**	**$ 4,434,334**	**$ 498,710**	**$ 404,435**
Maintenance									
Overhead Lines	$ 1,368,590	$ 1,458,744	$ 1,453,317	$ 1,508,988	$ 1,611,173	$ 1,638,828	$ 1,744,789	$ 133,616	$ 376,200
Underground Lines	$ 304,604	$ 369,510	$ 282,312	$ 265,172	$ 337,579	$ 302,287	$ 316,493	$ (21,086)	$ 11,889
Stations	$ 259,555	$ 400,136	$ 295,119	$ 471,194	$ 441,663	$ 606,200	$ 705,303	$ 263,640	$ 445,748
Transformers	$ 121,580	$ 38,617	$ 22,485	$ 35,790	$ 16,138	$ 62,673	$ 84,812	$ 68,674	$ (36,768)
Meters	$ 52,330	$ 62,912	$ 97,257	$ 78,250	$ 64,659	$ 42,082	$ 49,733	$ (14,926)	$ (2,597)
Sub-Total	**$ 2,106,659**	**$ 2,329,918**	**$ 2,150,490**	**$ 2,359,394**	**$ 2,471,213**	**$ 2,652,070**	**$ 2,901,131**	**$ 429,918**	**$ 794,472**
Customer Service									
Bad Debt Expense	$ 262,223	$ 249,235	$ 252,481	$ 354,697	$ 366,554	$ 300,000	$ 350,000	$ (16,554)	$ 87,777
Customer Billing	$ 877,623	$ 810,496	$ 857,977	$ 775,162	$ 828,810	$ 782,769	$ 779,893	$ (48,917)	$ (97,731)
Customer Collections	$ 276,838	$ 321,552	$ 243,977	$ 203,358	$ 174,986	$ 155,026	$ 160,548	$ (14,438)	$ (116,289)
Community Relations	$ 620,355	$ 595,226	$ 640,859	$ 574,049	$ 635,277	$ 697,054	$ 753,359	$ 118,083	$ 133,005
Sub-Total	**$ 2,037,039**	**$ 1,976,509**	**$ 1,995,295**	**$ 1,907,265**	**$ 2,005,626**	**$ 1,934,849**	**$ 2,043,800**	**$ 38,174**	**$ 6,762**
Administration									
Insurance	$ 100,220	$ 160,140	$ 155,870	$ 159,899	$ 160,592	$ 160,279	$ 177,653	$ 17,060	$ 77,433
Audit, Legal & Consulting	$ 209,877	$ 202,488	$ 184,269	$ 297,996	$ 175,828	$ 269,334	$ 238,891	$ 63,063	$ 29,014
Regulatory Affairs	$ 406,157	$ 804,051	$ 319,679	$ 279,079	$ 274,354	$ 349,944	$ 536,858	$ 262,504	$ 130,702
Building	$ 417,253	$ 337,731	$ 351,249	$ 319,987	$ 333,356	$ 388,823	$ 389,410	$ 56,055	$ (27,843)
Administrative	$ 1,869,053	$ 1,760,065	$ 1,820,044	$ 1,741,211	$ 2,701,004	$ 2,372,365	$ 2,811,623	$ 110,619	$ 942,571
Sub-Total	**$ 3,002,559**	**$ 3,264,474**	**$ 2,831,111**	**$ 2,798,172**	**$ 3,645,134**	**$ 3,540,744**	**$ 4,154,436**	**$ 509,301**	**$ 1,151,876**
Total	**$ 11,176,156**	**$ 11,250,796**	**$ 11,128,652**	**$ 11,139,800**	**$ 12,057,598**	**$ 12,156,038**	**$ 13,533,701**	**$ 1,476,103**	**$ 2,357,545**

In accordance with Chapter 2 Filing Requirements, an applicant must provide justification for changes from year-to-year to its rate base, capital expenditures and OM&A spending above a materiality threshold. PUC's materiality threshold is calculated as 0.5% of proposed base distribution revenue requirement for distributors with a revenue requirement greater than $10 million and less than or equal to $200 million. As such, PUC has calculated and used a threshold of $135,000 for variance analysis purposes.

PUC has provided explanations below for material variances for the Historical OEB-Approved vs Historical Actual (for the most recent Historical OEB-Approved year), the 2023 Test Year vs 2018 Board Approved levels and the 2023 Test Year vs the most historic year Actuals (2021) for program delivery costs. Variances, for the most part have been in PUC's control, e.g., increased due to the operation of SGG. Other costs outside of PUC's control are due to inflationary increases.

- Operations - Load Dispatching

  2023 Test Year vs 2018 Approved – *$153,417*

  PUC has added an additional System Operator position in support of SSG.

- Operations - Miscellaneous Operating

  2023 Test Year vs 2018 Approved – *$149,803*

  Increases in miscellaneous operating costs from 2018 Approved to the 2023 Test year include:

  - Increase in labour costs as a result of an additional Electrical Engineer in support of SSG.
  - Increased GIS costs.
  - Inflationary increases for wages and external expenses.

- Maintenance Overhead Lines

  2023 Test Year vs 2018 Approved – *$376,200*

  PUC experienced a shift in the amount of expenses in maintenance overhead line from 2018 Board Approved to 2023 Test Year. The increase is a result of additional labour, materials, trucking, and external contractor costs allocated to these OM&A accounts, in 2023, as compared to the 2018 Board Approved amounts.

- Maintenance - Stations

  2023 Test Year vs 2021 Actuals - $263,640

  Increases in station maintenance costs from 2021 Actuals to the 2023 Test year include:

  - The addition of a System Operations Engineer position in support of SSG.

  - The shift of labour from capital to maintenance. In 2021, extensive resources were directed to capital work for the Substation 16 re-build which decreased the allocation of labour charged to station operations and maintenance accounts.
  - To plan for the retirement of 2 substations, an additional $40,000 was added for environmental remediation work.
  - Inflationary increases for wages and external expenses.

  2023 Test Year vs 2018 Approved - *$445,748*

  Increases in station maintenance costs from 2018 Approved to the 2023 Test year include:

  - PUC Distribution added an additional System Operations Engineer position in support of SSG.

- o Station maintenance work was reallocated to maintenance versus station operations. Stations operations reflects a minor increase of $25,810 from the last rebasing.
- o To plan for the retirement of 2 substations, an additional $40,000 was added for environmental remediation work.
- o The remainder of the increase was due to wage progressions, as well as inflationary increases for labour and external expenses.

- Regulatory Affairs

<u>2018 Board Approved vs 2018 Actual - $397,894</u>

The 2018 Board Approved amount was the 2018 Cost of Service Rate Application expenses amortized over five years as compared to the 2018 Actuals where the full amount was expensed.

<u>2023 Test Year vs 2021 Actuals - $262,504</u>

Increases in regulatory affairs costs from 2021 Actuals to the 2023 Test year include:

- o An additional Regulatory Analyst position to support the increasing regulatory requirements such as Green Button, Activity Based Performance benchmarking, and other OEB mandated programs and activity.
- o In 2023, PUC has included 1/5th of the 2023 COS application costs. These costs, to be incurred in 2022 and 2023, have been recorded in a prepaid account to be recognized as an expense over the 5-year rate-period. This accounting treatment is different than the 2018 COS application costs which were expensed in the year they occurred.
- o Inflationary increases for labour and external expenses.

2023 Test Year vs 2018 Approved - $130,702

Increases in regulatory affair costs from 2018 Approved to the 2023 Test year include:

- An additional Regulatory Analyst position to support the increasing regulatory requirements such as Green Button, Activity Based Performance benchmarking, and other OEB mandated programs and activity.
- An Assistant Controller position, added in 2019, supports PUC's regulatory affairs with advisory and oversight responsibilities.
- Inflationary increases for wages and external expenses.

- Administrative

2023 Test Year vs 2018 Approved - $942,571

Increases in administrative costs from 2018 Approved to the 2023 Test year include:

- Increase in software maintenance costs for electronic process updates including Green Button, MyPUC app, implementation of new payroll software (i.e., Dayforce), additional cyber security software and new software to support electronic process conversions including software for contractor management, accounts payable processing, and a new platform for electronic forms for PUC's operations group.
- In addition to inflationary increases to salaries and wages, PUCS added the following positions:

- Vice President, Corporate Services to ensure compliance with legislation, regulations and codes, develop and maintain emergency preparedness, response and contingency plans and provide leadership and expertise in formulating strategies, programs and policies for People & Culture, IT, Health & Safety, Fleet and Facilities. PUCS will be adding a Director of Innovation & Technology due to the increased demands on information systems, as well as an Information Security Analyst to manage electronic security and data for privacy requirements.
- Senior People & Culture Business partner to assist the Manager, People & Culture with recruitment and selection of new staff, training plans, and management of labour related matters.
- Assistant Controller in the Finance division to assist in managing compliance, internal controls, processes, and procedures.

o Increase in training and development costs.

o Inflationary increases for labour and external expenses.

4.3.1. Capitalized OM&A

The 2023 Test Year OM&A is after the transfer of "OM&A" costs charged to capital as part of the overhead capitalization rate. Table 4-11 summarizes these amounts.

Table 4-11: Capitalized OM&A

Capitalized OM&A	2018	2019	2020	2021	2022	2023
	Historical Year	Historical Year	Historical Year	Historical Year	Bridge Year	Test Year
Materials	$ 279,442	$ 269,319	$ 285,879	$ 361,731	$ 315,717	$ 322,032
Engineering	$ 400,223	$ 499,945	$ 524,173	$ 472,489	$ 904,430	$ 952,049
Trucking	$ 426,211	$ 437,547	$ 341,102	$ 351,519	$ 437,981	$ 495,152
Supervisory	$ 295,199	$ 341,910	$ 342,291	$ 285,571	$ 414,533	$ 319,596
Total Capitalized OM&A (A)	**$ 1,401,075**	**$ 1,548,723**	**$ 1,493,445**	**$ 1,471,310**	**$2,072,661**	**$2,088,829**

Capitalized OM&A in the 2023 Test Year is $16,168 higher than 2022 Bridge Year which is immaterial. The level of 2023 Test Year Capitalized OM&A is $601,351 higher than the 2020 Actual. This is due to an increase in capital initiatives, i.e., SSG.

4.3.2. Workforce Planning and Employee Compensation

4.3.2.1 Compensation System

PUC has a long-term service agreement with PUCS for the operation of its distribution system. PUC does not have employees, however, in addition to regular salaries and wages, PUCS offers the following compensation system to PUC equivalent employees:

Unionized Workers

Approximately 75% of PUC's workforce is unionized. The compensation for unionized employees is negotiated through the collective bargaining process and includes both office and trades workers represented by the Power Workers Union ("PWU"), Local CUPE 1000, in separate "Office Worker" and "Outside Worker" agreements.

PUCS's collective agreements provide for annual payroll increases and employee step progressions. Labour rates and benefits are adjusted based on negotiated percentages as per the collective agreement. The commencement and expiry dates of PUC's current collective agreements are shown in Table 4-12 Current Collective Agreements below.

Table 4-12: Current Collective Agreements

Bargaining Unit	Contract Period	Wage increase
PWU Office	May 1, 2021 to April 30, 2024	May 1, 2021: 2.0% May 1, 2022: 2.0% May 1, 2023: 2.0%
PWU Outside	May 1, 2021 to April 30, 2024	May 1, 2021: 2.0% May 1, 2022: 2.0% May 1, 2023: 2.0%

The collective agreement also includes a one-time cost of living adjustment.

Cost of Living Adjustment

If the average monthly CPI for Canada [Base 2002] for the twelve months ending December 31, 2021, is greater than CPI for Canada for the 12 months ending December 31, 2020, a one-time lump sum payment will be made prior to March 31, 2022 based on the following table:

Percentage Change in CPI	Payment as a percent of Gross Earnings from Jan 1, 2021 – Dec. 31, 2021
>=3.50<4.00	0.00
>=4.00<4.50	0.50
>=4.50<5.00	1.00
>5.00	1.50

Each job classification in the collective bargaining agreements has a basic job description and a wage rate progression scale that increases from a minimum to a maximum rate.

Executive and Management (Non-Union) Employees

PUCS's Executive and Management staff ("Management") pay philosophy considers compensation from throughout Ontario at other like-sized or similarly structured utilities, ensuring that Management staff are compensated at levels consistent with comparable organizations. Such compensation levels are reviewed on a regular basis and benchmarked against the MEARIE Group Management Salary Survey administered by Korn Ferry Hay Group. The Management group salaries, a portion of which are allocated to PUC, are at or near the average of the LDCs surveyed.

Specifically, compensation for the President & CEO is administered directly by the Board of Directors. Other Management compensation consists of salaries and benefits. Each Management position has been placed on a pay scale which is reviewed periodically by senior management. As with unionized employees, compensation for Management provides for annual payroll increases and employee step progressions upon approval by the President & CEO, with consideration of budgets that are approved by the Board of Directors.

Every three years a salary structure review is completed to compare the Management salary bands against a utility peer group to ensure compensation remains within the 50th percentile. Salary bands may be impacted by this review. For the intervening years between the salary structure reviews, adjustments are applied to the salary bands based on November CPI[4] for Ontario in accordance with the Management Compensation policy. These amounts are first reviewed and approved by the President & CEO. Table 4-13 below shows the annual increases from 2018 – 2022.

[4] Consumer Price Index, monthly, not seasonally adjusted (statcan.gc.ca)

Table 4-13: Management Salary Increases

Year	Wage Increase
2018	1.8%
2019	1.8%
2020	1.9%
2021	1.5%
2022	5.0%

Health Benefits

A comprehensive and competitive benefits package exists which includes medical and dental insurance, life insurance, vacation and leave policies and a company sponsored retirement pension plan. There are separate benefits plans for active Management, PWU, and retired employees.

The PWU and retiree benefit plans are subject to change during the collective bargaining process and the Management benefit plan is typically adjusted to mirror any negotiated improvements. The plans are designed to address the health and welfare needs of the employees. The benefit packages are essentially consistent across the employee groups for all 171 employees, including the executive team. Variations do exist within the life insurance coverages and health care spending accounts provided for non-unionized employees only.

OMERS Pension Plan

All PUCS employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan in which most Ontario LDCs participate. As such, PUCS pension benefit costs are consistent with other participating Ontario LDCs. While

OMERS is a Defined Benefit plan, for accounting purposes it is effectively treated as a Defined Contribution plan by the participating distributors including PUCS. This means that the annual employer contributions made to the plan are the same as the accrual accounting expense recorded for financial statement purposes. For the 2023 Test Year, PUC assumed OMERS rates of 9.0% on earnings up to the Year's Maximum Pensionable Earnings ("YMPE") limits and 14.6% on earnings over YMPE limits. The 2022 YMPE is $64,900.

Employee Future Benefits

PUCS provides post-employment benefit life insurance and health care to retirees under the age of 65 through a group defined benefit plan.

The cost of post-employment benefits is actuarially determined using the projected benefit method prorated on service and based on assumptions that reflect management 's best estimates. The current service cost for the period is equal to the employee's service rendered in the period. Past service costs from the plan amendments are amortized on a straight line basis over the average remaining service period of the employee's active date of amendment.
As noted above, PUC does not have employees, therefore an actuary report cannot be provided. The actuary report for PUCS has been provided in Appendix A.

PUCS recovers their Ontario Post Employment Benefits ("OPEB") costs based on the accrual method. This method recognizes the cost of OPEBs as an employee's service is rendered and the benefit is earned. PUC's shared portion of the accrued amount is allocated as an overhead on direct labour on an annual basis. As such, PUC's obligation for OPEBs is treated similar to pension funding where there are no future obligations.

4.3.2.2 Succession Planning

As part of a strategic initiative, PUCS has begun to implement a succession planning review and process. It continues to monitor key employee retirement eligibility and employee intentions where known, in order to plan for the necessary employee succession. PUC is working toward a gap analysis with will identify the skill sets required to fill key roles within the organization.
The following summarizes Management's plans regarding succession vulnerability:

<u>Powerline</u>

PUCS currently has a crew of qualified and experienced Powerline Technicians. PUC has a sufficient number of qualified and experienced Powerline Technicians and will utilize apprenticeship programs to ensure adequate ability to fill vacancies as they occur.

<u>Stations & Metering</u>

PUCS currently has a staff of qualified and experienced workers with some becoming eligible for retirement within the next five years. PUCS intends to utilize apprenticeship programs to ensure adequate ability to fill vacancies as they occur.

<u>Executive</u>

The senior management team has recruited key personnel in the past few years in response to and to successfully prepare for upcoming retirements.

4.3.2.3 Wages, Salaries and Benefit Expenses

Salaries, wages and benefits are the most significant drivers of PUC's 2023 Test Year OM&A costs and have a 26.1% increase from the 2018 Actual Year as shown in Table 4-14 below. PUC's complement has decreased by 1 FTE ("Full Time Equivalent") since the 2018 actual year; however, total salaries, wages and benefits have increased due to inflation and changes to positions as discussed above.

Table 4-14: Overall Compensation Trend Summary: 2018 Actual to 2023 Test Year

Description	2018 Actuals	2023 Test Year	Variance
FTE's	82	81	(1)
			-1.0%
Total Compensation (Salary, Wages and Benefits)	$ 10,279,952	$ 12,968,022	$ 2,688,069
			26.1%

The reduction in FTE is a result of the allocation of staff members' time to affiliate services. The relative increase in total compensation from 2018-2023 is primarily a result of annual increases to compensation. Wage increases for Unionized staff is in accordance with negotiated collective agreements. Adjustments for Management staff salaries are in accordance with PUCS's Management Compensation Policy, described above, in addition to adjustments for productivity, merit, and promotion.

Included in Table 4-14, which is Board Appendix 2-L, is a summary of OM&A Cost per Customer and per FTE. This table is consistent with the Boards Appendix 2-L, refer to the provided OEB model live excel file, "PUC_2023_Filing_Requirements_Chapter 2, Appendices, Tab App.2.JL_OM&A_per_Cust_FTE". The number of customers is based on the annual average for each rate class of metered customers.

Table 4-14: Recoverable OM&A Per Customer and FTE (Board Appendix 2-L)

	Last Rebasing Year (2018 OEB Approved)	Last Rebasing Year (2018 Actuals)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
OM&A Costs							
O&M	$ 6,136,558	$ 6,009,813	$ 6,302,246	$ 6,434,364	$ 6,406,837	$ 6,680,445	$ 7,335,465
Admin Expenses	$ 5,039,598	$ 5,240,983	$ 4,826,405	$ 4,705,436	$ 5,650,761	$ 5,475,593	$ 6,198,236
Total Recoverable OM&A from Appendix 2-JB	**$ 11,176,156**	**$ 11,250,796**	**$ 11,128,652**	**$ 11,139,800**	**$ 12,057,598**	**$ 12,156,038**	**$ 13,533,701**
Number of Customers	33,604	33,613	33,647	33,751	33,865	33,838	33,926
Number of FTEs	84	82	80	78	78	78	81
Customers/FTEs	399	411	421	431	434	434	419
OM&A cost per customer							
O&M per customer	$ 183	$ 179	$ 187	$ 191	$ 189	$ 197	$ 216
Admin per customer	$ 150	$ 156	$ 143	$ 139	$ 167	$ 162	$ 183
Total OM&A per customer	**$ 333**	**$ 335**	**$ 331**	**$ 330**	**$ 356**	**$ 359**	**$ 399**
OM&A cost per FTE							19.9%
O&M per FTE	$ 72,918	$ 73,434	$ 78,926	$ 82,144	$ 82,139	$ 85,647	$ 90,561
Admin per FTE	$ 59,884	$ 64,039	$ 60,443	$ 60,072	$ 72,446	$ 70,200	$ 76,521
Total OM&A per FTE	**$ 132,802**	**$ 137,473**	**$ 139,369**	**$ 142,216**	**$ 154,585**	**$ 155,847**	**$ 167,083**
% increase 2018 Approved to 2023 Test Year							25.8%

	Last Rebasing Year (2018 OEB Approved)	Last Rebasing Year (2018 Actuals)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
OEB Inflation less productivity			1.05%	1.55%	1.90%	3.00%	7.40%
Total OM&A per customer (adjusted for inflation)	$ 333	$ 335	$ 336	$ 341	$ 348	$ 358	$ 385
% increase 2018 Approved to 2023 Test Year							15.7%
Total OM&A per FTE (adjusted for inflation)	$ 132,802	$ 137,473	$ 134,196	$ 136,277	$ 138,866	$ 143,032	$ 153,616
% increase 2018 Approved to 2023 Test Year							15.7%

In 2023, OM&A per customer is forecast to be $399. This is 19.9% higher than the $333 OM&A per customer ratio in 2018. The OM&A costs per FTE are forecast to be $167,083. This is 25.8% higher than the $132,802 amount approved in 2018. PUC notes that these increases from 2018 to 2023 are primarily related to inflation. As shown in the bottom section of table above, inflationary adjustments account for a 15.7% impact to OM&A costs per customer and OM&A costs per FTE, which results in $153,616 and $385, respectively.

FTE & Employee Costs

As required, employee complement by FTE, compensation and benefits are set out below in Table 4-16. This table is consistent with the Boards Appendix 2-K, refer to the provided OEB model live excel file, "PUC_2023_Filing_Requirements_Chapter 2, Appendices, Tab App.2.K_Employee Costs".

Table 4-16: Employee Costs (Board Appendix 2-K)

	Last Rebasing Year (2018 OEB Approved)	Last Rebasing Year (2018 Actuals)	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge Year	2023 Test Year
Number of Employees (FTEs including Part-Time)							
Management (including executive)	19	19	18	18	21	21	23
Non-Management (union and non-union)	65	63	62	60	57	57	58
Total	84	82	80	78	78	78	81
Total Salary and Wages including ovetime and incentive pay							
Management (including executive)	$ 2,219,285	$ 2,278,502	$ 2,147,051	$ 2,214,608	$ 2,180,535	$ 2,078,341	$ 2,412,944
Non-Management (union and non-union)	$ 5,475,807	$ 4,962,742	$ 5,087,619	$ 5,127,371	$ 4,984,153	$ 4,654,346	$ 5,515,381
Total	$ 7,695,092	$ 7,241,244	$ 7,234,670	$ 7,341,979	$ 7,164,688	$ 6,732,687	$ 7,928,325
Total Benefits (Current + Accrued)							
Management (including executive)	$ 562,869	$ 700,251	$ 679,384	$ 743,763	$ 697,294	$ 1,165,100	$ 771,614
Non-Management (union and non-union)	$ 1,445,296	$ 1,414,382	$ 1,333,848	$ 1,324,607	$ 1,503,636	$ 1,520,535	$ 1,663,899
Total	$ 2,008,164	$ 2,114,633	$ 2,013,232	$ 2,068,370	$ 2,200,930	$ 2,685,635	$ 2,435,513
Total Compensation (Salary, Wages, & Benefits)							
Management (including executive)	$ 2,782,154	$ 2,978,753	$ 2,826,435	$ 2,958,371	$ 3,287,346	$ 3,590,621	$ 3,184,558
Non-Management (union and non-union)	$ 6,921,103	$ 6,377,124	$ 6,421,467	$ 6,451,977	$ 7,486,888	$ 8,177,594	$ 7,179,280
Total	$ 9,703,257	$ 9,355,877	$ 9,247,902	$ 9,410,349	$ 9,365,618	$ 9,418,322	$ 10,363,838
Total Compensation Breakdown (Capital, OM&A)							
OM&A		$ 7,135,221	$ 6,726,296	$ 7,140,599	$ 6,879,233	$ 6,274,588	$ 7,947,124
Capital		$ 2,219,656	$ 2,521,605	$ 2,269,750	$ 2,486,385	$ 3,143,734	$ 2,416,391
Total	$ -	$ 9,354,878	$ 9,247,901	$ 9,410,348	$ 9,365,618	$ 9,418,322	$ 10,363,515

PUC, through its affiliate PUCS operates using a shared services model. PUC has no employees but rather relies on PUCS to provide the necessary resources to operate the distribution utility. The number of employees shown above is based on the computation of the number of FTE positions throughout each of the fiscal years. Staff members hired by or resigning from PUCS are prorated in that year as a portion of an FTE based on the hours worked. The FTE calculation is based on hours worked by PUCS employees, including overtime hours that are directly and indirectly attributable to PUC. The table excludes Board of Directors and employees dedicated to non-rate regulated activities. PUC does not include hours for staff off on short term or long-term disability. The salaries and wages amounts include all salaries and wages paid, inclusive of incentive pay, overtime, vacation, holidays, sick leave, bereavement leave and other miscellaneous paid leaves.

The benefits amount comprises the employer's portion of statutory benefits, including CPP, EI, EHT and WSIB. In addition, benefit amounts include the company's cost for providing pension benefits ("OMERS") and other employee benefits as described below.

FTE, Wages & Benefits Variance Analysis

Table 4-17 details employee cost variances from 2018 Board Approved through to the 2023 Test Year. The year-to-year variances are due to fluctuations in allocations of PUCS employee resources. In addition, impacts from inflationary increases are included in the salaries, wages and benefits totals. The 2023 Test Year shows an increase due to the added positions explained above in the OM&A variance analysis, section 4.3 of this Exhibit.

Table 4-17: FTE and Employee Cost Variances

	2018 OEB Approved to 2018 Actual	2018 Actuals to 2019 Actuals	2019 Actuals to 2020 Actuals	2020 Actuals to 2021 Actuals	2021 Actuals to 2022 Bridge	2022 Bridge to 2023 Test
Number of Employees (FTEs including Part-Time)						
Management (including executive)	0	(1)	(0)	3	0	2
Non-Management (union and non-union)	(2)	(1)	(1)	(3)	0	1
Total	(2)	(2)	(2)	(0)	0	3
Total Salary and Wages including ovetime and incentive pay						
Management (including executive)	$ 59,217	$ (131,451)	$ 67,557	$ (34,073)	$ (102,194)	$ 334,603
Non-Management (union and non-union)	$ (513,065)	$ 124,877	$ 39,752	$ (143,218)	$ (329,807)	$ 861,035
Total	$ (453,848)	$ (6,574)	$ 107,309	$ (177,290)	$ (432,001)	$ 1,195,638
Total Benefits (Current + Accrued)						
Management (including executive)	$ 137,382	$ (20,867)	$ 64,379	$ (46,469)	$ 467,806	$ (393,486)
Non-Management (union and non-union)	$ (30,914)	$ (80,534)	$ (9,241)	$ 179,029	$ 16,899	$ 143,364
Total	$ 106,469	$ (101,401)	$ 55,138	$ 132,560	$ 484,705	$ (250,122)
Total Compensation (Salary, Wages, & Benefits)						
Management (including executive)	$ 196,599	$ (152,318)	$ 131,936	$ 328,974	$ 303,275	$ (406,063)
Non-Management (union and non-union)	$ (543,979)	$ 44,343	$ 30,510	$ 1,034,911	$ 690,706	$ (998,314)
Total	$ (347,379)	$ (107,975)	$ 162,447	$ (44,731)	$ 52,704	$ 945,516
Total Compensation Breakdown (Capital, OM&A)						
OM&A		$ (408,925)	$ 414,303	$ (261,366)	$ (604,645)	$ 1,672,536
Capital		$ 301,949	$ (251,855)	$ 216,636	$ 657,348	$ (727,343)
Total		$ (106,977)	$ 162,447	$ (44,730)	$ 52,704	$ 945,193

The FTE calculation is based on hours worked by PUCS employees, including overtime hours that are directly and indirectly attributable to PUC. These variations are also reflected in the variances between employee cost categories.

Both Management and Non-Management categories have experienced minor fluctuations since the last rebasing in 2018, with the exception of 2021 due to the impact of the COVID-19 adjustment, and in 2023 due to the additions of resources for SSG, IT and Regulatory.

Benefits, Pensions & Post-Retirement Benefits

Please refer to Table 4-17 for a summary of Benefit Historical details.

Table 4-17: Employee Benefit Costs

Benefit	2018 Last Rebasing	2018 Actuals	2019 Actuals	2020 Actuals	2021 Actuals	2022 Bridge	2023 Test
CPP Employers' Portion	$ 188,142	$ 174,462	$ 187,643	$ 192,284	$ 237,683	$ 300,592	$ 331,238
EI Employers' Portion	$ 67,036	$ 77,083	$ 71,482	$ 71,818	$ 79,424	$ 100,446	$ 110,687
Employer Health Tax	$ 117,218	$ 116,266	$ 118,991	$ 120,618	$ 139,312	$ 176,184	$ 194,147
WSIB	$ 57,110	$ 67,224	$ 55,534	$ 63,614	$ 70,925	$ 89,697	$ 98,842
OMERS Employers' Portion	$ 591,221	$ 581,078	$ 618,817	$ 651,832	$ 692,231	$ 875,447	$ 964,701
OPEB	$ -	$ 42,183	$ 34,150	$ 48,978	$ 44,053	$ 55,713	$ 61,393
Corporate Benefits	$ 531,880	$ 751,427	$ 737,866	$ 646,635	$ 827,387	$ 1,046,375	$ 1,153,056
Total Benefits Charged to OM&A	**$ 1,552,607**	**$ 1,809,722**	**$ 1,824,483**	**$ 1,795,780**	**$ 2,091,015**	**$ 2,644,454**	**$ 2,914,064**

Benefit Program Costs

As noted below, PUC is a virtual utility, however, for COS filing requirements, PUC has determined the details of employee benefit programs breakdown above using the shared services allocation methodology described in section 4.3.3. For 2022 Bridge and 2023 Test years amounts have been forecasted using a 5% increase on prior year amounts.

OMERs Pension Plan

PUCS' employees are members of the Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan that most LDC's participate in, therefore the pension benefit provided to PUCS employees is consistent with that of other LDC's. The plan is a contributory defined pension plan which is financed by equal contributions from the employer and employee based on the employee's contributory earnings. For the 2022 Test Year, PUC assumed OMERS rates of 9% on earnings up to CPP earning limits and 14.6% on earnings over CPP earnings limit as per OMER's website. The increases in OMERS premiums from 2018 through 2023 are explained by the increase in pension contribution rates.

Post Retirement Benefits

PUCS provides its retired employees with life insurance and medical benefits. The obligations for these post-employment benefit plans are actuarially determined by applying the projected unit credit method and reflect management's best estimate of certain underlying assumptions. Re-measurements of the net defined benefit obligations, including actuarial gains and losses and the return on plan assets (excluding interest), are recognized immediately in other comprehensive income. When the benefits of a plan are improved, the portion of the increased benefit relating to past service by employees is recognized immediately in profit or loss.

4.3.3 Shared Services and Corporate Cost Allocation

As a virtual utility, PUC shares certain resources with affiliates in order to create economies of scale and scope. Benefits are created both when a distributor purchases services from affiliates and when a distributor sells services to affiliates and receives revenue to offset its costs. Within the PUC group, the sharing of services is achieved through PUCS, which provides a range of services to PUC and other companies in the group, as well as to Public Utilities Commission (the "Commission"), a Municipal Services Board of the City. Wastewater services are also provided to the City of Sault Ste. Marie. As well, PUCS owns all of the shared assets of the group, including vehicles, tools and equipment, information technology and systems, etc. The arrangement is intended to create economies of scale and scope through the sharing of human and other resources. The costs incurred by PUCS are recovered through charges made by PUCS to the affiliates, including PUC.

PUCS provides both electricity billing to PUC and water/sewage billing to the Commission through a shared system. All of the activities of the PUC group of companies are carried out in a shared building at 500 Second Line East, which is owned by PUC. The portion of the building used by affiliates is made available by PUC under a lease arrangement. The lease is priced to affiliates at fully allocated cost. The Rent from Electric property is included in PUC's Other Revenue.

The following Tables 4-19 and 4-20 detail the corporate cost allocation for each year in the historic period as well as the test year. These tables are followed by a description of the allocation methodology and variance analysis.

Table 4-19: Shared Services and Corporate Cost Allocations

Appendix 2-N
Shared Services and Corporate Cost Allocation [1]

Year: 2018 Approved

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
PUC Distribution	PUC Services	Building Rental	Cost - no markup	$1,334,161	$1,334,161

Year: 2018 Actual

Shared Services

Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
From	To			$	$
PUC Distribution	PUC Services	Building Rental	Cost - no markup	$1,332,391	$1,332,391

Year: 2019 Actual

Shared Services

	Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
	From	To			$	$
1	PUC Distribution	PUC Services	Building Rental	Cost - no markup	$1,220,957	$1,220,957

Year: 2020 Actual

Shared Services

	Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
	From	To			$	$
2	PUC Distribution	PUC Services	Building Rental	Cost - no markup	$1,195,271	$1,195,271

Year: 2021 Actual

Shared Services

	Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
	From	To			$	$
3	PUC Distribution	PUC Services	Building Rental	Cost - no markup	$1,177,752	$1,177,752

Year: 2022 Bridge

Shared Services

	Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
	From	To			$	$
4	PUC Distribution	PUC Services	Building Rental	Cost - no markup	$1,070,245	$1,070,245

Year: 2023 Test

Shared Services

	Name of Company		Service Offered	Pricing Methodology	Price for the Service	Cost for the Service
	From	To			$	$
5	PUC Distribution	PUC Services	Building Rental	Cost - no markup	$1,035,470	$1,035,470

Shared Services - Variance Analyis

Service Offered	2018 Approved	2021 Actual	2023 Test	2023 Test vs 2021 Last Actual	2023 Test vs 2018 Board Approved
Building Rental	1,334,160.93	1,177,752.48	1,035,470.02	(142,282.46)	(298,690.91)

Table 4-20: Shared Services and Corporate Cost Allocation

Year: 2018 Approved

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$481,405
PUC Services	PUC Distribution	Collections Acct 5320 to 5335, excl. 5321	Cost - no markup	56.00%	$220,743
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$526,090
PUC Services	PUC Distribution	Admin Acct 5605 to 5665	Cost - no markup	41.31%	$1,819,004
PUC Services	PUC Distribution	Building 5675	Cost - no markup	46.45%	$416,453
					$3,463,696

Year: 2018 Actual

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$459,694
PUC Services	PUC Distribution	Collections Acct 5320 to 5335, excl. 5321	Cost - no markup	56.00%	$106,721
PUC Services	PUC Distribution	Collections Acct 5321	Cost - no markup	74.00%	$138,067
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$489,475
PUC Services	PUC Distribution	Admin Acct 5605 to 5665	Cost - no markup	41.31%	$1,713,924
PUC Services	PUC Distribution	Building 5675	Cost - no markup	46.45%	$337,731
					$3,245,611

Year: 2019 Actual

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$462,938
PUC Services	PUC Distribution	Collections Acct 5320 to 5335, excl. 5321	Cost - no markup	56.00%	$72,546
PUC Services	PUC Distribution	Collections Acct 5321	Cost - no markup	74.00%	$106,618
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$570,144
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665	Cost - no markup	41.31%	$1,773,625
PUC Services	PUC Distribution	Building 5675	Cost - no markup	46.45%	$351,249
					$3,337,120

1

Year: 2020 Actual

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$437,320
PUC Services	PUC Distribution	Collections Acct 5320 to 5335, excl. 5321	Cost - no markup	56.00%	$67,553
PUC Services	PUC Distribution	Collections Acct 5321	Cost - no markup	74.00%	$111,556
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$521,515
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665	Cost - no markup	41.31%	$1,836,617
PUC Services	PUC Distribution	Building 5675	Cost - no markup	46.45%	$319,987
					$3,294,548

2

Year: 2021 Actual

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$524,770
PUC Services	PUC Distribution	Collections Acct 5320 to 5335, excl. 5321	Cost - no markup	56.00%	$67,606
PUC Services	PUC Distribution	Collections Acct 5321	Cost - no markup	74.00%	$88,508
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$584,897
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665	Cost - no markup	41.31%	$2,614,914
PUC Services	PUC Distribution	Building 5675	Cost - no markup	46.45%	$333,356
					$4,214,051

3

Year: 2022 Bridge

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$419,153
PUC Services	PUC Distribution	Collections Acct 5320 to 5335, excl. 5321	Cost - no markup	56.00%	$73,077
PUC Services	PUC Distribution	Collections Acct 5321	Cost - no markup	74.00%	$63,362
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$634,233
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665	Cost - no markup	41.31%	$2,283,491
PUC Services	PUC Distribution	Building 5675	Cost - no markup	50.34%	$388,823
					$3,862,141

Year: 2023 Test

Corporate Cost Allocation

Name of Company		Service Offered	Pricing Methodology	% of Corporate Costs Allocated	Amount Allocated
From	To			%	$
PUC Services	PUC Distribution	Billing Acct 5305 to 5315	Cost - no markup	56.00%	$403,777
PUC Services	PUC Distribution	Collections Acct 5320 to 5335, excl. 5321	Cost - no markup	56.00%	$74,604
PUC Services	PUC Distribution	Collections Acct 5321	Cost - no markup	74.00%	$64,704
PUC Services	PUC Distribution	Customer Services Acct 5405 to 5420	Cost - no markup	56.00%	$662,219
PUC Services	PUC Distribution	Admin Acct 5605 to 5635, 5665	Cost - no markup	42.65%	$2,491,073
PUC Services	PUC Distribution	Building 5675	Cost - no markup	55.34%	$389,410
					$4,085,786

Corporate Cost Allocation - Variance Analysis

Service Offered	2018 Board Approved	2021 Actual	2023 Test	Test Year vs Last Actual	Test Year vs Board Approved
Billing Acct 5305 to 5315	$ 481,405	$ 524,770	$ 403,777	$ (120,994)	$ (77,628)
Collections Acct 5320 to 5335, excl. 5321	$ 133,432	$ 67,606	$ 74,604	$ 6,998	$ (58,829)
Collections Acct 5321	$ 87,311	$ 88,508	$ 64,704	$ (23,805)	$ (22,607)
Customer Services Acct 5405 to 5420	$ 526,090	$ 584,897	$ 662,219	$ 77,322	$ 136,129
Admin Acct 5605 to 5635, 5665	$ 1,819,004	$ 2,614,914	$ 2,491,073	$ (123,841)	$ 672,068
Building 5675	$ 416,453	$ 333,356	$ 389,410	$ 56,055	$ (27,043)
	$ 3,463,696	**$ 4,214,051**	**$ 4,085,786**	**$ (128,265)**	**$ 622,090**

Corporate Costs Allocation Methodology

PUCS provides electricity services, such as billing, collection, customer service, and administration services to the affiliated group, and water services to the Public Utilities

Commission. Administrative services include payroll, human resources, accounting, IT services, etc.

PUC engaged BDR North America Inc. ("BDR") to review PUC's method for allocating shared services in the fall of 2021. The review included consideration of the current method which was based on a review performed by RDI Consulting Inc. in 2007. PUC engaged BDR to review its methodology in the context of the current scope of shared services.

All pricing is at fully allocated cost. The methodology can be summarized as follows:

For business functions that include Operations, Customer Service, Collections, Vehicle operations, Regulatory and Stores, Warehouse and Procurement a direct assignment approach is identified. This approach provides an allocation of the dollar costs and an allocation of work time, or FTEs in each of these business functions. The allocated FTEs are then summed to provide a factor that is used to allocate the costs of resources and activities that support employees in their work. Supporting functions include Human Resources, Information and communications technology, office space, furniture and equipment, payroll administration, accounting, and finance. The number of users of each of the Supporting Functions is considered as reasonable, and in accordance with accepted principles of cost allocation, as an allocator of the costs of these functions. Any costs incurred in a supporting function that can be directly identified to a specific business unit are charged directly to that business unit.

The full report, *Full Absorption Cost Allocation Review* (December 17, 2021) is provided as Appendix B. Overall, the BDR review supported the methodology used in the past with updates to most current payroll data for time studies and direct charges.

The following Tables 4-21 and 4-22 details the allocation percentages to the affiliates for each of the shared services for 2021 and 2018. Overall, the updated factors have remained consistent with the prior report, a 3.42% increase compared to 2018 rates.

Table 4- 21: 2021 Shared Services Allocation

Shared Services	Allocator	PUC Distribution	Public Utilities Commision	PUC Services and Other Related Parties	Total
Billing	# customers	56.00%	44.00%	0.00%	100.00%
Collections	bad debt	74.00%	26.00%	0.00%	100.00%
Customer Services	# of customers	56.00%	44.00%	0.00%	100.00%
Administrative	Labour related effort	42.65%	48.68%	8.67%	100.00%
Building	% building utilized	55.34%	36.93%	7.73%	100.00%
Combined rate		**47.51%**	**42.57%**	**9.92%**	**100.00%**

Table 4-22: 2018 Shared Services Allocation

Shared Services	Allocator	PUC Distribution	Public Utilities Commision	PUC Services and Other Affiliates	Total
Billing	# customers	56.00%	44.00%	0.00%	100.00%
Collections	bad debt	74.00%	26.00%	0.00%	100.00%
Customer Services	# of customers	56.00%	44.00%	0.00%	100.00%
Administrative	Labour related effort	41.30%	43.80%	14.90%	100.00%
Building	% building utilized	46.45%	45.61%	7.94%	100.00%
Combined rate		**44.09%**	**42.57%**	**13.34%**	**100.00%**
Difference 2018 versus 2021		**3.42%**	**0.00%**	**-3.42%**	**0.00%**

4.3.4 Purchases of Non-Affiliate Services

PUC's purchasing policy establishes the principles, requirements, accountabilities and guidelines for the purchase of goods and services. The policy establishes amounts, requirements and approvals necessary to maintain full and open competition between supplies, vendors and contractors through the use of competitive bids, quotations and awards.

PUC confirms that it is in compliance with the Purchasing Policy. The policy ensures that all procurement activities within PUC maintain high legal, ethical, managerial, and professional standards. The policy identifies certain situations where a competitive bid process may not be followed. Exceptions are subject to approval by the President & CEO. A copy of PUC's Purchasing Policy is attached as Appendix C.

Table 4-23 below lists PUC's purchases that exceeded the materiality threshold in 2018 – 2022 of $135,000. The table also identifies the method of vendor selection. PUC anticipates using the same vendors for 2023, however new suppliers are continuously being sourced for best pricing. Occasionally, it is necessary to obtain services or products utilizing a single or sole source process. The details of the single/sole source process are included in the Purchasing Policy.

Table 4-23: Vendor Purchases

Vendor Name	Product/Service	Method of Selection	2018	2019	2020	2021	2022
17 TREES INC.	Line Clearing	Sole source			$ 435,492	$ 899,918	$ 370,372
ANIXTER POWER SOLUTIONS (HD)	TRX and Pole Line Hardware	Competitive Bid	$589,107	$ 488,666	$ 465,700	$ 520,076	$ 288,409
ASPLUNDH CANADA ULC	Line Clearing	Competitive Bid	$441,504	$ 578,870			
BELL CANADA -PRE.	Pole Attachments	Regulated		$ 136,326	$ 184,943	$ 188,643	$ 184,530
BORDEN LADNER GERVAIS LLP	Regulatory Services	Sole source	$206,202				
CAM TRAN CO LTD	Transformers, pole, line Hardware	Competitive Bid	$257,400	$ 415,609	$ 551,314	$ 394,309	$ 324,006
ECOBILITY INC.	AFT Program Delivery	Sole source	$261,940	$1,728,372	$1,298,090	$ 627,434	
EPTCON LTD.	Professional Engineering services	Competitive Bid			$ 183,514	$ 187,332	
GUILLEVIN INTERNATIONAL	PVC, Safety Items, Tools	Competitive Bid	$144,764	$ 144,629		$ 191,399	
JACO LINE CONTRACTORS LTD	Pole Testing	Competitive Bid			$ 287,524		
KTI LIMITED	Metering upgrades	Competitive Bid			$ 208,077		
NORAMCO WIRE & CABLE	Wire	Competitive Bid			$ 238,410		
ONTARIO ENERGY BOARD	OEB Fees	Regulated	$163,938	$ 148,402	$ 144,542		
OVERLAND CONTRACTING CANADA IN	SSG Project	Competitive Bid				$5,926,310	$1,547,634
PICKARD CONSTRUCTION	Customer Demand	Competitive Bid	$334,532	$ 289,056			
POWERNORTH UTILITY CONTRACTORS	Pole Pulling	Competitive Bid					$ 138,871
S & T ELECTRICAL	Customer Demand and Sub 16 Rebuild	Competitive Bid			$ 266,856	$3,095,318	$ 555,179
S S MARIE INNOVATION CENTRE	GIS Services	Sole Source	$336,488	$ 344,859	$ 324,409	$ 299,150	
SENSUS CANADA, INC	AMI Services	Competitive Bid			$ 167,335	$ 152,513	
SIEMENS CANADA LIMITED	Sub 16 Switchgear	Competitive Bid		$ 385,898	$ 736,528	$ 150,253	
SLING-CHOKER MFG LTD	Garage Doors	Competitive Bid				$ 446,662	
STELLA-JONES INC	Wood Poles	Competitive Bid	$334,113	$ 258,345	$ 208,999	$ 256,182	
SUPERIOR INDUSTRIAL	Upgrades at TS1 DUCT BANK	Competitive Bid	$195,426				
VIRGINIA TRANSFORMER CANADA	Sub 16 Transformers	Competitive Bid		$ 499,103	$ 441,684		
WSP CANADA INC.	Professional Engineering services	Competitive Bid	$217,872				

4.3.5 One-Time Costs

PUC has included one-time costs of $136,000 in its 2023 Test Year revenue requirement based on a five-year recovery until the next cost of service application. This amount represents one-fifth of the total forecasted costs of $680,000 related to this Application. The costs are identified in Table 4-23 below. PUC has not applied treatment of any other one-time costs in the Test Year OM&A.

4.3.6 Regulatory Costs

Reporting to the Finance Division, the Rates and Regulatory Affairs Officer is responsible for preparing regulatory filings and rate applications, performing settlement reviews and reconciliations, ensuring regulatory and legislative compliance, performing business and process reviews, participating in regulatory consultations and providing reporting and timely responses to regulatory bodies. Due to the complexity and workload involved in completing regulatory tasks, other members of the Management team are required on an on-going basis to ensure regulatory and legislative compliance and also to provide assistance in preparing rate applications. PUC has included an estimate of total staff costs related to on-going costs in Table 4-24 below.

Other regulatory expenses include annual assessment fees paid to the OEB, cost awards for hearings, proceedings and other matters before the regulatory body and costs associated with consultants providing regulatory compliance assistance. The 2023 Test Year includes an estimate of the full cost of OEB assessments.

Annual ongoing costs include the OEB assessment, section 30 costs, miscellaneous regulatory and training costs, and staff resources allocated to regulatory matters. PUC will incur significant costs for preparing, processing and seeking approval of this application. The costs include consulting and legal fees, incremental expenses related to staff resources, and intervenor costs awards as identified in the Table 4-24 below. As noted above in the variance analysis section, the total application costs are forecasted to be $680,000. Costs are over the 5-year rate period and have been included in Test Year expenses. Total costs have been included in expenses in the 2023 Test Year.

Table 4-24 Regulatory Cost Schedule

	Regulatory Cost Category	USoA Account	Last Rebasing Year (2018 OEB Approved)	Last Rebasing Year (2018 Actual)	Most Current Actuals Year 2021	2022 Bridge Year	Annual % Change	2023 Test Year	Annual % Change
	(A)	(B)	(D)	(E)	(F)	(G)	(H)=[(G)-(F)]/(F)	(I)	(J) = [(I)-(G)]/(G)
	Regulatory Costs (Ongoing)								
1	OEB Annual Assessment	5655	180,000	142,277	137,339	140,000	1.94%	143,000	2.14%
2	OEB Section 30 Costs (OEB-initiated)	5655	10,000	3,247	6,919	10,000	44.53%	10,000	0.00%
3	Expert Witness costs for regulatory matters								
4	Legal costs for regulatory matters								
5	Consultants' costs for regulatory matters	5655	106,816		16,893	20,000	18.40%	20,000	0.00%
6	Operating expenses associated with staff resources allocated to regulatory matters	5655	95,341	79,739	113,204	179,944	58.96%	302,858	68.31%
7	Operating expenses associated with other resources allocated to regulatory matters								
8	Other regulatory agency fees or assessments								
9	Any other costs for regulatory matters (please define)								
10	Intervenor costs	5655							
11	Include other items in green cells, as applicable								
	Regulatory Costs (One-Time)								
1	Expert Witness costs								
2	Legal costs								
3	Consultants' costs	5655	515,000	266,633				430,634	
4	Incremental operating expenses associated with staff resources allocated to this application.			210,958				126,366	
5	Incremental operating expenses associated with other resources allocated to this application.								
6	Intervenor costs		74,000	63,670				100,000	
7	OEB Section 30 Costs (application-related)			18,191				20,000	
8	Settlement Conference Expenses	5655	10,000	19,336				3,000	
1	Sub-total - Ongoing Costs		$ 392,157	$ 225,263	$ 274,354	$ 349,944	27.55%	$ 475,858	35.98%
2	Sub-total - One-time Costs		$ 599,000	$ 578,788	$ -	$ -		$ 680,000	
3	Total		$ 511,957	$ 804,051	$ 274,354	$ 349,944	27.55%	$ 611,858	74.84%

Application-Related One-Time Costs	Total	Total
Total One-Time Costs Related to Application to be Amortized over IRM Period	$ 599,000	$ 680,000
1/5 of Total One-Time Costs	$ 119,800	$ 136,000

One-time costs include consulting costs for legal and consulting assistance from experienced subject matter experts. These are identified in Table 4-25.

Table 4- 25: One Time Cost of Service Application Costs

Cost of Service Application Costs	Total COS
Incremental operating expenses associated with staff resources allocated to this application.	$ 126,366
Consultants' costs (legal, DSP, Shared Services, LRAM)	$ 430,634
Intervenor costs (4)	$ 100,000
OEB application costs	$ 20,000
Settlement conference costs (virtual)	$ 3,000
	$ 680,000

4.3.7 Low-Income Energy Assistance Programs ("LEAP")

In March 2009, the OEB issued its Report of the Board: Low Income Energy Assistance Program (the "LEAP Report") which describes policies and measures for electricity distributors to assist low-income energy consumers, including emergency financial assistance.

The delivery of LEAP relies heavily on the cooperation between PUC and its lead social agency, United Way – Community Assistance Trust, to administer the program within PUC's service territory.

In accordance with filing guidelines 2.4.3.6, PUC understands that the LEAP financial assistance is an ongoing cost, therefore, PUC has included an estimated amount of $31,144 in its 2023 test year expenses. PUC understands that the included figure is a placeholder for LEAP. At the time the final rates are determined, PUC will update this figure as calculated in Table 4-26. In the table below, this amount is based on 0.12% of the 2023 test year revenue requirement. This amount has been included in Account 6205 – Donations, to ensure that it is captured appropriately in the revenue requirement.

PUC's 2023 Test Year revenue requirement does not include any legacy low-income energy assistance programs.

Table 4-26: LEAP

2023 Test Year	
Service Revenue Requirement	$27,952,199
LEAP %	0.12%
LEAP $	$33,543
LEAP Amount Used $	$31,144

4.3.8 Charitable and Political Donations

Other than the LEAP charitable donations, PUC has not included any other charitable donations in OM&A expenses.

PUC also confirms it does not make political contributions; therefore, no political contributions have been included for recovery.

4.3.9 Non-Recoverable and Disallowed Expenses

PUC does not have any expenses that are deducted for general tax purposes but for which recovery in 2023 distribution rates would be disallowed.

4.4 CONSERVATION AND DEMAND MANAGEMENT (“CDM”)

4.4.2 Lost Revenue Adjustment Mechanism ("LRAM") for 2018-2022

PUC proposes to recover an LRAMVA (Account 1568) amount of $201,460 for CDM activities completed in 2018 and 2019 and persistence of CDM activities from 2017, 2018 and 2019 through 2022. This amount includes carrying charges to December 31, 2022 of $6,941. PUC's last LRAMVA claim was approved as part of its 2019 IRM proceeding for savings through to 2017.

PUC is not currently running any CDM programs and confirms that no CDM costs are included in its Test Year revenue requirement. PUC did not offer any programs under the Interim Framework.

Background

On March 31, 2011, the Minister of Energy and Infrastructure issued a directive (the "Directive") to the OEB regarding electricity CDM targets to be met by licensed electricity distributors. On April 26, 2012, the OEB issued *Guidelines for Electricity Distributor Conservation and Demand Management* (EB-2012-0003 – the "CDM Guidelines"). In keeping with the Directive, the OEB adopted a mechanism to ensure LDCs were kept whole for encouraging customer CDM.

The OEB authorized the establishment of LRAMVA Account 1568 (LRAMVA) to capture, at the customer class level, the difference between:

- The results of actual, verified impacts of authorized CDM activities undertaken by distributors for both OEB-Approved CDM programs and IESO-Contracted Province-Wide CDM programs in relation to activities undertaken by the distributor and/or delivered for the distributor by a third party under contract (in the distributor's franchise area); and
- The level of CDM program activities included in the distributor's load forecast (i.e., the level embedded in rates).

On March 26, 2014, the Minister of Energy issued a directive regarding the new Conservation First Framework ("CFF") for conservation and demand management activities in place from 2015 to 2020 and continuance of the lost revenue adjustment mechanism.

On March 20, 2019, the Minister of Energy, Northern Development and Mines ("MENDM") issued a directive to the IESO mandating the discontinuance of the CFF and the establishment of an Interim Framework for CDM programming. Under the Interim Framework, the new province-wide target for CDM savings was 1.4 TWh and the framework was scheduled to expire on December 31, 2020.

Subsequent to the discontinuance of the 2015-2020 CFF, on June 20, 2019, the OEB issued a letter[5] to distributors stating that distributors should continue to have access to LRAM related to the successful delivery of CFF programs. In addition, the OEB updated the Chapter 2 filing requirements to make modifications reflecting the new requirements set forth in the interim framework.

On July 22, 2020, the MENDM issued a directive to the IESO mandating the extension of timelines for certain projects and related deadlines under the CFF to June 30, 2021. These extensions are intended to offset the disruptions caused by COVID-19 for participants and those businesses involved in delivering CDM programs. Contracted program participants in the certain CFF programs are eligible for project extensions to June 30, 2021 (i.e., Retrofit Program, Process and Systems Upgrade Program, Residential New Construction Program, High Performance New Construction Program). On December 9, 2021, the deadline was extended once more to December 31, 2022.

LRAM Variance Account (LRAMVA)

PUC is applying for disposition of Account 1568 – LRAMVA to recover lost revenues in the amount of $201,460. PUC is requesting disposition of the net lost revenues from:

- Persistence of 2017 results from January 1, 2018 to December 31, 2022;

[5] OEB Letter, June 20, 2019, Lost Revenue Adjustment Mechanism for 2020 Rate Applications

- Results of programs offered in 2018, and persistence of 2018 results through to December 31, 2022; and
- Results of programs offered in 2019, and persistence of 2019 results through to December 31, 2022.

PUC did not have any CDM projects or programs completed in 2020 or 2021.

Some of the projects in these programs were not finalized until after the programs shut down, but all were approved before April 1, 2019 as part of the CFF. PUC confirms its claim for 2018 through 2022 is considered final.

A summary of the LRAMVA disposition request by customer class including projected carrying charges to December 31, 2022, is presented in Table 4-27.

Table 4-27: LRAM

Customer Class	Billing Unit	Principal ($)	Carrying Charges ($)	Total LRAMVA ($)
Residential	kWh	$42,005	$2,502	$44,507
GS<50 kW	kWh	($103,740)	($3,211)	($106,950)
GS 50-4,999 kW	kW	$256,254	$7,650	$263,903
Unmetered Scattered Load	kWh	$0	$0	$0
Sentinel Lighting	kW	$0	$0	$0
Street Lighting	kW	$0	$0	$0
Total		**$194,519**	**$6,941**	**$201,460**

Methodology for Calculating LRAMVA

PUC retained IndEco Strategic Consulting Inc. ("IndEco") to develop its 2023 LRAMVA claim. Their full report is available in Appendix D. PUC has also submitted the completed OEB LRAMVA work form as a live excel file, "PUC_2023_LRAMVA_Workform_20220831". IndEco used the most recent input assumptions available at the time of the program evaluation, including the following information:

- IESO's 2017 final verified CDM results report for PUC Distribution Inc. (filed with EB-2018-0219);
- IESO's 2017 final verified CDM results report by project for PUC Distribution Inc. (key results on Tab 3-a of the live workform);
- IESO's April 2019 Participation and Cost Report ("P&C") for PUC Distribution Inc. (filed live excel file, "PUC_2023_Participation and Cost Report (2019 04) _20220831"); and
- PUC's CDM databases for project data in 2018 and 2019 (key results on Tab 3-a of the workform).

For 2017, the 2017 final verified results report contains net energy and demand savings by program, and persistence of these beyond the forecast period. The results by project were used to determine the allocation of savings for the Audit Funding and Retrofit Programs, which spanned more than one customer class. The customer class for each project was determined, and the percentage of energy savings (for projects in GS<50 kW) and demand savings (for projects in GS 50-4,999 kW) were calculated. Information about projects, and the calculation of the allocation is provided on a new Tab 3-a of the LRAMVA work form. Some additional 2017 savings were identified in the April 2019 P&C. Net demand and persistence of these were calculated based on net demand and persistence of the other results for that program in the final verified 2017 values.

For 2018 and 2019, residential net energy savings in 2018 and 2019, and their persistence in 2020 were taken from the April 2019 Participation and Cost ("P&C") report for PUC. Net energy savings for 2018 and 2019 in the program year and 2020 were also taken from that report. Persistence of these is based on the persistence of that program seen in the verified 2017 results.

The P&C report did not fully capture all projects completed in 2018 and 2019, nor does it identify the individual projects included. PUC databases were used to identify the gross reported energy and demand savings for non-residential projects. These were then multiplied by the 2017 verified net-to-gross and realization rate values for that program to determine net savings. Persistence was estimated using the same rate of persistence loss seen in the 2017 final verified results. Allocation across customer classes was calculated as for the 2017 results.

Savings already captured in the 2018 load forecast were subtracted from the savings calculated to get the variance in load that results in lost revenues. The amount in the load forecast is the LRAMVA threshold specified in the Settlement Agreement of EB-2017-0071 and reproduced in the Board's decision.
The uncaptured savings are multiplied by the appropriate annualized volumetric distribution rate for each class to determine the lost revenues in that class.

Carrying charges on outstanding amounts from January 1, 2018 through December 31, 2022 are calculated according to the OEB specified methodology and using OEB interest rates. OEB has not yet prescribed the interest rate for Q4 2022. The most recent rate (for Q3 2022) was assumed to persist.

<u>Rate Rider Calculation</u>

PUC proposes to recover the LRAMVA amount of $201,460 through class-specific volumetric rate riders that would be in effect for a period of 12 months from May 1, 2023 to April 30, 2024. These class-specific rate riders were determined by totalling the class-specific LRAMVA amounts by program and dividing by volumetric billing determinants consistent with the proposed load forecast. The proposed rate riders are shown in Table 4-28 below.

Table 4-28: LRAM Rate Rider

Rate Class	Units	kW / kWh / # of Customers	Allocated Account 1568	Rate Rider for Account 1568
Residential	kWh	274,738,681	$ 44,507	**0.0002**
GS<50 kW	kWh	79,051,528	$ (111,834)	**(0.0014)**
GS 50-4,999 kW	kW	547,687	$ 263,903	**0.4819**
Unmetered Scattered Load	kWh	878,528		**-**
Sentinel Lighting	kW	7,200		**-**
Street Lighting	kW	566		**-**
Total			**$ 196,576**	

There are no savings claimed, and there is thus no rate rider for Unmetered Scattered Load, Sentinel Lighting, or Streetlighting as there were no projects in any of these customer classes over the period being claimed. It is appropriate to make a claim for other customer classes at this time, as no additional projects are expected to be finalized as part of the Conservation First Framework.

APPENDIX A PUCS

Actuary Valuation

Report 2021

PUC SERVICES INC.

REPORT ON THE ACTUARIAL VALUATION OF POST-RETIREMENT NON-PENSION BENEFITS

AS AT DECEMBER 31, 2021

FINAL – February 11, 2022

THE POWER OF BEING UNDERSTOOD
AUDIT | TAX | CONSULTING

RSM

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Purpose

RSM Canada Consulting LP was engaged by PUC Services Inc. (the "Corporation") to perform an actuarial valuation of the post-retirement non-pension benefits sponsored by the Corporation and to determine the accounting results for those benefits for the fiscal period ending December 31, 2021. The nature of these benefits is defined benefit.

This report is prepared in accordance with the International Financial Reporting Standards ("IFRS") guidelines for post-retirement non-pension benefits as outlined in the International Accounting Standard 19 – Employee Benefits ("IAS 19").

The most recent full valuation was prepared as at December 31, 2018 based on the assumptions chosen by management at that date and in accordance with IAS 19.

The purpose of this valuation is threefold:

i) To determine the Corporation's liabilities in respect of post-retirement non-pension benefits at December 31, 2021;

ii) To determine the defined benefit costs to be recognized for fiscal year 2021; and

iii) To provide all other pertinent information necessary for compliance with IAS 19.

Note that all monetary figures in this report are rounded to the nearest hundreds of dollars and summated figures in this report may not match total figures due to rounding.

The intended users of this report include the Corporation and its auditors. This report is not intended for use by the plan beneficiaries or for use in determining any funding of the benefit obligations.

Included in the Appendix attached hereto are detailed accounting schedules containing the results of the valuation.

SECTION A — VALUATION RESULTS

Section A.1 shows the key valuation results compared to previous year's figures projected from the most recent full valuation as well as a breakdown between active and retired individuals and type of benefit.

Section A.2 shows the sensitivity of the valuation results to certain changes in assumptions. We have shown an increase/decrease in the health claims cost trend rates by 1% per annum and an increase/decrease in the discount rate by 1% per annum.

Section A.3 shows the development of changes in the present value of defined benefit obligation as a result of the re-measurement at December 31, 2021.

RSM

Valuation Results

Section A.1—Valuation Results

Results from the actuarial valuation as at December 31, 2021 compared to previous year's figures projected from the most recent full valuation:

	December 31, 2020	December 31, 2021
Present Value of Defined Benefit Obligation (PV DBO)	**2,349,500**	**1,786,800**

	CY 2020	CY 2021
Current Service Cost	146,800	137,300
Interest Cost	63,800	59,900
Defined Benefit Cost Recognized in Income Statement	210,500	**197,200**
Actuarial (Gain)/Loss	120,100	(669,400)
Defined Benefit Cost Recognized In OCI	**120,100**	**(669,400)**
Defined Benefit Cost	**330,600**	**(472,200)**

The following table provides results from the actuarial valuation as at December 31, 2021 broken down by active (including LTD) and retired individuals and type of post-retirement non-pension benefit:

Dec. 31, 2021 PV DBO	Actives (incl. LTD)	Retirees	Total
Life	30,100	106,500	**136,600**
Health	1,209,400	440,800	**1,650,200**
Total	**1,239,500**	**547,300**	**1,786,800**

Sensitivity Analysis

Section A.2—Sensitivity Analysis

	Dec. 31, 2021 PV DBO	Difference	% Difference
Base Assumptions	1,786,800		
Cost Trends +1%	1,983,100	196,300	11%
Cost Trends -1%	1,619,900	(166,900)	-9%
Discount Rate +1%	1,590,800	(195,900)	-11%
Discount Rate -1%	2,025,700	238,900	13%

Management's best estimate assumptions are those outlined in *Section C – Summary of Actuarial Method and Assumptions* in this report.

Development of Changes in the Present Value of Defined Benefit Obligation

Section A.3—Development of Changes in the Present Value of Defined Benefit Obligation

PV DBO at December 31, 2020	2,349,500
2021 Current Service Cost	137,300
2021 Benefit Payments	(90,500)
2021 Interest Cost	59,900
Expected PV DBO at December 31, 2021	**2,456,200**
Actuarial (Gain)/Loss at December 31, 2021	(669,400)
PV DBO at December 31, 2021	**1,786,800**

The decrease indicated above of $669,400 in the PV DBO from the expected PV DBO at December 31, 2021 is due to the re-measurement of the liability; a breakdown of the changes is as follows:

Change in composition of active and retiree data (actual experience different from expected)	(98,700)
Change in assumptions:	
Claims Cost	(390,700)
Withdrawal Table	(113,300)
Discount Rate	(66,700)
Total Actuarial (Gain)/Loss at December 31, 2021	**(669,400)**

Pursuant to IAS 19, the re-measurement of the PV DBO at December 31, 2021 based on the changes in the assumptions and experience is recognized immediately in other comprehensive income at December 31, 2021.

SECTION B — PLAN PARTICIPANTS

Section B.1 sets out the summary information with respect to the plan participants valued in the current valuation compared to those valued in the previous valuation.

Section B.2 reconciles the number of participants in the previous valuation to the number of participants in the current valuation.

Participation Data

Section B.1—Participant Data

Membership data as at October 31, 2021 was received from the Corporation via e-mail and included information such as name, sex, age, date of hire, benefit amounts and other applicable details for all active employees and people in receipt of benefits.

Although the data provided reflected status and benefit information as at October 31, the Corporation has indicated that any changes in status and other member data occurring from October 31 to December 31 are not expected to be material to the valuation results.

We have reviewed the data and compared it to the data used in the previous valuation for consistency and reliability for use in this valuation. The main tests of sufficiency and reliability that were conducted on the membership data are as follows:

- Date of hire prior to date of birth;
- Ages under 18 or over 100;
- Abnormal levels of benefits and/or premiums; and
- Duplicate records

In addition, the following tests were performed:

- A reconciliation of statuses from the prior valuation to the current valuation;
- A review of the consistency of individual data items and statistical summaries between the current and prior valuations; and
- A review of the reasonableness of changes in such information since the prior valuation.

	November 30, 2018	October 31, 2021
Employee Count		
Male	123	122
Female	50	47
Total	**173**	**169**
Employee Average Service		
Male	12.0	10.5
Female	10.9	9.5
Total	**11.7**	**10.2**
Retiree (in Receipt of Benefits) Count		
Male	64	67
Female	23	24
Total	**87**	**91**

	Employee Count as of October 31, 2021			Employee Avg Service as of October 31, 2021		
Age	**Male**	**Female**	**Total**	**Male**	**Female**	**Total**
< 30	8	1	9	3	2	3
30 - 35	12	11	23	5	5	5
36 - 40	26	5	31	10	10	10
41 - 45	26	7	33	9	11	9
46 - 50	18	13	31	13	10	12
51 - 55	19	7	26	13	14	13
56 - 60	8	3	11	12	9	11
61 - 65	4	-	4	23	-	23
66 - 70	1	-	1	33	-	33
71 - 75	-	-	-	-	-	-
> 75	-	-	-	-	-	-
Total	**122**	**47**	**169**	**10.5**	**9.5**	**10.2**

Participant Reconciliation

Section B.2—Participation Reconciliation

	Actives	Disabled	Retired
November 30, 2018	**173**	**3**	**87**
New Entrants	37	-	-
Actives	-	3	33
Terminated	(11)	-	-
Retired	(33)	-	-
Deceased	-	-	(11)
Disabled	(3)	-	-
Not Eligible for Benefits*	-	-	(18)
October 31, 2021	**163**	**6**	**91**

** These 18 individuals are no longer eligible for benefits as they are over the eligibility age (age 65) for post-retirement health benefits and have also opted out of post-retirement life benefits.*

SECTION C — SUMMARY OF ACTUARIAL METHOD AND ASSUMPTIONS

Actuarial Method

The aim of an actuarial valuation of post-retirement non-pension benefits is to provide a reasonable and systematic allocation of the cost of these future benefits to the years in which the related employees' services are rendered. To accomplish this, it is necessary to:

- make assumptions for discount rates, mortality, and other decrements;
- use these assumptions to calculate the present value of the expected future benefits; and,
- adopt an actuarial cost method to allocate the present value of expected future benefits to the specific years of employment.

The Defined Benefit Obligation and Current Service Cost were determined using the projected benefit method, pro-rated on service. This is the method stipulated by IAS 19. Under this method, the projected post-retirement benefits are deemed to be earned on a pro-rata basis over the years of service in the attribution period. IAS 19 stipulates that the attribution period commences on the date when service by the employee first leads to benefits under the plan (whether or not the benefits are conditional on further service) and ends on the date when further service by the employee will lead to no material amount of further post-retirement non-pension benefits under the plan, other than from further salary increases.

For each employee not yet fully eligible for benefits, the Present Value of the Defined Benefit Obligation (PV DBO) is equal to the present value of expected future benefits multiplied by the ratio of the years of service to the valuation date to the total years of service in the attribution period. The Current Service Cost is equal to the present value of expected future benefits multiplied by the ratio of the year (or part) of service in the fiscal year to total years of service in the attribution period.

The PV DBO at December 31, 2021 is based on membership data as at October 31, 2021 and management's best estimate assumptions established for calculations as at December 31, 2021.

For health benefits, the Corporation has selected the premium rates charged retirees as management's best estimate of the benefits costs to be incurred. The total monthly premium rates, inclusive of premium taxes, used for the current and previous valuation are as follows:

	Current Valuation (Plan E)		Current Valuation (Plan E1)	
Effective Period	Health Single	Health Family	Health Single	Health Family
April 1, 2021 – December 31, 2021	$ 76.20	$ 194.69	$ 91.77	$ 214.21

	Previous Valuation	
Effective Period	Health Single	Health Family
March 1, 2019 – February 28, 2020	$ 90.04	$ 228.00

The rates above are at the 100% level and prior to any cost-sharing provisions under the plan.

Management's Best Estimate Assumptions

The following are management's best estimate economic and demographic assumptions for calculations as at December 31, 2021.

Economic Assumptions

Discount Rate

The rate used to discount future benefits is assumed to be 2.90% per annum as of December 31, 2021. This rate reflects the Corporation's expected projected benefit cash flows for post-retirement non-pension benefits and the market yields on high quality bonds at the time of preparing the valuation.

The assumption used in the previous valuation was 4.00% per annum as at December 31, 2018, which was subsequently updated to 2.60% as at December 31, 2020.

Claims Cost Trend Rate

The rates used to project benefits costs into the future were chosen based on a research paper published by the Canadian Institute of Actuaries – *Model of Long-Term Health Care Cost Trends in Canada* - dated March 2018. This assumption remains unchanged from the previous valuation.

The following table provides a sample of the health trend rates used in the current valuation.

	Current Valuation
Year	Health
2022	4.70%
2025	5.30%
2030	5.30%
2035	4.60%
2040 and thereafter	4.00%

Demographic Assumptions

Mortality Table

The mortality tables used are as per the Canadian Institute of Actuaries Canadian Pensioners' Mortality Pension Experience Subcommittee final report dated February 11, 2014 (CIA Report). More specifically, the Canada Pensioners Mortality ("CPM") Table Public Sector (CPM2014 PUBL) has been used with the generational projection of mortality improvement based upon the CIA MI-2017 mortality improvement scale published in 2017.

This assumption remains unchanged from the previous valuation.

Rates of Withdrawal

Termination of employment is assumed to be in accordance with the following withdrawal table:

Age Bucket	Current Valuation
18 – 29	2.90%
30 – 34	2.15%
35 – 39	1.85%
40 – 49	1.45%
50 – 54	1.25%

In the previous valuation, termination of employment is assumed to be 0.5% per annum prior to age 55.

Retirement Age

All active employees are assumed to retire at age 59 (or immediately if currently over age 59), which was based on the Corporation's retirement experience as well as a seven year retirement experience study on a group of local distribution companies for which data was available.

This assumption remains unchanged from the previous valuation.

Disability

No provision was made for future disability

This assumption remains unchanged from the previous valuation.

Other Assumptions

Family/Single Coverage

The following assumptions were chosen for the current valuation and are unchanged from the previous valuation:

- Coverage Type at Retirement (i.e. family, single) – The employee's coverage type at the valuation date will remain the same until the employee reaches the assumed retirement age.
- Spousal Gender – For employees with family coverage, the retiree has a spouse of the opposite gender at the date of retirement.
- Spousal Age Offset – Male spouses are assumed to be three years older than female spouses.

Coverage Participation

Upon retirement, it is assumed that 50% of eligible retirees will opt to continue with the life insurance benefit and 100% of eligible retirees will opt to receive extended health benefits until age 65.

This assumption remains unchanged from the previous valuation.

Expenses and Taxes

The taxes and expenses are included in the premium rates assumed for health benefits.

We have assumed 10% of benefits is required for the cost of sponsoring the program for post-retirement life insurance.

These assumptions remain unchanged from the previous valuation.

SECTION D — SUMMARY OF POST-RETIREMENT BENEFITS

The following is a summary of the plan provisions that are pertinent to this valuation, based on information provided by and discussions with the Corporation.

Eligibility

All employees who retire from the Corporation have the option to sign up for post-retirement life insurance benefits and extended health coverage.

Participant Contributions

The Corporation shall pay 50% of the cost of life insurance benefits for all retirees if they choose to sign up for life insurance, except for the retirees with coverage amount of $2,000, of which 100% of the cost will be paid.

The Corporation shall pay 100% of the cost of the extended health care until 65 for all retirees if they choose to keep the benefit.

Past Service

Past service is defined as continuous service prior to joining the plan if the participant was employed by another electrical distribution company prior to joining the Corporation.

Length of Service

Length of service is defined as continuous service from the date of hire to the valuation date, measured in years and months.

RSM

Summary of Benefits

Life Insurance

All eligible early retirees who choose to sign up for post-retirement life insurance are entitled to lifetime post-retirement life insurance with a flat benefit coverage amount of $5,000, the cost of which is shared equally between the Corporation and the retiree. There are exceptions for a few retirees who have flat benefit coverage amounts of $2,000 which is fully paid by the Corporation.

Health Benefits

All eligible employees are entitled to receive post-retirement health benefits to age 65.

A detailed description of the health benefits covered under the post-retirement non-pension benefits plan can be found in benefit information booklets provided to employees.

ACTUARIAL CERTIFICATION

An actuarial valuation has been performed on the post-retirement non-pension benefit plans sponsored by PUC Services Inc. (the "Corporation") as at December 31, 2021, for the purposes described in this report.

In accordance with the Canadian Institute of Actuaries Consolidated Standards of Practice General Standards, we hereby certify that, in our opinion, for the purposes stated in the Executive Summary:

1. The data on which the valuation is based is sufficient and reliable;
2. The assumptions employed, as outlined in this report, have been selected by the Corporation as management's best estimate assumptions (no provision for adverse deviations) and we express no opinion on them;
3. All known legal and constructive obligations with respect to the post-retirement non-pension benefits sponsored by and identified by the Corporation are included in the calculations; and
4. This report has been prepared, and our opinions given, in accordance with accepted actuarial practice in Canada.

We are not aware of any subsequent events after the date of completing this valuation that would have a significant effect on the valuation results contained herein.

The latest date on which the next actuarial valuation should be performed is December 31, 2024. If any supplemental advice or explanation is required, please advise the undersigned.

Respectfully submitted,
RSM CANADA CONSULTING LP

Stanley Caravaggio

Stanley Caravaggio, FSA, FCIA
Director

Jamie Wong

Jamie Wong, ASA, ACIA
Manager

Toronto, Ontario

February 11, 2022

SECTION E — EMPLOYER CERTIFICATION

Post-Retirement Non-Pension Benefit Plan
of PUC Services Inc.
Actuarial Valuation as at December 31, 2021

I hereby confirm, as an authorized signing officer of the administrator of the Post-Retirement Non-Pension Benefit Plan of PUC Services Inc. that, to the best of my knowledge and belief, for the purposes of the valuation:

i) The membership data summarized in Section B is accurate and complete;

ii) The assumptions upon which this report is based as summarized in Section C, are management's best estimate assumptions and are adequate and appropriate for the purposes of this valuation; and

iii) The summary of Plan Provisions in Section D is an accurate and complete summary of the terms of the Plan in effect on December 31, 2021.

PUC SERVICES INC.

February 9, 2022	Kim McLellan
Date	Signature
Kelly McLellan	VP, Finance and Corporate Support
Name	Title

APPENDIX — DETAILED ACCOUNTING SCHEDULES

RSM

PUC Services Inc.

Estimated Benefit Expense (IAS 19)

FINAL

	Actuals CY 2021 *	Projected ** CY 2022	Projected ** CY 2023	Projected ** CY 2024
Discount Rate at January 1	2.60%	2.90%	2.90%	2.90%
Discount Rate at December 31	2.90%	2.90%	2.90%	2.90%
Health Benefit Cost Trend Rate at December 31	4.40%	4.70%	4.90%	5.10%
Dental Benefit Cost Trend Rate at December 31	4.70%	4.90%	5.10%	5.40%
Long Term Health and Dental Benefit Cost Trend Rate	4.00%	4.00%	4.00%	4.00%
First Year Of Long Term Health and Dental Benefit Cost Trend Rate	2040	2040	2040	2040
Assumed Increase in Employer Contributions	actual	expected ***	expected ***	expected ***
A. Change in the Net Defined Benefit Liability/(Asset) Recognized in Balance Sheet				
Net Defined Benefit Liability/(Asset) as at January 1	2,349,497	1,786,769	1,854,163	1,919,184
Defined Benefit Cost Recognized in Income Statement	197,195	180,674	183,005	186,793
Defined Benefit Cost Recognized in Other Comprehensive Income	(669,408)	-	-	-
Benefits Paid by the Employer	(90,515)	(113,280)	(117,984)	(119,337)
Net Defined Benefit Liability/(Asset) as at December 31	1,786,769	1,854,163	1,919,184	1,986,640
B. Determination of Defined Benefit Cost				
B1. Determination of Defined Benefit Cost Recognized in Income Statement				
Current Service Cost	137,285	130,489	130,933	132,854
Interest Cost	59,910	50,185	52,072	53,939
Defined Benefit Cost Recognized in Income Statement	197,195	180,674	183,005	186,793
B2. Remeasurements of the Net Defined Benefit Liability/(Asset) Recognized in Other Comprehensive Income				
Net Actuarial Loss/(Gain) arising from Changes in Financial Assumptions	(457,388)	-	-	-
Net Actuarial Loss/(Gain) arising from Changes in Demographic Assumptions	(113,293)	-	-	-
Net Actuarial Loss/(Gain) arising from Experience Adjustments	(98,727)	-	-	-
Return on Plan Assets (Excluding Amounts Included in Net Interest Cost)	-	-	-	-
Change in Effect of Asset Ceiling	-	-	-	-
Defined Benefit Cost Recognized in Other Comprehensive Income	(669,408)	-	-	-
Total Defined Benefit Cost	(472,213)	180,674	183,005	186,793
C. Change in the Present Value of Defined Benefit Obligation				
Present Value of Defined Benefit Obligation as at January 1	2,349,497	1,786,769	1,854,163	1,919,184
Current Service Cost	137,285	130,489	130,933	132,854
Interest Cost	59,910	50,185	52,072	53,939
Benefits Paid	(90,515)	(113,280)	(117,984)	(119,337)
Net Actuarial Loss/(Gain)	(669,408)	-	-	-
Present Value of Defined Benefit Obligation as at December 31	1,786,769	1,854,163	1,919,184	1,986,640

* The expected December 31, 2021 PV DBO and CY 2021 defined benefit cost are calculated based on membership data at December 31, 2018 and management's best estimate assumptions at December 31, 2020.

** Projected CY 2022, 2023, and 2024 results are provided for informational purposes only. Significant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require revised projections or a full actuarial review.

*** Based on exepcted benefits to be paid to those eligible for benefits.

02/11/2022

RSM

PUC Services Inc.
Estimated Benefit Expense (IAS 19)
FINAL

	Actuals CY 2021 *	Projected ** CY 2022	Projected ** CY 2023	Projected ** CY 2024
Discount Rate at January 1	2.60%	2.90%	2.90%	2.90%
Discount Rate at December 31	2.90%	2.90%	2.90%	2.90%
Health Benefit Cost Trend Rate at December 31	4.40%	4.70%	4.90%	5.10%
Dental Benefit Cost Trend Rate at December 31	4.70%	4.90%	5.10%	5.40%
Long Term Health and Dental Benefit Cost Trend Rate	4.00%	4.00%	4.00%	4.00%
First Year Of Long Term Health and Dental Benefit Cost Trend Rate	2040	2040	2040	2040
Assumed Increase in Employer Contributions	actual	expected ***	expected ***	expected ***

D. Calculation of Component Items

Interest Cost				
Present Value of Defined Benefit Obligation as at January 1	2,349,497	1,786,769	1,854,163	1,919,184
Benefits Paid	(45,258)	(56,640)	(58,992)	(59,669)
Accrued Benefits	2,304,240	1,730,129	1,795,171	1,859,516
Interest Cost	59,910	50,185	52,072	53,939
Expected Present Value of Defined Benefit Obligation as at December 31				
Present Value of Defined Benefit Obligation as at January 1	2,349,497	1,786,769	1,854,163	1,919,184
Current Service Cost	137,285	130,489	130,933	132,854
Benefits Paid	(90,515)	(113,280)	(117,984)	(119,337)
Interest Cost	59,910	50,185	52,072	53,939
Expected Present Value of Defined Benefit Obligation as at December 31	2,456,177	1,854,163	1,919,184	1,986,640

E. Net Actuarial Loss/(Gain)

Net Actuarial Loss/(Gain) as at December 31				
Expected Present Value of Defined Benefit Obligation	2,456,177	1,854,163	1,919,184	1,986,640
Actual Present Value of Defined Benefit Obligation	1,786,769	1,854,163	1,919,184	1,986,640
Net Actuarial Loss/(Gain) as at December 31	(669,408)	-	-	-

* The expected December 31, 2021 PV DBO and CY 2021 defined benefit cost are calculated based on membership data at December 31, 2018 and management's best estimate assumptions at December 31, 2020.

** Projected CY 2022, 2023, and 2024 results are provided for informational purposes only. Significant changes such as re-negotiated benefits, increased benefit costs, or significant swings in demographics may require revised projections or a full actuarial review.

*** Based on exepcted benefits to be paid to those eligible for benefits.

rsmcanada.com

RSM

APPENDIX B BDR

North America Inc. –

PUC Full Absorption

Cost Allocation

Review

FULL ABSORPTION COST ALLOCATION REVIEW

Prepared for PUC Services Inc.
December 17, 2021

BDR NorthAmerica Inc.
416-807-3332

BDR

Table of Contents

EXECUTIVE SUMMARY

Introduction and Scope

The PUC group of companies is comprised of five (5) subsidiaries of the Corporation of the City of Sault Ste. Marie (the "City"). The group includes PUC Distribution Inc. ("PUCD"), which distributes electricity to residences and businesses within the boundaries of the City of Sault Ste. Marie, the Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township. PUCD is regulated by the Ontario Energy Board ("OEB"), and therefore requires approval from the OEB for rates charged to electricity consumers. Its most recent Cost of Service rate application, involving a full review of costs in support of the rates, was completed in 2018.

As is common for small and medium sized Ontario electricity distributors ("distributors" or "LDCs"), PUCD shares certain resources with affiliates in order to create economies of scale and scope. Benefits are created both when a distributor purchases services from affiliates and when a distributor sells services to affiliates and receives revenue to offset its costs. Within the PUC group, the sharing of services is achieved through PUC Services Inc. ("PUCS"), which provides a range of services to PUCD and other companies in the group, as well as to Public Utilities Commission (the "Commission"), a Municipal Services Board of the City. Water and wastewater services are also provided to the City.

PUCS employs all of the employees providing services to the PUC group. As well, PUCS owns all of the shared assets of the group, including vehicles, tools and equipment, information technology and systems, streetlights, etc. The arrangement is intended to create economies of scope and scale through the sharing of human and other resources. The costs incurred by the PUCS are recovered through charges made by PUCS to the affiliates, including PUCD.

PUCS provides both electricity billing to PUCD and water billing to the Commission through a shared system.

All the activities of the PUC group of companies are carried out in a shared building at 500 Second Line East, which is owned by PUCD. The portion of the building used by affiliates is made available by PUCD under a lease arrangement. The lease is priced to affiliates at fully allocated cost.

In August, 2021, in anticipation of PUCD's forthcoming cost of service application to the OEB, PUCS retained BDR to review the transfer pricing and inter-company cost allocations in the context of the current scope of shared services. During August and September, 2021, PUCS provided BDR with information about the current corporate structure, scope of shared services and the manner in which they are rendered and clarified any issues through discussion. In September and October, 2021, BDR conducted its analysis. This document is the Report of BDR resulting from that review.

Summary of Conclusions as to Transfer Pricing Methodology

The following table ES-1summarizes the services ***provided by PUCS to PUCD.*** All of the pricing is at fully allocated cost. The table shows, for each type of service, the allocation method used, and BDR's comment or recommendation.

The methodology can be summarized as follows:

For certain business functions an allocation or direct assignment approach is identified. These include:

- Operations;
- Customer Service;
- Credit and Collections;
- Vehicles Operations;
- Regulatory; and
- Stores, Warehouse and Procurement.

This provides an allocation of the dollar costs in each of these functions, and also an allocation of work time, or FTEs[1]. The allocated FTEs are then summed to provide a factor that is used to allocate the costs of resources and activities that support employees in their work ("Supporting Functions"). The number of users of each of the Supporting Functions is considered as reasonable, and in accordance with accepted principles of cost allocation, as an allocator of the costs of these functions.

Any costs incurred in a supporting function that can be directly identified to a specific business unit are charged directly to that business unit.

Supporting Functions include:

- Human Resources (recruitment, labour relations, benefits administration, training, etc.);
- Information and communications technology;
- Office space;
- Furniture and equipment;
- Payroll administration; and
- Accounting and Finance.

[1] Full Time Equivalents. FTEs as a measure may be a fraction. For example, if an employee works 40% of time for one business unit and 60% for another, this represents 0.4 FTE and 0.6 FTE, respectively. Similarly, a part-time employee working half of the normal full-time hours per week, would count as 0.5 FTE.

Vehicle costs are assigned to business units based on utilization records, at an hourly rate calculated to recover the total costs. Garage space costs are allocated based on the vehicle costs.

Procurement and warehousing costs, including the costs of the warehouse facility, are allocated on the basis of the value of goods in inventory.

Insurance premiums are broken down to the business units by the insurer and charged to the business units accordingly.

Account interest is allocated by the monthly balances of each business unit's account.

The costs of the Board of Directors of PUCS are allocated based on the level of activity of the Board related to each business unit. Costs of the Boards of PUCD and the other affiliates, and of the Commission are not shared, and are therefore directly assigned.

Table ES-1 summarized the allocation methodology used, and the prior methodology, by type of cost. ***All of the currently used methodologies are considered by BDR to be reasonable and in accordance with accepted principles of cost allocation***.

For expense items, the cost being allocated is the annual expense. For assets, the cost being allocated is "fully allocated cost," consisting of depreciation expense plus cost of capital at the OEB-approved weighted average rate, applied to the book value, net of accumulated depreciation, of the asset. This is unchanged from the previous methodology.

Table ES-1: Services Provided by PUCS to PUCD

Nature of Service	Allocation Method Used	Method Previously Used
A. Direct Functions		
Operations, Non-Supervisory	Timesheets, specifying the business unit served. Effectively a direct assignment of costs.	Same as current method
Operations Supervision and Management	Allocation in proportion to Operations Non-Supervisory	Budgeted allocation
Customer Service Non-Supervisory	Total hours, allocated by number of customer accounts	Same
Customer Service Supervision and Management	Total hours, allocated by number of customer accounts	Same
Credit and Collections	Allocated by bad debt expense.	Same

Table ES-1: Services Provided by PUCS to PUCD		
Nature of Service	**Allocation Method Used**	**Method Previously Used**
Regulatory, All FTEs	No activities identifiable with affiliates; therefore 100% assigned to PUCD	Same
Stores, Warehouse and Procurement, All FTEs	Value of Inventory Issued	Same
Accounting and Finance	All employee FTEs Contractor labour excluded.	A&G factor based on labour review, including contractors.
Furniture, fixtures, and equipment	All employee FTEs Contractor labour excluded.	Direct labour hours
Land, buildings, and improvements, office	All employee FTEs Contractor labour excluded.	Direct labour hours
Human Resources	All employee FTEs Contractor labour excluded.	A&G factor based on labour review, including contractors.
Information technology, other than directly assigned costs	All employee FTEs Contractor labour excluded.	A&G factor based on labour review, including contractors.
Payroll Administration	All employee FTEs Contractor labour excluded.	A&G factor based on labour review, including contractors.
Vehicles and equipment	Recorded vehicle usage, applied to average hourly cost for recovery	Same
Garage building space	As allocation of cost of vehicles	Direct labour hours
Procurement, Stores and Warehouse, including Building Space	By value of issued inventory.	Department expenses by value of materials. Building space by direct labour hours.
Insurance	Designated by the insurer to business units. Direct assignment.	Same

The only charge made from PUCD to PUCS is for leasing the building at 500 Second Line East, which is owned by PUCD and utilized by the employees of PUCS in providing all of the listed services to the PUC group and the Commission.

Historically, PUCD has charged PUCS for the building at fully allocated cost (depreciation expense, plus the OEB approved cost of capital applied to the undepreciated costs).

Since there is a competitive market for commercial real estate, Section 2.3.3 of the OEB's Affiliate Relationships Code governs the pricing of this service. Specifically, Section 2.3.3.6 states that where, as in the case of this building, the service is being provided by the utility to affiliates, the transfer price must be at least ***the greater of*** the market price or fully allocated cost.

As a result, at the advice of BDR, PUCS sought a market rate report, and compared the market rates with the current fully allocated cost. The result was that at present, fully allocated cost exceeds the market rate. To comply with the ARC, the building will therefore continue to be priced at fully allocated cost for 2022. PUCS will continue to monitor market rates from time to time, so that pricing may transition to a market basis once market rates exceed fully allocated cost.

For allocation of the building cost among affiliates, the allocator is Operations FTE hours, for all departments with operations out of 500 Second Line. This results in water and wastewater treatment and environmental operations being excluded from an allocation, since those functions have their own facilities.

This is the same methodology used in the past, with updates to most currently available payroll hours data.

In the past, lease charges were at cost, including depreciation expense and cost of net invested capital at the OEB-approved rate.

1 SCOPE OF STUDY

PUCD is an electricity distributor licensed by the OEB to provide service to consumers within the boundaries of the City of Sault Ste. Marie, the Batchewana First Nation (Rankin Reserve), Prince Township and parts of Dennis Township.

The OEB, which regulates Ontario LDCs, has a mandate to protect the interests of distribution ratepayers by ensuring that rates are just and reasonable. Since affiliate transactions provide a potential opportunity for a shareholder to benefit inappropriately at the expense of electricity ratepayers, the OEB has implemented an Affiliate Relationships Code ("ARC") that establishes requirements for affiliate transactions. The nature and magnitude of affiliate transactions may be reviewed by the OEB on a compliance basis, and the appropriateness of costs and revenues from affiliate transactions may also be scrutinized as part of the LDC's distribution rate application.

As is common for small and medium sized Ontario electricity distributors ("distributors" or "LDCs"), PUCD shares certain resources with affiliates in order to create economies of scale and scope. Benefits are created both when a distributor purchases services from affiliates and when a distributor sells services to affiliates and receives revenue to offset its costs. Within the PUC group, the sharing of services is achieved through PUC Services Inc. ("PUCS"), which provides a range of services to PUCD and other companies in the group, as well as to Public Utilities Commission (the "Commission"), a Municipal Services Board of the City. Water and wastewater services are also provided to the City.

PUCS employs all of the employees providing services to the PUC group. As well, PUCS owns all of the shared assets of the group, including vehicles, tools and equipment, information technology and systems, streetlights, etc. The arrangement is intended to create economies of scope and scale through the sharing of human and other resources. The costs incurred by the PUCS are recovered through charges made by PUCS to the affiliates, including PUCD.

PUCS provides both electricity billing to PUCD and water billing to the Commission through a shared system.

All the activities of the PUC group of companies are carried out in a shared building at 500 Second Line East, which is owned by PUCD. The portion of the building used by affiliates is made available by PUCD under a lease arrangement. The lease is priced to affiliates at fully allocated cost.

Costs incurred by PUCS for its services are directly assigned to the user company where appropriate, and otherwise allocated using a methodology established in 2007. Since then, some changes in the application of the methodology have been necessary to reflect the fact that the corporate structure (number and type of business units) has changed.

The methodology can be summarized as follows:

- Costs that can be specifically identified as incurred to the benefit of one affiliate are directly assigned to that affiliate. This includes external costs and costs identified through the system of work orders to which some employees charge their time.
- Costs that are incurred on a shared basis and therefore cannot be identified as incurred for one specific affiliate are allocated to the affiliates based on an allocation factor.

- PUCS has developed allocation factors for each of the following cost pools: billing and customer service; collections; administration; building operations and maintenance; and building asset. The allocation factors are then applied to the costs in each of the related USOA accounts.

It is estimated that 69% of the costs of services provided by PUCS to PUCD is charged on a direct basis, and 31% is allocated using allocators that reflect cost causality.

In August, 2021, in anticipation of PUCD's forthcoming cost of service application to the OEB, PUCS retained BDR to review the transfer pricing and inter-company cost allocations in the context of the current scope of shared services. During August and September, 2021, PUCS provided BDR with information about the current corporate structure, scope of shared services and the manner in which they are rendered and clarified any issues through discussions between PUCS Management and BDR. In September and October, 2021, BDR conducted its analysis. This document is the Report of BDR resulting from that review.

In the course of the study, BDR was provided by Management with information as to the nature of the shared services and the 2007 methodology. All information was clarified through conversations with Management. BDR has not independently verified the provision of any services, the level of activity, the costs, or the value of any service.

All of the functions for which costs are allocated by PUCS to PUCD are part of the normal scope of activity of a local distribution company, and necessary to provide service to consumers. Through discussions with management, BDR ascertained that none of these functions duplicate a service that is self-supplied or otherwise procured by PUCD.

This report and its conclusions are the result of a review of the organization structure of the PUC group of companies, the number and activities of those companies, and the corporate approach to delivery of resources and services as at the time of the review. Management has advised BDR that while these factors may change over time, it intends to maintain a consistent approach toward the provision of shared services to maximize economies of scale and scope, and toward the allocation of the costs of those services among the companies.

2 STRUCTURE OF THE ORGANIZATION

The Corporation of the City of Sault Ste. Marie is the sole shareholder of PUC Services Inc. (PUCS) and PUC Inc., a holding company. PUC Distribution Inc. is a wholly owned subsidiary of PUC Inc. The other subsidiaries of PUC Inc. are:

- Northern Waterworks Inc., located in Red Lake, Ontario, a water, and wastewater management company providing services to Municipal, First Nation and Industrial clients; and
- 17 Trees Inc., which provides vegetation management services to its 3-way ownership partners, PUCD, Greater Sudbury Utilities Inc. and North Bay Hydro Services Inc.

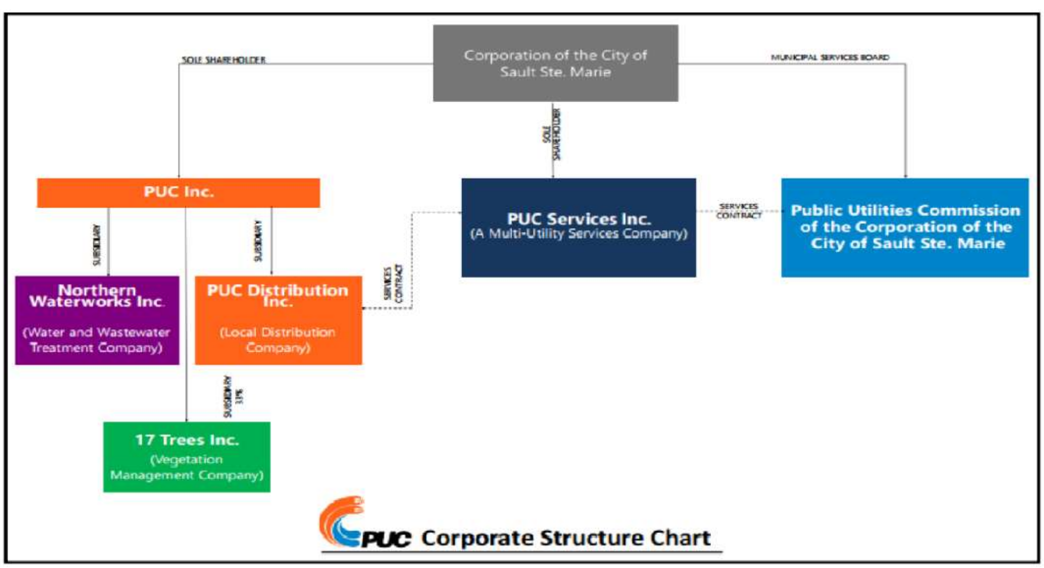
PUCS provides administrative services to 17 Trees Inc. and allocates a portion of shared administrative costs to 17 Trees Inc. for those services.

Northern Waterworks Inc. is a stand-alone company that provides its own administrative services and is therefore not allocated a share of administrative service costs from PUCS. If this arrangement changes in the future, PUCS will revise allocations accordingly, consistently with the allocation methodology.

The structure also includes the Public Utilities Commission, which provides water and wastewater services in the community. The Commission receives administrative services from PUCS and is allocated a share of costs for these services.

It is anticipated that as PUC's group of companies grows, this methodology will apply to include future businesses.

Figure 2.1 – Corporate Organization Structure of PUCD and Affiliates



3 OVERVIEW OF INTER-AFFILIATE SERVICES

3.1 *Shared Corporate Services*

The ARC, in providing direction as to inter-affiliate transfer pricing, provides the following important definition:

> "shared corporate services" means business functions that provide shared strategic management and policy support to the corporate group of which the utility is a member, relating to legal, regulatory, procurement services, building or real estate support services, information management services, information technology services, corporate administration, finance, tax, treasury, pensions, risk management, audit services, corporate planning, human resources, health and safety, communications, investor relations, trustee, or public affairs".[2]

Section 2.3.5 of the ARC provides that fully allocated cost-based pricing is the appropriate treatment for these costs.

PUCD receives shared corporate services from PUCS.

3.2 *Other Services Provided by PUCS to PUCD*

3.2.1 Operations of PUCD and the Commission

Employees performing distribution operations functions for PUCD are a service provided by PUCS. Since these costs are specifically identified through the corporate system as related to the operations of PUCD, they are charged to PUCD directly as incurred, and are not an allocated shared cost.

BDR considers that the direct assignment of a cost incurred for the benefit of a specific business unit is cost based and consistent with accepted cost allocation methodology.

The time of operation's employees, in terms of FTEs, is computed and becomes part of the FTE factor used to allocate the costs of Supporting Functions.

3.2.2 Billing and Customer Service

PUCS provides billing and customer service activities on a shared basis to PUCD in respect of electricity customer service and billing, and to the Commission in respect of water services and billing. Section 4.3 of this report addresses billing services. No

---

[2] ARC, Section 1.2.

other business units require the customer service and billing activities of PUCS. Billing and customer service is not a "shared corporate service" within the meaning of the ARC.

3.2.3 Vehicles

All of the vehicles used by business units are owned by PUCS. Vehicles are not a "shared corporate service" within the meaning of the ARC. Vehicle costs, like operations labour cost, is directly assigned according to recorded vehicle usage. Hourly rates for vehicle usage are established on a cost recovery basis.

3.3 *Shared Facility Owned by PUCD*

PUCD owns a building which is used in providing directly assignable and shared services to all of the business units. The basis of charges to affiliates for use of the building and vehicles is discussed in Section 4.4.

4 TRANSFER PRICING OF SHARED CORPORATE SERVICES

4.1 *Adherence to Fully-Allocated Cost Approach*

Pricing for all of the "shared corporate services" is cost-based, as required by the ARC. In reviewing the transfer pricing for the cost-based services, consideration was given to whether the total amounts are determined on the appropriate basis (i.e. cost as incurred, without arbitrary "markup," but including, where applicable, depreciation, return on assets, and any payments in lieu of tax attracted by the return).

Staff within PUCS is organized functionally, with departmental costs accumulated for allocation. For each of the shared corporate services, costs of shared resources and activities are allocated on a basis intended to reflect the use of the service by the business unit.

Activities that are carried out in PUCS, but which are used by only one business unit (rather than shared) are specifically identified and the costs are passed through to that business unit as incurred (i.e., directly assigned). As a result, certain costs (for example, membership in the Electricity Distributors Association and costs associated with compliance with regulation by the OEB) are borne 100% by PUCD. If a cost is specifically incurred for the benefit of a business unit other than PUCD, this methodology results in PUCD being excluded from sharing in that cost.

4.2 *Allocation of Specific Corporate Shared Services*

4.2.1 Information Technology and Telephone Services

Costs of this function were first identified to the following categories: workstation hardware; corporate systems other than SCADA; and SCADA systems.

SCADA systems for the electricity system and the water/wastewater systems are separate and identifiable in the accounts. As costs are incurred for upgrades to these systems, they are identified as for the electricity system or for the water system. Electricity-related SCADA costs are directly assigned to PUCD. Water-related SCADA costs are directly assigned to and recovered from the Commission.

BDR considers this treatment to be in accordance with accepted principles of cost allocation.

All other IT is considered a Supporting Function.

Each employee of PUCS has a personal workstation and access to the corporate IT systems. Management advised BDR that the hardware and local software associated with an employee who works mainly from a desk (management, supervisory, administrative, and customer service employees) has a current average cost of acquisition of $2,600. The cost of hardware and local software for an employee who works mainly from a vehicle (field staff) averages $2,000.

At present, all IT costs are allocated following the allocation of employee labour. BDR discussed with Management the possible refinement of a weighting factor that would account for the differential in per-employee workstation costs. Management advised that no material difference resulted from this addition to the computation, while adding more administrative effort to the allocation. ***BDR therefore considers continuation of the allocation based on labour, to be reasonable.***

For major systems and hardware, PUCS allocates costs following the allocation of the employees (FTEs), as the systems support the employees in their work for all business units.

BDR considers this treatment to be in accordance with accepted principles of cost allocation.

4.2.2 Executive and Board of Directors

The CEO and executive team charge their time to an administrative cost pool. This cost pool is then allocated to the companies in the PUC group following the allocation of all other FTEs.

Management has advised BDR that the executive leaders spend the majority of their time on activities that cannot be clearly identified with only one business unit, and as is common for these positions, are challenged in recording time by frequent interruptions and short-duration activities. They therefore consider that a measure of the activity in the business units they lead constitutes the fairest allocator for their time. Such a measure of activity is the FTEs of other staff as allocated to each business unit.

BDR considers this treatment to be reasonable in the circumstances, and in accordance with accepted principles of cost allocation.

The Board of Directors charge their time according to the meetings and time they spend directly to the company in the PUC group. Certain Board members may sit on more than one board, splitting their time accordingly.

BDR considers this treatment to be in accordance with accepted principles of cost allocation.

4.2.3 Insurance

Insurance premiums are identified by the insurer as associated with each of the business units, and then directly assigned to the business units by PUCS.

In BDR's view, direct assignment is the preferred treatment of costs where possible.

4.2.4 Payroll

Activities of the payroll administration support the employees and are therefore considered a Supporting Function and allocated on the basis of total FTEs.

On review, BDR considers that allocation based on employees reflects cost causation with respect to this function and is consistent with accepted principles of cost allocation.

4.2.5 Regulatory

This function provides the affiliates with all services related to compliance with regulation and licensing by the OEB. There is typically no activity with regard to maintaining licensing for the generation and competitive services business units, therefore the costs of this function can be attributed 100% to PUCD. An allocation of 100% of the regulatory costs to PUCD can therefore be considered to accord with time spent.

BDR considers that the allocation of costs of the regulatory function to PUCD is appropriate and consistent with accepted principles of cost allocation.

4.2.6 General Financial Services

These services comprise accounting, treasury, accounts payable and receivable, financial reporting, and audits.

Where possible, PUCS identifies any costs that can be directly assigned to an affiliate, i.e., audit fees. However, most activities in this category provide value to multiple business units as they are carried out and cannot be directly assigned to individual business units. Several possible measures of level of activity of the business units were considered, and none appear to be more clearly related to cost causation than staffing levels.

Therefore, activities of the accounting and finance resources support the employees are considered a Supporting Function and allocated on the basis of total FTEs.

BDR considers that the time estimation approach is reasonable under the circumstances and reflects accepted principles of cost allocation

4.2.7 Procurement and Stores Services

A percentage of the value of goods in inventory is applied, to recover the cost of stores services and procurement.

BDR has concluded that an allocation based on the value of issued inventory is reasonable in the circumstances, when applied to stores services and procurement.

4.2.8 Human Resources

Services provided by this department include employee records, labour relations, union contract administration, salary administration, staff training, staff recruitment, human rights management, and job evaluation administration. The Human Resources activity is considered a Supporting Function by PUCS.

BDR discussed with Management whether specific program or service costs could be directly identified and assigned among the business units. Management considered that doing so for some costs, combined with an FTE-based allocation of other costs for similar and related activities, would not result in an overall allocation reflective of the value that each business unit receives from the Human Resources function.

Therefore, all Human Resources costs are allocated to business units according to FTEs.

On review, BDR concurs with the view of Management as to specific identification of some components of the cost and considers that the costs of this function are causally related to the employees as a resource for each affiliate's business. Therefore, this allocation approach is reasonable and consistent with accepted principles of cost allocation.

4.3 *Customer Services Related to Billing*

PUCS provides billing services to PUCD in respect of electricity services, and to the Commission in respect of its water and wastewater services. A shared call centre responds to customer inquiries about billing, account administration and related matters. Bills are rendered monthly and include both electricity and water services to all customers that receive both services. A shared customer information system maintains customer account and billing records and computes bills.

The current methodology being used is to allocate in proportion to number of accounts for each service.

In proposing a cost allocation approach related to cost causation, it is important to start from an understanding that "billing and customer service" as a line item for reporting purposes is in fact the aggregate of a number of components that are different as to causation.

The initial step in addressing each subcomponent was to answer the question of whether costs could be directly identified as attributable to either electricity or water. If such an identification could be made, that information was used to assign the cost directly.

For the other subcomponents, the major factor or combination of factors in cost causation was identified by considering the nature of the function. Generally, costs related to maintenance of billing records, collecting, and processing of billing information, bill computation, and payment processing are related to number of bills as a causation factor. In the case of PUCD and the Commission, each renders a bill to each customer on a monthly basis. Therefore, the ratio of number of bills is the same as the ratio of number of accounts.

For bill printing and delivery, some LDCs have historically taken account of such factors as printed lines or space on the bill taken up by information related to each service. This count or allocation of page space would then be used to allocate the costs of stationery for billing and mailing costs.

In recent years, customers are gradually accepting electronic billing and bill delivery in substitution for printing and mailing. While this transition is not complete, it is underway, and electronic delivery will clearly dominate in the future. For a bill rendered and delivered electronically, the physical size and weight of a printed document is no longer as relevant to costs. BDR therefore concludes that such a refinement would not significantly enhance the quality of allocation of billing costs.

PUCS maintains a call centre that receives and handles calls related to customer account support and bill inquiry. In BDR's opinion the most accurate approach in cases of a shared call centre is to be able to track the number and length of calls to each service, as a means to develop an allocation factor. BDR has discussed with Management and determined that PUCS does not have such a system. Furthermore, Management is of the view that calls could not be identified accurately as to the service being questioned, even if a tracking system were in place.

On this basis, it is not possible at present to develop an allocator that is more refined than the number of accounts for each of the two services.

In summary, it is BDR's opinion that use of the number of accounts as the cost allocator for all cost components of the customer service and billing function is reasonable in the circumstances, and consistent with accepted principles of cost allocation.

Customer service FTEs as determined by this method form part of the allocation factor for Supporting Functions.

4.4 *Collections and Bad Debts*

These costs are being allocated by a factor derived from the bad debt expense associated with each of electricity service and water services.

BDR considers this method to be reasonable and consistent with accepted principles of cost allocation.

4.5 *Vehicles*

The business units make use of vehicles owned by PUCS. Management is proposing fully-allocated cost as the basis for pricing of this service to PUCD.

Costs are allocated by applying an hourly charge-out rate to all vehicle usage. When an employee logs time to the work order system, the associated use of vehicle is tracked by work order within the business units. Rates are set to recover actual costs when applied to all vehicle hours, where actual cost includes fuel, maintenance, and amortization, and cost of capital based on the OEB-approved rate of return applied to the net book value of the assets. Different rates are set for each of several vehicle classes, based on review by Finance staff as to the relative cost of each vehicle class.

In discussion with Management, BDR confirmed that PUCS does not use contractor-provided work vehicles except in the case of a vacuum truck as required, and therefore has no information as to the pricing that might be offered for these services in its local area. Vehicles are purchased by PUCS at a competitive market price.

The allocated vehicle usage cost is used to allocate the building costs for the garage.

BDR concludes that cost is the appropriate basis for pricing for the use of PUCS's vehicles by business units since the acquisition cost of vehicles is a market price. The allocation of costs based on hourly use, at rates that reflect the costs of vehicle classes, is reasonable and in accordance with accepted principles of cost allocation. BDR also considers vehicle usage cost as a reasonable basis for allocation of building costs for the garage.

4.6 *Furniture and Fixtures*

Office furniture. equipment and fixtures are considered a Supporting Function and allocated based on FTEs.

BDR considers this method to be reasonable and consistent with accepted principles of cost allocation.

4.7 *Building*

4.7.1 Distribution Buildings

All buildings other than 500 Second Line East are owned by PUCD and fully utilized for purposes of the electricity distribution activity, and the costs are fully included in the distribution revenue requirement. No transfer pricing is applicable for these facilities. PUCD does not use, and is not allocated costs for, buildings owned by any of its affiliates or by the City.

4.7.2 Head Office and Service Centre Complex

(a) Transfer Pricing from PUCD to PUCS

PUCD owns the head office and service centre complex at 500 Second Line East. Space in this building is used by the employees of PUCS in performing direct and shared services for all of the business units. The space consists of office, garage, and warehouse areas.

PUCD leases a portion of 500 Second Line East to PUCS. Historically, the lease pricing from PUCD to PUCS was determined on a cost basis, including annual amortization and cost of capital. Cost of capital was determined by applying the pre-tax weighted cost of capital, as most recently approved for PUCD by the OEB, by the net book value of the asset.

Since there is a competitive market for commercial real estate, Section 2.3.3 of the OEB's Affiliate Relationships Code governs the pricing of this service. Specifically, Section 2.3.3.6 states that where, as in the case of this building, the service is being provided by the utility to affiliates, the transfer price must be at least ***the greater of*** the market price or fully allocated cost.

As a result, at the advice of BDR, PUCS sought a market rate report, and compared the market rates with the current fully allocated cost. The result was that at present, fully allocated cost exceeds the market rate. To comply with the ARC, the building will therefore continue to be priced at fully allocated cost for the immediate future. PUCS will continue to monitor market rates from time to time, so that pricing may transition to a market basis once market rates exceed fully allocated cost.

In BDR's view, use of fully allocated cost as the basis for pricing of the building by PUCD to PUCS is in compliance with the ARC, since fully allocated cost is presently above market price. In the future, if market price comes to exceed fully allocated cost, then market price should apply.

(b) Allocation of Building Lease and Operating Costs

For recovery of the building costs by PUCS to each of the business units, the lease cost is allocated separately for the office space, the garage space, and the warehouse space.

Office space is considered a Supporting Function and allocated in accordance with the FTE methodology. The allocator is Operations FTE hours, for all departments with operations out of 500 Second Line. This results in water and wastewater treatment operations being excluded from an allocation, since those functions have their own facilities.

This is the same methodology used in the past, with updates to most currently available payroll hours data.

Garage space is allocated in proportion to the allocation of vehicle costs. Warehouse space is allocated in proportion to the allocation of procurement and stores operating costs.

Building operating costs including property taxes, electricity, heating, water and sewer, insurance, janitorial, repairs and maintenance were determined on a square footage basis and charged in addition to the cost-based lease charge from PUCD.

BDR concludes that the allocation methodology reflects cost causation and is therefore reasonable and consistent with accepted principles of cost allocation.

Consulting Team Curricula Vitae

In alphabetical order:
Michael J. Roger
Paula Zarnett

MICHAEL J. ROGER

34 King Street East, Suite 600 | Toronto, ON M5C 2X8 | 905 731 9322 | mroger@elenchus.ca

---

ASSOCIATE, RATES AND REGULATION

Michael has over 40 years of experience in the electricity industry dealing in areas of finance, cost allocation, rate design and regulatory environment. Michael has been an expert witness at numerous Ontario Energy Board proceedings and has participated in task forces dealing with his areas of expertise. Michael is a leader and team player that gets things done and gets along well with colleagues.

PROFESSIONAL OVERVIEW

Elenchus **2010 - Present**
Associate Consultant, Rates & Regulation

- Provide guidance on the Regulatory environment in Ontario for distributors and other stakeholders, with particular emphasis on electricity rates in Ontario and the regulatory review and approval process for cost allocation, rate design and special studies such as Working Capital Allowance and shared services studies. Prepare and defend related evidence. Appear as expert witness at regulatory proceedings.
- Some of the clients that Michael provides advice include: Hydro Quebec Energy Marketing Inc., GTAA, Ontario Energy Board, City of Hamilton, Hydro One Transmission, Powerstream, Hydro Ottawa, Ontario Power Generation, Veridian, SaskPower, British Columbia Utilities Commission and APPrO.

Hydro One Networks Inc. **2002 - 2010**
Manager, Pricing, Regulatory Affairs, Corporate and Regulatory Affairs

- In charge of Distribution and Transmission pricing for directly connected customers to Hydro One's Distribution system, embedded distributors and customers connected to Hydro One's Transmission system.
- Determine prices charged to customers that conform to guidelines and principles established by the Ontario Energy Board, (OEB).
- Provide expert testimony at OEB Hearings on behalf of Hydro One in the areas of Cost Allocation and Rate Design.

- Keep up to date on Cost Allocation and Rate Design issues in the industry.
- Ensure deliverables are of high quality, defensible and meet all deadlines.
- Keep staff focused and motivated and work as a team member of the Regulatory Affairs function. Provide support to other units as necessary.

Ontario Power Generation Inc. **1999 - 2002**
Manager, Management Reporting and Decision Support, Corporate Finance

- Produce weekly, monthly, quarterly and annual internal financial reporting products.
- Input to and coordination of senior management reporting and performance assessment activities.
- Expert line of business knowledge in support of financial and business planning processes.
- Coordination, execution of review, and assessment of business plans, business cases and proposals of an operational nature.
- Provide support to other units as necessary.
- Work as a team member of the Corporate Finance function.

Ontario Hydro **1998 - 1999**
Acting Director, Financial Planning and Reporting, Corporate Finance

- Responsible for the day to day operation of the division supporting the requirements of Ontario Hydro's Board of Directors, Chairman, President and CEO, and the Chief Financial Officer, to enable them to perform their due diligence role in running the company.
- Interact with business units to exchange financial information.

Financial Advisor, Financial Planning and Reporting, Corporate Finance **1997**

- Responsible for co-ordinating Retail, Transmission, and Central Market Operation divisions' support of Corporate Finance function of Ontario Hydro to ensure financial information consistency between business units and Corporate Office, review business units compliance with corporate strategy.
- Provide advice to Chief Financial Officer and Vice President of Finance on business unit issues subject to review by Corporate Officers.
- Participate or lead task team dealing with issues being evaluated in the company.
- Supervise professional staff supporting the function.
- Co-ordinate efforts with advisors for GENCO and Corporate Function divisions to ensure consistent treatment throughout the company.

Section Head, Pricing Implementation, Pricing **1986 - 1997**

- Responsible for pricing experiments, evaluation of marginal costs based prices, cost-of-service studies for municipal utilities, analysis and comparison of prices in the electric industry, rate structure reform evaluation, analysis of cost of servicing individual customers and support the cost allocation process used to determine prices to end users.

- Responsible for the derivation of wholesale prices charged to Municipal Electric Utilities and retail prices for Direct Industrial customers, preparation of Board Memos presented to Ontario Hydro's Board of Directors and support the department's involvement at the Ontario Energy Board Hearings by providing expert witness testimony.

Section Head (acting), Power Costing, Financial Planning & Reporting, Corporate Finance **1994 - 1995**

- Responsible for the allocation of Ontario Hydro's costs among its customer groups and ensure that costs are tracked properly and are used to bill customers.
- Maintain the computer models used for cost allocation and update the models to reflect the structural changes at Ontario Hydro.
- Participate at the Ontario Energy Board Hearings providing support and expert testimony on the proposed cost allocation and rates.
- Provide cost allocation expertise to other functions in the company.

Additional Duties **1991**

- Manager (acting) Rate Structures Department.
- Review of utilities' rates and finances for regulatory approval.
- Consultant: Sent by Ontario Hydro International to Estonia to provide consulting services on cost allocation and rate design issues to the country's electric company.

Analyst, Rates **1983 - 1986**

- In charge of evaluating different marketing strategies to provide alternatives to customers for the efficient use of electricity.
- Co-ordinate and supervise efforts of a work group set up to develop a cost of service study methodology recommended for implementation by Municipal Electric Utilities and Ontario Hydro's Rural Retail System.
- Provide support data to Ontario Hydro's annual Rate Submission to the Ontario Energy Board.
- Participate in various studies analysing cost allocation areas and financial aspects of the company.

Forecast Analyst, Financial Forecasts **1980 – 1983**

- Evaluating cost data related to electricity production by nuclear plants and preparing short term forecasts of costs used by the company. Maintain and improve computer models used to analyse the data.
- Review Ontario Hydro's forecast of customer revenues, report actual monthly, quarterly and yearly results and explain variances from budget.
- Support the development of new computerized models to assist in the short-term forecast of revenues.

Project Development Analyst, Financial Forecasts **1979 - 1980**

- In charge of developing computerized financial models used by forecasting analysts planning Ontario Hydro's short term revenue and cost forecasts and also in the preparation of Statement of Operations and Balance Sheet for the Corporation.

Assistant Engineer – Reliability Statics, Hydroelectric Generations Services **1978 – 1979**

- In charge of analysing statistical data related to hydroelectric generating stations and producing periodic report on plants' performance.

ACADEMIC ACHIEVEMENTS

1977	Master of Business Administration, University of Toronto. Specialized in Management Science, Data Processing and Finance. Teaching Assistant in Statistics.
1975	Bachelor of Science in Industrial and Management Engineering, Technion, Israel Institute of Technology, Haifa, Israel.

PAULA ZARNETT

Paula Zarnett has more than 35 years broadly based experience specializing in regulatory compliance, regulated tariffs and pricing issues for electricity and gas utilities. She has been responsible for design and implementation of a wide variety of innovative rates including time of use, both for large industrial and for residential customers, curtailment incentives, and special rates for load retention. She has performed customer cost allocation studies for utilities serving customers with electricity, natural gas and steam, and studies for allocation of shared corporate costs and transfer pricing for electricity and natural gas utilities.

Following a series of rate and cost allocation specialist positions first in the natural gas sector and then in the electricity sector, she was promoted to the position of Manager of Marketing and Energy Management at Toronto Hydro. There, her responsibilities included all rate and regulatory issues, customer research including load research and forecasting, and customer program design with a focus on conservation and demand management.

In her consulting practice, Paula provides a variety of advisory and analytical services to energy sector clients with a focus on rate approvals and issues impacted by regulatory policy and process. Her work includes business case and project feasibility analysis, cost allocations and pricing designs, energy sector mergers and acquisitions, and expert testimony before regulators. She is a skilled hands-on analyst and facilitator of cross-functional project teams. She was an instructor in Cost Allocation and Rate Design at CAMPUT's Energy Regulation Course, 2006, 2007 and 2008. She has been accepted as an expert witness in cost allocation in New Brunswick, Québec and Ontario.

She has performed assignments for clients in North America, China, Ghana, Barbados, and Turks and Caicos Islands.

	SELECTED EXPERIENCE BY SUBJECT AREA (INCLUDES PROJECTS UNDERTAKEN AS A CONSULTANT, AND IN THE COURSE OF RESPONSIBILITIES WITHIN ORGANIZATIONS)
Shared and Corporate Cost Allocation, Transfer Pricing	**Independent Electricity System Operator (Ontario)** – study to recommend allocation approaches for shared costs between core and non-core activities **Gazifère –** study to allocate shared costs between regulated and unregulated businesses (to Régie de l'Energie) **Greater Sudbury Hydro –** study to allocate costs of services purchased from affiliate (OEB) **Bluewater Power –** study to allocate costs of services provided to and purchased from affiliates (OEB) **Kingston Hydro –** study to review transfer pricing methodologies and allocation of shared costs for services provided by non-regulated affiliates. (OEB)

	FortisOntario and utility affiliates – Five studies to allocate corporate and shared costs among regulated and non-regulated affiliates (OEB) **EnWin Utilities** – study to allocate corporate and shared costs among corporate affiliates (OEB)
Customer Class Cost Allocation and Load Research	**Government of Turks and Caicos Islands** – study to allocate costs of service to customer classes and geographic zones, in connection with consideration of application for rate increase by the incumbent electric utility, FortisTCI; study included analysis of detailed load data **Municipal Utilities of New Brunswick –** advised the municipal utilities in their intervention in the application to NBEUB of NB Power, for approval of cost allocation methodology; assignment includes participation at preliminary stakeholder meetings on methodology; review and analysis of all filed material, assistance in development of interrogatories, advice on position and strategy for the intervention, work with legal counsel in developing cross examination of applicant and intervenor witnesses. (Matter 271) Also supported interventions by the municipal utilities, specifically related to issues of cost allocation, in NB Power's General Rate Application Matters 272, 336 and Matter 375 Also advised the municipal utilities in cost allocation and rate design hearings at NBEUB in 2005 and 2007; testified on their behalf before NBEUB on cost allocation in 2005. **Electricity Distributors Association –** advice, analysis, and representation at stakeholder processes with regard to proposed allocation by Hydro One Transmission of costs related to proposed new transmission facilities in southwestern Ontario **Rogers Cable and Communications Inc. –** represented this consumer stakeholder in a regulator-driven process to resolve issues in regulator-mandated methodology for the allocation of costs to street lighting and other unmetered loads **Toronto Hydro-Electric System** – Study to allocate the cost of service to customers that are individually metered suites in multi-unit residential buildings. **Rogers Cable and Communications Inc. –** represented a consumer stakeholder in a regulator-sponsored stakeholder process to determine a cost allocation methodology and analysis approach for information filings by all electric distribution utilities in Ontario. **Perth-Andover Electric Light Commission –** study to allocate the bundled costs of electricity service to customer classes and assess the impacts on cost allocation of changes to the wholesale rate structure. **Saint John Energy** – four (4) studies to allocate the bundled costs of electricity service to customer classes; one of these studies included

	analysis of metered system load profiles and publicly available typical customer profiles to develop demand allocation factors (most recent studies including load research data analysis). **Enwave District Energy Limited** – study to allocate costs of service for a district steam system as a basis for pricing redesign; study included analysis of detailed time-related customer consumption data as a basis for allocation of costs, as well as operating and financial data. **Toronto Hydro** – planning and execution of customer load research projects, including deployment of research metering, load data analysis and related customer research and surveys. **Toronto Hydro** – coordination of first comprehensive cost of service study, a one-year cross-functional project, including in-depth data collection, selection of allocation methodologies and development of computer-based analytical tools. Led subsequent updates and refinements to the study. **ICG Utilities Ltd.** – fully allocated cost of service studies for natural gas distribution systems in Manitoba and Alberta, including data analysis and development of computer-based analytical framework.
Testimony before Regulators	**ORAL:** **Gazifère Inc. –** testified to a study to allocate shared costs between regulated and unregulated businesses (to Régie de l'Energie) **Toronto Hydro-Electric System –** Testified before the Ontario Energy Board in support of the allocated costs of service to customers that are individually metered suites in multi-unit residential buildings. **Utilities Municipal of New Brunswick –** Testified before the New Brunswick Public Utilities Board in support of intervention in the Cost Allocation and Rate Design application of New Brunswick Power Distribution and Customer Service Corp.; and before New Brunswick Energy and Utilities Board in support of intervention in General Rate Application (GRA) of New Brunswick Power. **Rogers Cable and Communication Inc.** – Testified before Ontario Energy Board in support of consensus for treatment of certain unmetered electricity loads in the development of guidelines for electricity distribution rates. **ICG Utilities** testified in three hearings before British Columbia regulator (BCUC) on the subject of lead-lag studies. **WRITTEN ONLY:** **Independent Electricity System Operator (Ontario)** – study to recommend allocation approaches for shared costs between core and non-core activities

	Summerside Electric – expert study of Canadian precedents related to bypass by a load customer of a utility's system and charges. **Essex Power, Bluewater Power and Niagara-on-the-Lake Hydro** – expert testimony in support of intervention in the application to the Ontario Energy Board for approval of an acquisition by Hydro One Networks Inc. of Norfolk Power **Greater Sudbury Hydro** – study to allocate costs of services purchased from affiliate (OEB) **Bluewater Power** – study to allocate costs of services provided to and purchased from affiliates (OEB) **Kingston Hydro** – study to review transfer pricing methodologies and allocation of shared costs for services provided by non-regulated affiliates. (OEB) **FortisOntario** – Five studies to allocate corporate and shared costs among regulated and non-regulated affiliates (OEB) **EnWin Utilities** – study to allocate corporate and shared costs among corporate affiliates (OEB) **Ontario Power Authority** – model development and analysis in support of evaluation of a potential generation, transmission and demand response alternatives in York Region; report in support of generation alternative to the Ontario Energy Board.
Rate Designs and Pricing Studies	**Municipal Utilities of New Brunswick** – advised the municipal utilities and participated on their behalf in stakeholder sessions related to a rate design approval application by New Brunswick Power (Matter 357) **Canadian Federation of Independent Business** -- Advised and represented CFIB in stakeholder processes of the Ontario Energy Board to design electricity distribution rates applicable to all sizes of non-residential metered customers **Saint John Energy** – comprehensive recommendations to re-align rates to customer classes based on results of cost allocation study **IGPC Ethanol Inc.** – supported the intervention of this industrial consumer in the rate application of its gas supplier, Natural Resource Gas **Rogers Cable and Communications Inc.** – representation at Ontario Energy Board staff consultation process with regard to rate designs for Ontario's electric distribution utilities; development of policy and position documents, attendance at stakeholder meetings, analysis in support of positions on rate design for General Service classification and unmetered scattered loads; distribution cost allocation stakeholder process and 2006 distribution rate handbook.

City of Markham (Ontario) – recommendations for restructuring water and wastewater rates

Oklahoma Gas and Electric – review of results of residential time of use rate pilot including estimation of impact of the rate design on total customer consumption and peak hour consumption (load shifting).

Summerside Electric/City of Summerside – advisory and analysis service with regard to proposals of Maritime Electric for an Open Access Transmission Tariff.

Nova Scotia Department of Energy – advisory and analysis services to support intervention in Nova Scotia Power's request to the regulator for approval of a fuel adjustment mechanism.

BC Hydro – assisted a staff team in development of a Phase I report on long-term rate strategy; research on rate designs in several North American jurisdictions.

Energy East (RGE and NYSEG) – analysis as to the potential value of load shifting which might take place as result of rate-driven (time of use or critical peak pricing) programs supported by universal interval metering in the State of New York; regulatory precedents as to cost recovery for advanced metering and meter reading technology

East China Grid Company – advice in developing and simulating an unbundled electricity distribution tariff for Shanghai Municipal and four provincial electric power companies

British Columbia Ministry of Energy and Mines – advisory and due diligence services with regard to recommendations by the British Columbia Utilities Commission for implementation of proposed Heritage Contract and stepped rates to wholesale and industrial customers.

Perth-Andover Electric Light Commission – long-term rate strategy and detailed bundled retail rate designs for all electricity consumer classifications.

Volta River Authority (Ghana) – development of tariff structure and preliminary rates for open access use of the national electric transmission system in Ghana.

Enwave District Energy Limited – determination of appropriate customer classification and pricing design alternatives for a district steam system in a context of competitive electricity and gas markets and wider service choices for existing and potential customers.

Toronto Hydro – development and initial implementation of time of use rates for residential and large industrial customers; development of pricing strategies and policies for all customer classes.

	Toronto Hydro – development of all customer rate designs, implementation strategy, and preparation of annual submissions for approval of the rates. Managed a team of specialists in the preparation of associated detailed studies, load forecasts and load research. **ICG Utilities –** coordinated preparation of applications, supporting materials, and other aspects of regulatory process for regional gas utility managements, as member of a head office specialist team; provided expert technical services in rate design, cost allocation, and working capital allowance determination (lead-lag)
Regulatory and Industry Policy	**Ontario Energy Board** – cross-jurisdictional review and assessment of regulatory approaches to the issue of farm stray voltage across North-America **Ontario Energy Board –** comparison of heritage contracts and similar arrangements in leading jurisdictions **Ontario Energy Board –** identification of appropriate roles and responsibilities for the OEB under alternative industry and market structure scenarios, including default supply arrangements **Barbados Public Utilities Board** – study to recommend procedures, rules and systems for oversight of the natural gas sector by a new regulatory agency. **Electricity Distributors Association --** analysis of cash flow patterns of electricity distribution utilities in Ontario reflecting customer payment patterns and market settlement requirements **Electricity Distributors Association** – study to determine the financial benefit to municipalities of ownership of local distribution companies (LDCs). **National Grid Co. --** Assessment and overview report on regulatory framework and issues in Ontario. **Bruce Power** – Assessment and overview on industry structure, generation and transmission capacity, pricing and issues in New Brunswick **CMS Energy –** report on Ontario electricity industry structure, market, and regulatory environment, in support of decision to respond to RFP for new generation in the province **New Brunswick Municipal Electric Utilities Association** – cross jurisdictional survey with respect to policy as to regulation of municipal utilities and rural cooperatives.

	CAREER HISTORY
2001 – Present	**BDR** – consultant specializing in rate designs, cost and financial analysis, business planning and mergers and acquisitions in the energy sector
1998 – 2001	**In association with Acres Management Consulting** – consultant specializing in rate designs, cost and financial analysis, business planning and energy market restructuring issues.
1995 – 1998	**Toronto Hydro** – Manager, Marketing and Energy Management
1993 – 1995	**Toronto Hydro** – Special Assistant to the General Manager (responsible for organizational performance improvement initiatives)
1986 – 1992	**Toronto Hydro** – Supervisor of Rates and Cost Analysis
1984 – 1986	**Toronto Hydro** – Senior Rate Analyst
1981 – 1984	**ICG Utilities Ltd**. – Coordinator, Rate Administration
1979 – 1981	**H. Zinder & Associates Canada Ltd**., Senior Analyst
	EDUCATIONAL AND PROFESSIONAL QUALIFICATIONS
Degrees and Designations	CPA, CMA (Manitoba) University of Calgary, Masters of Business Administration (Finance) University of Toronto, Bachelor of Arts (Hon), Anthropology
Professional Association	Chartered Professional Accountants of Manitoba (CPA Manitoba)
Continuing Professional Development	Queens University School of Business, Marketing Program Queens University School of Business, Sales Management Program Society of Management Accountants of Canada—Customer Profitability Analysis Society of Management Accountants of Canada—Strategic Cost Management Society of Management Accountants – Auditing I Success Resources America – Train the Trainer Success Resources America – Leadership Summit Success Resources America – Ultimate Speaker Academy CPA Manitoba - Ethics
	PROFESSIONAL INVOLVEMENT
Teaching, Training ,and Industry Committees	Invited speaker at CAMPUT annual conference, 2019, on subject of recovery of disaster-related service restoration costs. Instructor in Cost Allocation and Rate Design for Annual Energy Regulation Course, CAMPUT (Canadian Association of Members of Public Utility Tribunals) 2006, 2007, 2008. Member and Vice-Chair, Electricity Distributors Association

	Commercial Members Steering Committee (2007 to 2014) Member – Ontario Energy Board Cost Allocation Working Group (2003 and 2005-6) Member – Ontario Energy Board Working Group on Cost Allocation for Unmetered Electricity Loads (2012-2013) Member – Municipal Electric Association Cost of Service Sub-Committee (1986-1988)

April, 2021

APPENDIX C

PUC Corporate

Purchasing Policy

1.0 PURPOSE

The Board of Directors of PUC Inc., PUC Services Inc., PUC Distribution Inc. and the Public Utilities Commission (collectively PUC) have the ultimate authority for all expenditures. The Boards delegate this authority to the President & Chief Executive Officer (CEO) through approved budgets or specific resolutions. This policy specifies the purchasing practices to be followed by all employees of PUC Services Inc. with respect to the procurement of goods and services for the operation of PUC.

2.0 SCOPE

This policy applies to all employees of PUC Services Inc.

3.0 OBJECTIVES

- To purchase for PUC, required goods and services and to dispose of unusable, obsolete, worn out or scrapped goods in accordance with PUC's policies and procedures.
- To ensure fair, open, transparent and accountable competitive processes are followed in the acquisition of goods and services from suppliers.
- To maintain the confidentiality of supplier information.
- To ensure compliance with all applicable laws (Ontario Disabilities Act, Discriminatory Business Practices Act, Occupational Health & Safety Act, etc.)
- Where practical, to promote standardization, partnership arrangements, joint purchases, and avoid unnecessarily restrictive specifications.
- As required, to provide goods and services to all user departments in the most expedient and economical manner, considering lifecycle cost, consistent with an ethical purchasing philosophy.
- To achieve harmonious, productive, working relationships with all departments or functions within PUC. The purchasing activities cannot be effectively accomplished solely by the efforts of the Purchasing Department. Collaboration with other departments and individuals within PUC is vital to the success of the business.
- To maintain adequate quality standards set in conjunction with user departments on materials and services in order to meet or exceed our customers' and regulatory requirements.
- To promote reduction in the amount of waste requiring disposal through the purchase of environmentally responsible goods and services.
- To promote the procurement of all goods and services from reputable and ethical vendors. The success of PUC depends on its skill in locating and/or developing vendors, analyzing vendor capabilities, and then selecting the appropriate vendor. Only if the final selection results in vendors who are both responsible and reliable will PUC obtain the items it needs at the best value.

- To maintain inventories at levels capable of sustaining operations without committing PUC to undue financial investments.

4.0 GUIDING PRINCIPLES

- PUC is committed to receiving the "best value and life cycle cost" for its money, i.e., to purchase the best services and products at the most competitive price. In order to leverage its resources to advance the community in which its customers live, PUC considers "best value" to include the generation of positive social benefits in addition to high quality and competitive price. PUC strives to enable local entities to compete for PUC contracts, provide opportunities for local entities to be successful bidders and to work with out-of-town suppliers to maximize the utilization of local resources.

- In accordance with PUC's Code of Conduct employees involved in the purchasing process may not accept gifts from vendors. Nominal promotional items such as pens, calendars, t-shirts, ball caps, etc. are excluded from this ban.

- Purchases of a personal nature that are not business related are prohibited. In accordance with PUC's Signing Authority Policy, no employee will solely approve their own purchases.

- In addition, the procurement process should follow the principles advocated by the Supply Chain Management Association of Canada.

- For greater clarity, if an employee has any pecuniary interest in relation to any purchase of goods or services, the employee shall immediately disclose the interest to their supervisor and shall not take part in the purchasing decision or in any way influence the purchasing decision.

- In the best interest of PUC Services Inc., the Purchasing Department reserves the right to question any purchase and ask for rationale and/or supporting documentation at any time.

5.0 HEALTH & SAFETY REQUIREMENTS

- All purchases must comply with all applicable health & safety standards, codes, regulations and organizational specifications.

- All suppliers of "controlled products" as defined by the Workplace Hazardous Materials Information System (WHIMIS) must meet the requirements of the Occupational Health & Safety Act, and are subject to the requirements of the Regulations for Industrial Establishments.

- Materials required for the electrical distribution system must be in accordance with Ontario Regulation 22/04 and PUC's Electrical Distribution Safety Program. (reference EDS-P10 Purchasing Approved Equipment). All materials and chemicals required for water distribution and water treatment shall meet the requirements of the Municipal Drinking Water License issued pursuant to the Safe Drinking Water Act.

- No new "designated product" will be purchased without knowledge of the Manager, Safety and Environment or his designate and the Joint Health & Safety Committee. See PUC's Workplace Hazardous Material Control Program.

- All contracts for services will comply with the Occupational Health & Safety Act and PUC's Health and Safety policies:
  - Safety Prequalification is the process used to minimize the amount of risk associated with hiring contractors. This process ensures each contractor demonstrates the basic general requirements to ensure workplace safety culture and to comply with the regulations put in place by the Ontario Occupational Health and Safety Act and its Regulations. See PUC's Contractor Safety Program document.
  - In addition, the hiring supervisor (requisitioner) is accountable to assess the potential safety risk associated with the work. Additional safety information may be needed depending on such risk level; this can be accomplished by completing the Contractor Checklist found in the Contractor Safety Program document.

6.0 GENERAL PURCHASING REQUIREMENTS

Value of Commitment		Purchase Method (minimum requirement)	Process Options
6.1	Over $100,000	Formal Competitive Bidding	Requisition/Purchase Order/Contract
6.2	$25,001 to $100,000	Formal request by invitation for quotation/proposal – written proposal to be signed and sealed or sent to purchasing dept. "bids" e-mail address (3 minimum) (invitation)	Requisition/Purchase Order
6.3	$2,500 to $25,000	Informal Request for quotation/proposal: • $2500-5000 - minimum one quote to be attached • $5000-25000 * must have minimum of three quotes **Exception with VP written approval*	Requisition/Purchase Order
6.4	Under $2,500	No Quotes	Credit Card/Petty Cash/Direct Purchase/Requisition/Purchase Order

All purchases will be completed by following the purchasing process as outlined in APPENDIX A.

Tendering will be carried out as per APPENDIX B.

6.1 Over $100,000 in value - Formal Competitive Bidding

PUC will call Tenders when the total expenditure of goods and services is estimated to be more than $100,000. Tenders may be called at a lesser dollar amount where deemed warranted.

In estimating the value of goods and services to determine if the purchase is within the tendering limit, the following criteria will be used:

- The expenditure must be related to a whole or complete job, item or service.
- The purchase must not be segmented or divided in a manner that would circumvent the tendering process.

The act of tendering is an important segment of PUC's Purchasing Policy in that it ensures the following:

- That PUC receives the benefit of competitive pricing.
- It makes the provision of goods and services to PUC available to a wide range of business organizations.

Split awards may be made when advantageous to do so.

When a tender is awarded a purchase order will be created to coincide with the signed contract.

Tenders will be issued where the goods and services are fairly well defined and generally commercially available. In these cases best value and life cycle costs will be the major determining factor. A scoring methodology will be established and documented prior to opening bids.

Professional services such as architects, engineers, banking, consultants, insurance brokers and adjusters and certain other goods and services such as computer hardware and software or property development cannot be as easily defined and specified as the procurement of other more generally commercially available goods and services. A Request for Proposal will be issued where the negotiation and award is based on demonstrated competence, professional qualifications and the technical merits of the submission at a fair price.

A Request for Proposal will follow the general procedures of the purchasing tender. The evaluation process for selection of the Supplier should be clearly outlined in each Request for Proposal. The two envelope method may be used for Request for Proposals where the true scope and complexity of the service is difficult to define in advance.

6.2 Purchases $25,001 to $100,000 in value - Request for Quotations

PUC will require a minimum of three (3) quotations when the total estimated expenditure for goods and services is estimated to be more than $25,000 but less than $100,001. The quotations will be in the form of a written Request for Quotes/Proposal. The quotations will be secured by the Purchasing Department and shall be in writing and sealed or sent to the purchasing department "bids" e-mail address. The quotes shall be analyzed by the requisitioning department who justify the selected quotation. If after reasonable effort only a lessor number of quotations are obtained, approval to proceed is required from the VP level. The quotations shall be retained by the Purchasing Department. The requisitioning department shall forward an approved requisition to the Purchasing Department to issue a purchase order.

6.3 Purchases $2,500 to $25,000 in value – Informal Request for Quotations

PUC will require a minimum of one (1) quote for purchases estimated to be $5,000 or less, and three (3) quotations when the total expenditure for goods and services is estimated to be more than $5,000 but less than $25,001. The quotations may be in the form of a Request for Quotes/Proposal or an informal solicitation of quotes. The quotations shall be in writing and be secured by the Requesting department or Purchasing department. The quotes shall be analyzed by the requisitioning department who justify the selected quotation. In the event of Sole Source situation or if after reasonable effort only a lessor number of quotations are obtained, approval to proceed is required from the VP level. The quotations shall be retained by the Purchasing Department. The requisitioning department shall forward an approved requisition, attaching all quotations, to the Purchasing Department to issue a purchase order.

6.4 Purchases under $2,500

The purchaser of goods or services under $2,500 must be able to demonstrate that the purchase was made at fair value. Purchases of goods in this cost range can be made using petty cash (small dollar amounts), PUC credit card (as per the terms of the Credit Card Policy), Direct Purchase or requisition/purchase order method. Requisitions must be approved as per PUC's Signing Authority Policy before a purchase order can be created. Direct Purchases, Credit Card purchases and Petty Cash purchases are subject to PUC's Signing Authority Policy.

- *Credit Card Purchases*

The purpose of the Credit Card is to provide an efficient, cost effective method of purchasing and processing small dollar or 'one off' type purchases. Items purchased with credit cards require appropriate supporting documentation and approvals and have specified dollar limits. (See PUC's Corporate Credit Card Policy)

7.0 OTHER PURCHASING PRACTICES

7.1 IT Purchases

All purchases of IT hardware, software and services must receive advisory approval from the Manager of IT and Communications in order to enable tracking of systems and to maintain Corporate IT standards.

7.2 Emergency Purchases

For a situation where immediate action is required to avoid jeopardizing operations, disrupting service to the public, or threatening the health and safety of staff or the public, purchases can be made by any method available. Subsequent to the emergency situation the purchaser shall provide written justification to their immediate supervisor for the purchase and the purchase will proceed through the normal approval process in accordance to the PUC's Signing Authority Policy before payment. Moving forward, consideration should be given to ensuring critical spares are established whenever possible.

7.3 Non-competitive Procurements

Excluding O.E.M. and standardized equipment Non-competitive procurement is only allowed in approved circumstances. Prior written approval is required for non-competitive purchases and must be attached to a purchase requisition (see APPENDIX C for Sole Source Approval Form). All sole source purchases under $5,000 must be approved by Purchasing. All sole source purchases exceeding $5,000 require the approval of the Divisional VP and Vice-President, Finance & Corporate Support. All sole source purchases exceeding $50,000 to be approved by President & CEO.

7.4 Excluded Purchases

The purchasing methods described in this policy do not apply to the items listed in APPENDIX D.

7.5 Electronic Requisitions and Approvals

Purchase requisitions are generated using the in-house requisitioning application (Cayenta) to initiate the purchasing process.

7.6 Consortiums/Co-Operative Purchasing

Cooperative purchasing or an arrangement between two or more entities (Consortiums) to tender commonly used goods or services together is encouraged in an effort to reduce costs by purchasing in larger volumes. The general principles of PUC's purchasing policy should be followed by any consortium that PUC participates with.

7.7 Vendor Credit Applications

The Purchasing Department will provide PUC's Credit Application -Standard form (See APPENDIX E) as required by new vendors. Purchasing Department will gather required information from prospective vendors on PUC's Vendor Activation Form (See APPENDIX F) and forward to Finance to be setup in the system.

7.8 Asset Disposal Procedure

The Manager of a department may declare goods as surplus or obsolete with the approval of the divisional VP. The Purchasing Department will determine if the goods can be used in other departments. If there is no corporate wide use for the goods, the Purchasing Department shall sell, exchange, donate or otherwise dispose of the goods according to guidelines established by the Purchasing Department. No employee who has responsibility for declaring goods surplus shall bid on or obtain any goods he or she has declared surplus.

7.9 Green Procurement Philosophy

PUC supports the purchase of environmentally preferred products. See APPENDIX G for PUC's green purchasing philosophy.

8.0 RELATED POLICIES

All purchases are subject to the signing authority policy and credit card policy as applicable.

9.0 DEFINITIONS

Bidders or Vendors: Contractor, wholesaler, distributor, service provider or any outside entity competing for corporate business. For the purpose of this policy these terms are used interchangeably and refer to the same entity.

Blanket Purchase Order: A contract between PUC and a vendor for the supply of repetitively ordered specified goods or services at a specified price but not specified quantity.

Controlled Products:
Under the Workplace Hazardous Materials Information System (WHMIS), a controlled product: Is any substance that is a compressed gas, or an oxidizing material. A substance that is

poisonous, infectious, flammable, combustible, corrosive or dangerously reactive. Meets the criteria in The Controlled Products Regulations.

Direct Purchase: Purchase not made with petty cash, credit card or purchase requisition. Invoice approval follows PUC's Signing Authority Policy.

Emergency: A situation where immediate action is required to avoid jeopardizing operations, disrupting service to the public, or threatening the health and safety of staff or the public.

Formal Competitive Bidding (Tenders, Request for Quotes or Proposals, Request for Prices): Procurement of goods/services, with bid opened in private and read at a predetermined time and place. The requisitioning party and at least one other person must be present at all tender openings along with the Purchasing Agent or designate. All submissions must be received as per the tender request package.

Hazardous Products:
Hazardous products are considered those that contain designated substances. This would be products that contain: Acrylonitrile; Arsenic; Asbestos; Benzene; Coke oven emissions; Ethylene oxide; Isocyanates; lead; mercury; silica; Vinyl chloride o. Reg. 490/09,s.2. Under the Hazardous Products Act

Non-competitive procurement: refers to an acquisition from a:

- Sole Source, or
- The item is an item of required design or is a proprietary or patented item, or
- There is a need for compatibility with goods and services previously acquired and there is no reasonable alternatives, or
- A reasonable attempt to identify competition has been unsuccessful.

O.E.M: is short for original equipment manufacturer. An original equipment manufacturer is a company that produces parts and equipment that may be marketed by another manufacturer.

Preferred vendor or contractor: A vendor or contractor that has a continuing arrangement to provide PUC with products or services. In addition, consideration of the following factors may apply: ability and experience to perform the work required; record of past performance with PUC; finance and technical resources; knowledge of PUC operations, systems and services; and compatibility with other goods and services of PUC.

Prequalification: A procurement process used to prequalify vendors for subsequent participation in an invitational Request for Proposal or Request for Quotation/Tender. Responses from proponents are evaluated against selection criteria set out in the solicitation, and a short list of pre-qualified proponents is created. Such could also be used for ongoing contract work of a lesser value.

Purchase Order: A legal document between PUC and a vendor to supply a specific quantity of goods or a specific set of services defined by such things as time period, location and price.

Purchase Requisition: A request to purchase, initiated by an employee, which defines the purchase specifications and requirements.

Sole Source: Recommended supply source where there is only one source of supply that meets the requirements.

Specification: A document package comprised of but not limited to technical provisions, safety rules, special provisions and other contract terms and conditions which must be satisfied by the contractor or supplier in performing the work. Specifications should be detailed but, where possible, not brand specific to allow for potential vendors to provide alternatives in the event an equal or better-proven product or method is available and shall not deter a competitive process.

Technical Provisions: The technical portion of the specification which relates to drawings, quality, design, standards, and description or by sample is the responsibility of the user department. Once established this information shall be retained in the appropriate filing system.

Tender: A formal request for sealed bids for the supply of goods or services in response to a formal solicitation process (advertised or not). For certainty, a Tender may include a Request for Proposal, a Request for Tender, a Request for Quotations, and any other document that is generally considered to facilitate the tendering process. Rules of the Tender are found in the request for Tender document and will govern the conduct of the various parties.

Terms and Conditions: Written provisions that determine the nature and scope of an agreement or contract and the responsibility and remedies of the parties to the agreement or contract.

Two Envelope Method: Bids are received in two separate envelopes. The first envelope contains technical and qualitative information and is opened and evaluated first. The second envelope contains price information and will be opened and evaluated after the information in the first envelope has been evaluated in accordance with the request for proposal documents.

Approved: ____________________ Date: Dec 28, 2018.

President & CEO

Revision History:

NOTE: A red line on the right side of document indicates a change		
Revision #	Date	Description

APPENDIX A

PURCHASING PROCESS

The requisitioner (being either our employee or an agent working on our behalf) is responsible for determining the need, specification, design or other technical data associated with a purchase as well as the following:

- All user departments are to provide the Purchasing Department with sufficient information to complete a transaction as noted. Failure to provide this information could result in a delay of turnaround time. Sufficient lead time must also be given to allow completion of the purchasing process and delivery.

- All purchases shall be in accordance with approved budgets.

- The necessary technical specifications and details as may be required to form a quotation and/or Tender Call must be forwarded to the Purchasing Department.

- The requisitioning department must assess the potential risk associated with contracted work and if necessary complete contractor prequalification.

- A purchase requisition may be generated by any employee but must be approved electronically by the appropriate signing authorities and include the proper account coding. Non- compliance to the above will result in the return of the purchase requisition to the source and ultimately loss of lead time.

Purchase requisitions are generated using the in-house requisitioning application (Cayenta) to initiate the purchasing process. The following are the steps in the purchasing process:

1. Description of the Need

The requestor must provide an accurate description of the materials or services required. For services, a Statement or Scope of Work must be prepared. General Terms and Conditions and technical recommendations should be provided for significant expenditures to support the need.

2. Determination and Analysis of Possible Sources of Supply

All potential vendors must be assessed to determine if they have the capability to provide the equipment, material, supplies or services.

Prequalification may be a requirement. This may include a risk assessment requirement as in the case of the PUC's Contractors Policy.

The Purchasing Department will attempt to ensure that any qualified person/company capable of supplying satisfactory goods and services has an equal opportunity to compete for the sale of products or services needed to support the requirements of PUC. Where prices are equal, determining factors may include conformity to specifications, record of deliveries and past performance of supplier's service and proximity of supply.

Some departments require cost estimates to determine whether or not to proceed with a project. Suppliers must be advised that these are study estimates only and any action on a purchase will go through the standard purchase process. Departments other than Purchasing may investigate pricing for their specialized technical needs when needed.

3. Determination of Terms and Conditions

All purchase requisitions must include general terms and conditions specific for the type of product and/or service required. The requisitions must include the proper authorizations and account coding.

The Purchase Requisition is forwarded to the Purchasing Department who will review the requisition for completeness.

When Purchasing processes a purchase requisition the following steps are taken:

- Check for alternative items, if required. The Purchasing Department will make every effort to investigate alternative items that might be acceptable to the requisitioner's requirements.
- If the materials or services are to go out for Tender, the Tender process must be followed.
- Participate in evaluating the quotations submitted by the requisitioner (if any), reviewing requisitioner's request, delivery requirements and cost, and obtain requisitioner's input as needed.
- Complete the purchase order.
- Confirm the order with the vendor and requisitioner and secure delivery.
- Arrange to have the goods or services delivered to the requisitioner or to the Stores Department.

4. Preparation and Placement of Purchase Order

The Purchasing Department will be responsible for the creation and issuing of all Purchase Orders. A blanket purchase order can be used for the supply of repetitively ordered specified goods or services at specified a price but not specified quantity. The term of a blanket order may be up to three (3) years, with allowable extensions provided the Value is maintained or a pricing structure is determined in advance and approved.

Proper authorization in accordance with PUC's Signing Authority Policy must be obtained in advance of purchases. Purchase Orders initiated after the provision of goods or services and/or receipt of supplier invoices are a serious violation of this policy and will require additional levels of authorization.

5. Follow-up on and/or Expediting Order

The Purchasing Department will be responsible for expediting all outstanding orders. The Purchasing Department will be responsible for invoicing discrepancies and will work in cooperation with Accounts Payable and the requisitioner to resolve such issues.

6. Receipts and Inspection of Goods

All materials purchased must be received and inspected to ensure that the requirements of the Purchase Order have been met. If material is nonconforming, it must be isolated prior to further processing.

All packing slips for material not received at PUC's main warehouse must be forwarded to the Stores Department in order to close the purchase order. This will allow for the timely processing of invoices for payment.

7. Clearance of the Invoice

All invoices will be paid by Accounting upon receipt of confirmation that the materials or services were received and acceptable and proper approvals are in place.

8. Change Order Request

A purchase order can only be changed if the requestor sends a new approved purchase request to the Purchasing Department requesting the change to the specific purchase order.

9. Records Management

All Purchasing records must be maintained by the Purchasing Department and/or the requesting employee/requester/originator as may be required. Documentation must be made available to the Purchasing Department as requested.

A copy of all approved Purchase Orders will be maintained on file in the corporate software.

For competitive processes, the Purchasing Department shall file, electronically or in hard copy, as appropriate, all documents associated with the procurement process and contract award (the solicitation document and any addendum and questions and answers; the supplier(s) proposal(s) and submission; the Purchase Orders; all contract related documents; and any other relevant supporting documentation), systematically for ease of reference and retrieval.

Proprietary and confidential information of suppliers will be safeguarded with appropriate care.

APPENDIX B

TENDERING PROCESS

1. Preparing a Tender Package

The Purchasing Department and the Requisitioner are both responsible for the preparation of the tender package:

The Requisitioner will:

- provide a complete statement of work and/or list of specifications which the item or service being purchased must meet;
- provide drawings, design details and schedules;
- detail the contract agreement and general conditions;
- detail supplementary conditions;
- detail a weighted scoring matrix to ensure awards are made to the bidder offering the best value;
- provide any addenda if necessary (prior to tender closing).

The Purchasing Department will:

- invite sealed Tenders by specific invitation and/or by public advertisement
- provide a standard Tender document on which the bidder will include the total price and other required information;
- provide a standard Tender covering letter establishing the date/time of Tender issuing and closing as well as place for receiving proposals;
- provide instruction to bidders detailing the how, when, where, and what form Tenders must be submitted;
- provide standard Terms of Conditions;
- send out the Tender package to bidders or post the Tender package electronically;

- obtain confirmation from the bidders as to their intent to participate;
- provide any addenda if necessary (prior to tender closing), and
- other relevant instructions as required.

2. General Rules to the Bidders

- No bids will be accepted after the Tender closing; late bids will be disqualified and returned, unopened, to the bidder.
- A new bid for the original unopened bid can be made, provided it is received before the bid closing date and time.
- Any inquiries made by the bidder must be directed electronically to the Purchasing Department or designate. The Purchasing Department along with the Requisitioner will respond. The inquiry and response will be formally issued to all bidders who have completed the confirmation of intent to participate.
- All other conditions of the Tender must be met.

3. Receipt of Tenders

All bids must be received at the location specified in the Tender document. Upon receipt of the Tender the receiver will date and time stamp and secure the Tenders.

- The minimum individuals attending the Tender opening meeting will be the Requisitioner, the Purchasing Agent and a third person;
- Bids will be opened and reviewed for acceptance;
- Any bid that does not satisfy the requirements may be disqualified, and duly noted
- A Bid Summary Sheet will be completed and circulated to the approving party
- A recommendation letter, with the bid summary sheet will be forwarded to the Requisitioner and Approver from Purchasing Agent indicating the Supplier/Contractor to be awarded the contract.

4. Award of Contract

The Purchasing Department or its designate will notify the successful vendor, in writing, of the intent to award of contract. If required, instructions about proceeding with the job will be detailed on the notification.

Unsuccessful bidders in a tender process can approach PUC to discuss where they can improve on their submissions and be debriefed on why they did not receive the award of contract. Details of the successful bid will remain confidential (price, etc.)

5. Preparation and Placement of Purchase Order

The Requestor will generate a purchase requisition and the Purchasing Department will prepare the contracts for signature. The Purchase Order will include the following information as appropriate:

- List the contract number
- a clear description of the product or services ordered;
- precise identification of type, class, and grade of the product; and
- any quality system standards which will apply.

Approved contracts are signed by the appropriate signing authority as per the signing authority policy, and then forwarded to the successful bidder for acceptance. The Requisitioning Department retains one copy of the contract and the original is filed in the Purchasing Department.

6. Guarantee of Contract Execution

- Where required tenders >$50,000 using the services of contractors shall be accompanied by a tender deposit in the form of a certified cheque or irrevocable letter of credit payable to PUC Services Inc. in the amount of Five Thousand Dollars ($5,000.00). Such deposit shall be security to PUC Services Inc. that the Bidder, if successful, will execute the contract documents within two (2) weeks of award and will start Work as specified. Failure to execute the documents within two (2) weeks or failure to start Work as specified will result in forfeiture of the tender deposit. Tender deposits of unsuccessful Bidders will be returned within three (3) weeks after award of the contract. The tender deposit of the successful Bidder will be returned with the first progress certificate.

- Suppliers may withdraw tenders/quotations prior to time of closing but not at any time thereafter. Bid deposits of any supplier withdrawing after time of closing shall be forfeited to PUC.

- Prior to the commencement of the work, the successful bidder may be required to provide security in the form of a performance bond to guarantee the performance of a contract, a labour and material payment bond to guarantee the payment of labour and materials supplied in connection with a contract or an irrevocable letter of credit.

- Other means to guarantee the execution of the contract may include surety bonds or other security deposits, progress payments and holdbacks.

- All contracts awarded for supply of labour and/or equipment must present proof of insurance at stipulated levels. Bid documents must clearly indicate the insurance requirements to be provided and maintained until the termination of the contract by the successful bidder, including a cross liability clause endorsement certifying PUC is named as an additional insured. The insurance coverage shall indemnify and save harmless PUC, their agents and employees from and against all claims, demands, losses, costs, damages, actions, suits, or proceedings by third parties that arise out of, or are attributable to, the contractor's performance of the contract.

- Prior to payment to a supplier, contracts awarded for supply of labour must present a Certificate of Clearance from the Workplace Safety and Insurance Board (WSIB) ensuring all premiums have been paid to the date of payment. It is the responsibility of the contractor to ensure that the Purchasing Department of PUC has, at all times, current copies of all required documents. Failure to do so may result in termination of contract. Clearance certificates must be refreshed every three months (for contracts with duration of three months or more).

- All contracts shall be governed by and construed in accordance with the laws of the Province of Ontario and the laws of Canada applicable therein.

7. Topic of Bid Irregularities

Extreme care shall be exercised to ensure that Irregular Bids are handled in a manner which is fair to other bidders as well as PUC Services operations.

Irregularities that may render a Bid reject-able will be disclosed in the Tender Document.

All open Bids will be reviewed for irregularities and if detected will be addressed at the discretion of the Evaluation Team with the Purchasing Agent. The Evaluation Team will use Guidelines set out by Purchasing to determine the appropriate response to the irregular bid.

APPENDIX C

PUC 500 Second Line East, P.O. Box 9000
Sault Ste. Marie, Ontario P6A 6P2

SOLE SOURCE APPROVAL FORM

Department

Requestor's NAME

Is this an Emergency or Critical to Operations ?

Vendor Name and info:

Instructions:
Your Purchase Requisition must have this completed and signed Form attached to it at time of sending PR for approval in System.
Quotation and/or other relevant documentation must be attached to this Form.
PR values less the $5,000.00 will need your manager and Purchasing Agent approval
PR values greater than $5,000.00 will need the above, and the approval of VP Finance & Corporate Support
PR values greater than $50,000.00 will need the above and the President/CEO's approval

Rationale / Justification information

Attachments

- ☐ quotation
- ☐ proposal
- ☐ other documentation

Budgetary Cost

Approval signatures

FIRST Level Approval

SECOND Level Approval

THIRD Level Approval

FOURTH Level Approval

APPENDIX D

EXPENDITURES EXCLUDED FROM THE APPLICATION OF THIS POLICY

The purchasing methods described in this policy do not apply to following goods and services:

- Training and education, courses, workshops, memberships, subscriptions, etc.
- Travel, meals, and accommodations
- Refundable employee expenses
- Medicals
- Damage claims
- Conservation and Demand Management, customer rebates or customer refunds
- Developer rebates and construction deposit refunds
- Wholesale electricity, transmission and connection invoices
- Electrical Safety Authority fees, rights-of-way, joint use agreement fees,
- Ontario Energy Board regulatory payments
- Payroll related payments , federal, provincial, municipal taxes and fees, vehicle license fees, and Payments in lieu of taxes (PIL's)
- Software license fees and annual maintenance fees (ongoing in nature after original award)
- Utility payments (hydro, cable, water, natural gas)
- Postage
- Debt retirement and Interest payments on debt
- Payments to Shareholders (including dividends)
- Charitable donations/Sponsorship
- Road reconstruction projects in conjunction with the City of Sault Ste. Marie

APPENDIX E

CREDIT APPLICATION INFORMATION

PUC SERVICES INC.

NATURE OF BUSINESS

Distribution of Electricity & Water

MAILING ADDRESS	SHIPPING ADDRESS
P.O. Box 9000, 500 Second Line East	500 Second Line East
Sault Ste. Marie, ON P6A 6P2	Sault Ste. Marie, ON P6B 4K1
(705) 759-6500	

TYPE OF BUSINESS	Revenue Canada - HARMONIZED SALES TAX NUMBER:
Corporation – Incorporated in 1917	R122198567

OWNERS / PRINCIPAL OFFICERS

Rob Brewer	Kelly McLellan
President / CEO	Vice President, Financial Services
500 Second Line East	500 Second Line East
Sault Ste. Marie, ON P6B 4K1	Sault Ste. Marie, ON P6B 4K1

ACCOUNTS PAYABLE		FINANCIAL INSTITUTION
CONTACT:	Accounts Payable Clerk	Royal Bank
PHONE #	(705) 759-6526	602 Queen Street East
EMAIL:	accounts.payable@ssmpuc.com	Sault Ste. Marie, ON

CURRENT TRADE SUPPLIERS

Guillevin Int.	Anixter Power Solutions	Wamco Waterworks Northern
81 White Oak Dr. E.	P.O. Box 399, Purdy Rd.	1771 Old Falconbridge Rd.
Sault Ste. Marie, ON P6B 4J7	Colborne, ON K0K 1S0	Sudbury, ON P3A 4R7
(705) 254-6461	(800) 263-7738	(705) 525-5000

ANNUAL REPORTS

Our financial reports can be found on our website, www.ssmpuc.com

ACKNOWLEDGEMENT

I hereby certify that the information contained herein is complete and accurate. This information has been furnished with the understanding that it is to be used to determine the amount and conditions of the credit to be extended. Furthermore, I hereby authorize the financial institutions listed to release necessary information of PUC Services Inc.

SIGNATURE OF AUTHORIZED OFFICAL

DHambly

SHELLEY HAMBLY
PURCHASING AGENT

APPENDIX F

500 Second Line East, P.O. Box 9000
Sault Ste. Marie, Ontario P6A 6P2

VENDOR ACTIVATION FORM

Date

Vendor Name

Business Number - O/A

Sales Contact Name

Accounts Receivable Name

Street Address

Remit to Address (if different)

City

Remit to City

Phone Number

Prov / State

Postal Code

Sales - Group e-mail address for P.O.'s

A/R Email Address

Provide a brief description of product/service your firm offers

Provide physical address of pick-up locations if different then above

Information Regarding Our Purchases

- Purchase orders are sent electronically via E-mail, and therefore a group e-mail account to send to is preferred to ensure it has been reviewed and a confirmation can be returned in a timely manner.
- IncoTerms are DDP, unless otherwise agreed to.
- Orders are paid net45 unless discount terms are offered.
- Orders are in CAD currency, unless otherwise stated.

Please provide all necessary Banking details below for us to process electronic payments to you.

Specify your discount terms

GST / HST No. (Revenue Canada)

Financial Institution Name

Bank No.

Transit No.

Account No.

E-mail Address for Payment Notification

Currency

W9 Income Form (IRS) (USA only)

Customs Brokerage Information (USA only)

If you are a CONTRACTOR or SERVICE PROVIDER the following must be completed

Check off the list below of items that are included with your submittal

- ☐ WSIB Clearance Certificate or Workers Insurance Certificate
- ☐ WSIB Incident Summary Report (NEER)
- ☐ General Liability Insurance - minimum of $2,000,000.00
- ☐ Current signed Health & Safety Policy
- ☐ Proof of completion of OHSA "Basic Awareness Training" - a letter is sufficient
- ☐ Signed Confidentiality Agreement
- ☐ Other: Trade Licenses or Certificates

SUPPLIER AUTHORIZATION

Authorized Signature

Date

Printed Name

Title

APPENDIX G

GREEN PURCHASING PHILOSOPHY

The Purchasing Department's policy at PUC Services is to support the purchase of recycled and environmentally preferred products in order to minimize environmental impacts relating to our work. We recognize our employees can make a difference in favor of environmental quality. We strongly recommend the purchase of environmentally preferable products whenever they perform satisfactorily and are available at a reasonably competitive price. We encourage waste prevention, recycling and the use of recycled/recyclable materials through contractual relationships and purchasing practices with vendors, contractors and businesses.

"Environmentally Preferable Products" means products that have a lesser impact on human health and the environment when compared with competing products. This comparison may consider raw materials acquisition, packaging, distribution, reuse, operation and/or disposal of the product.

"Recycled Products" are products manufactured with waste material that has been recovered or diverted from the waste stream. Recycled material may be derived from post-consumer waste (material that has served its intended end-use and been discarded by a final consumer), industrial scrap, manufacturing waste and/or other waste that otherwise would not have been utilized.

Purchasing solicits the use of recycled and other environmentally preferred products (e.g. paper Products, including janitorial supplies, shop towels, hand towels, facial tissue, toilet paper etc.) in its procurement documents as appropriate. We also structure applicable contracts to offer and/or feature recycled-content products whenever possible, (e.g., office supplies and janitorial supplies).

The Purchasing Dept. supports PUC Services Environmental Policy and its commitment to making environmental protection an integral part of our planning, operating and purchasing decisions. We accomplish this by supporting the purchase of recycled and environmentally preferred products in order to minimize environmental impacts relating to our work.

APPENDIX D

IndEco PUC LRAMVA

(2018-2022)

Strategic Solutions for a Changing World™

PUC Distribution Inc.
2018-2022 LRAMVA

PUC Distribution Inc.

Lost revenue related to Conservation and Demand Management

2018-2022

IndEco

This document was prepared for PUC Distribution Inc. by IndEco Strategic Consulting Inc.

For additional information about this document, please contact:

IndEco Strategic Consulting Inc.
300 -192 Spadina Avenue
Toronto, ON, Canada
M5T 2C2

Tel: 888 463-3261
E-mail: **info@indeco.com**

IndEco report C2198

12 July 2022

Table of Contents

Introduction

The Lost Revenue Adjustment Mechanism (LRAM) was developed to remove a disincentive electricity local distribution companies (LDCs) may have to promote conservation and demand management (CDM) programs. CDM programs are designed to provide energy savings and peak demand reductions for the customers of the LDC. These savings and reductions directly impact the LDC's revenue. The LRAM allows LDCs to be compensated for lost revenue that resulted from CDM programs the LDC offered to its customers.

Starting in 2011, the Ontario Energy Board (OEB) authorized LDCs to establish an LRAM variance account (LRAMVA) to capture the impact of CDM programs on the revenue of LDCs. The variance in the LRAMVA is between the lost revenue due to independently verified load impacts of CDM and the lost revenue from any CDM impacts on the LDC included in the LDC's load forecast.[1]

PUC Distribution Inc. contracted with the Ontario Power Authority (OPA, which has now been merged into the Independent Electricity System Operator – IESO) to offer a suite of CDM programs to customers for the 2011-2014 period and subsequently with the IESO for the 2015-2019 period.

PUC's lost revenues from CDM have already been claimed for results through 2017. Lost revenue variances being claimed in the 2023 rate application are summarized on Figure 1.

[1] *Guidelines for Electricity Distributor Conservation and Demand Management*. Ontario Energy Board. April 26, 2012 (EB-2012-0003).

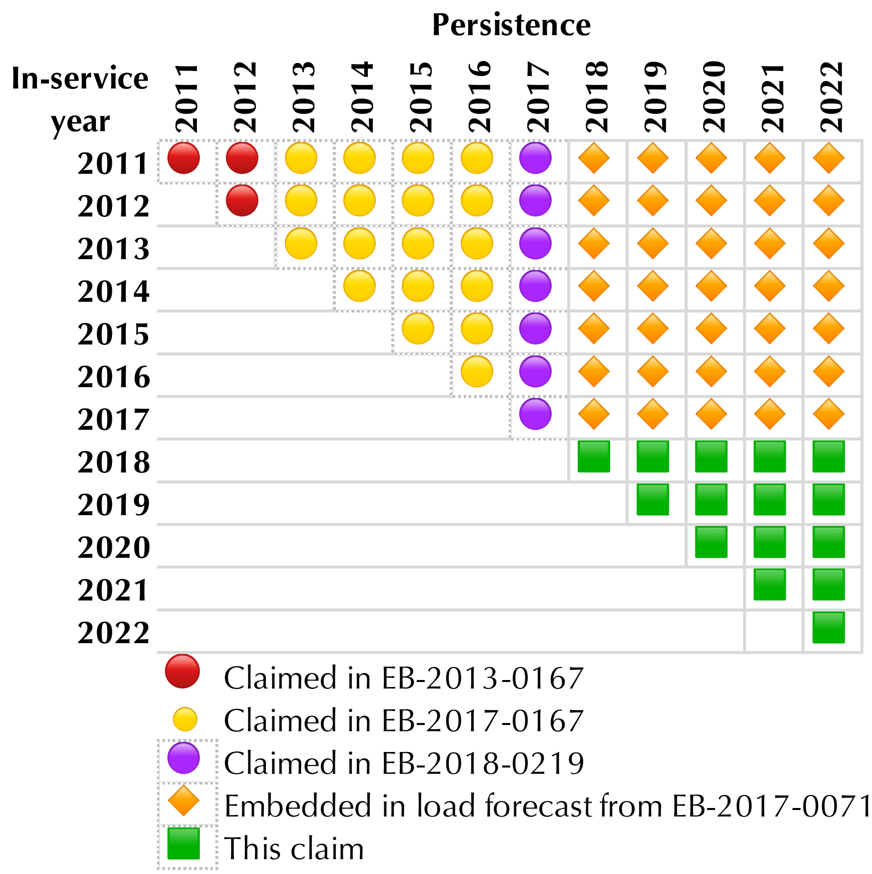


Figure 1 LRAMVA claims for PUC Distribution Inc.

PUC is requesting disposition of the LRAMVA balance that will remain at the end of 2022, including specifically:

- Savings in 2018 and 2019 of projects approved before April 1, 2019 as part of the Conservation First Framework, but completed in 2018 or later
- Persistence of those savings through 2022
- Persistence in 2018-2022 of savings from programs offered in 2017.

PUC is making this claim as part of a cost of service rate application for the 2023 rate year. That application will include a new load forecast that will capture any savings from the Conservation First Framework or the earlier framework that persist beyond 2022. Given that PUC is no longer offering customers new CDM programs, the LRAMVA balances that will remain through December 31, 2022 from PUC's initiatives under the Conservation First Framework (CFF) can be determined at this time.

In preparing this claim, the methodology prescribed by the OEB filing requirements has been followed:

"The OEB will rely on the Participation and Cost Reports and detailed project level savings files as supporting documentation when assessing applications for

lost revenues in relation to energy and demand savings from programs delivered under the CFF where final verified results from the IESO are not available."[2]

[2] Ontario Energy Board, 2021. *Filing Requirements for Electricity Distribution Rate Applications - 2021 Edition for 2022 Rate Applications*. Chapter 2 Cost of Service

Methodology

In principle, the determination of lost revenues is a simple calculation:

LR = (CDM results – CDM results in the load forecast) * rate

In practice, it is somewhat more complicated than that because of the limitations of the information available to calculate CDM results, the use of different volumetric units for billing in different customer classes and the need to determine carrying charges on the lost revenues.

The information sources for the LRAMVA analysis are summarized on Table 1.

Table 1 Information sources for LRAMVA analysis

CDM program years	Sources	Information used in this analysis	Used for
2017	2017 final verified results reports for PUC (IESO)	Net first year energy savings by program	Savings
		Net first year demand reductions by program	Savings
		Persistence of results through 2022 by program	Savings
	2017 final verified results by project (IESO)	Net first year energy savings by project	Allocation to rate classes
		Net first year demand reductions by project	Allocation to rate classes
2018 - March 2019	April 2019 Participation & Cost Report for PUC (IESO)	Unverified first year net savings for 2018, Jan-Apr 2019, and adjustments for 2017 by program	Savings
		Unverified persistence in 2020 by program	Savings in 2020
	CDM databases (PUC)	Reported gross energy and demand savings	Calculating net savings
	2017 final verified results reports for PUC (IESO)	Net-to-Gross and Realization Rates	Calculating net demand savings in the P&C reports
		Rate of loss of persistence	Persistence in 2020-2028
2018-2022	CDM databases (PUC)	Reported gross first year energy savings by project	Gross savings and allocation by program
		Reported gross first year demand savings by project	Gross savings and allocation by program
	2017 final verified results reports for PUC (IESO)	Net-to-Gross and Realization Rates	Calculating net energy and demand savings by program
		Rate of loss of persistence	Persistence through 2022 where IESO persistence is not available.

CDM RESULTS

For programs offered in 2017, the IESO performed evaluations which examined reported gross energy savings from the programs, and the Realization Rate (RR) and the net-to-gross ratio (NTGR), and then from those calculated net energy savings for each initiative or program. Peak load reductions were also calculated and reported in the same way. For some programs the IESO calculated gross and net energy at the project level.

Provincial results were allocated to individual LDCs based on each LDC's individual performance where possible, or through an allocation process.

The IESO provided the persistence into future years of savings and reductions for each program.

Before final evaluation results were available, the IESO published monthly Participation and Cost (P&C) reports that showed both verified and preliminary unverified savings. With the ending of the Conservation First Framework by the Ontario government on April 1, 2019, the IESO stopped producing reports of verified results. Unverified net energy savings for 2018, Q1 2019 and adjustments to program results for 2017 that came in after the 2017 final verified results report are in the April 2019 Participation and Cost reports. Results after the April 2019 Participation and Cost reports are from PUC databases which record gross values, as reported to the IESO.

These are the best and most definitive and defensible estimates of savings associated with these programs and incorporate the most appropriate estimates of results from the measures installed.

However, these data have some limitations, and require some adjustments for use in lost revenue calculations.

Determining net demand savings for projects completed after the 2017 final results

Only reported gross demand savings are available for projects completed after the 2017 final results report. That includes both projects captured in the P&C report, and post-P&C projects captured in PUC CDM databases. These reported values were converted to net values using the net-to-gross values and realization rates in the 2017 final verified results report.

Allocating results to customer classes

The IESO reports results by program or initiative. These only partially map onto customer classes. The IESO provided net results by project for projects in programs that span multiple customer classes in 2017 and PUC identified the customer classes for these projects to calculate the allocation across customer classes. For 2018 through 2021, PUC reported information on projects to the IESO and again the customer classes were identified for individual projects to calculate the allocation. The allocation was calculated according to the billing unit of the relevant customer class. That is, for GS<50 projects, the allocation to GS<50 is the percentage of total kWh for projects in that customer class; for

GS>50, their allocation is the percentage of total kW for projects in that customer class.

In most cases, the allocation is straightforward. Savings in the Retrofit Program and the Audit Funding Program spanned more than one customer class in any given year. For these, allocations were done using the process described in Figure 2.

Figure 2 Allocation of savings to customer classes

Customer classes were identified for all projects in the program, the percentage of total energy use in each customer class billed by kWh was calculated, and the percentage of total demand reductions in each customer class billed by kW was calculated.

PUC bills customers in different customer classes using different volumetric units, either kilowatt hours (kWh), or customer peak monthly kilowatts (kW). The customer classes (and billing units) for PUC are:

- Residential (kWh)
- GS <50 kW (kWh)
- GS 50 – 4,999 kW (kW)
- Unmetered Scattered Load (kWh)
- Sentinel Lighting (kW)
- Street Lighting (kW).

Tables 5-c through 5-e of the OEB LRAMVA work form show the percentage allocation by customer class for 2017 through 2019 results respectively. (PUC did not identify any projects completed after 2019.) In each year the customer class allocation percentage totals for each program may not add up to exactly 100% in cases where kWh savings are allocated to customer classes billed by kWh and kW demand reductions are allocated to customer classes billed by kW. The details of the allocation calculation are on Tab 3-a of the work form.

Application of reported results

The IESO reported both energy savings and reductions in demand. Depending on the customer class, distribution revenue is based on either kilowatt-hours used, or the customer's monthly peak kilowatt use. For customer classes where the customer is charged for distribution by energy use (kWh), the IESO reported net energy savings are used to calculate lost revenues related to CDM results. For customer classes where the LDC charges for distribution are based on the customer's peak monthly demand (kW), the IESO reported net peak demand reductions are used to calculate lost revenues related to CDM results. The demand reductions in the IESO reports are multiplied by the number of months a specific program impacts a customer's peak demand. "The IESO indicated that the demand savings from energy efficiency programs shown in the Final CDM Results should generally be multiplied by twelve (12) months to represent the demand savings the distributor has experienced over the entire year."[3]

No lost revenues are claimed for demand response programs, consistent with OEB policy.[4]

For 2018 and 2019 and adjustments to 2017 made after the 2017 final results were available, the IESO did not report demand reductions. Demand reductions were estimated based on the reported post-completion gross demand savings by project and the 2017 NTG and RR factors.

Persistence

Persistence of 2017 to 2019 results through 2022 is shown at the bottom of Table 5-c to Table 5-e of the workform.

Persistence of programs in 2015 to 2017 is included in the 2017 final verified results report.

The April 2019 Participation and Cost report provided estimated net energy persistence in 2020 for all verified and unverified results.

Where persistence data were not provided, persistence is estimated using the following methods:

- For unverified program results in 2017 to 2019 in the April 2019 Participation and Cost Report, the annual persistence of the unverified results to 2020 was estimated using linear interpolation between the program year and 2020
- For unverified results, persistence in 2021 to 2022 was estimated using the same rate of persistence seen in 2017 for the verified results for 2017.

Load reductions accounted for in the load forecast

In recent years, LDCs have tried to account for load losses due to CDM programs in their load forecasts, submitted as part of their Cost of Service

---

[3] Ontario Energy Board, *Updated Policy for the Lost Revenue Adjustment Mechanism Calculation: Lost Revenues and Peak Demand Savings from Conservation and Demand Management Programs*, EB-2016-0182, May 19, 2016, p. 4.

[4] Ibid. p. 7.

applications. These forecasted reductions need to be deducted from load losses attributable to CDM programs to determine the final impact of CDM on revenues. That is, the impact is the *variance* between the results accounted for in the load forecast and the results attributable to the programs. In PUC, the last load forecast was for 2018, and a threshold for 2018 and later was determined.

Overall impact of CDM on load, by customer class

The overall impact of CDM energy savings and demand reductions on load is calculated from the IESO energy savings and peak demand reductions, allocated by customer class. Finally, the difference is calculated between the overall estimated impact on loads and the load reductions attributable to CDM that were captured in the most recent load forecast.

Overall lost revenues in 2018-2022 are shown on Table 5-d to 5-h of the workform.

DISTRIBUTION RATES

Revenue impacts to the LDC associated with CDM are calculated using the distribution volumetric rate. Most other rate components (e.g. service charges, global adjustment, transmission charges) are either fixed charges or pass-throughs for the utility that do not affect the LDC's revenues when energy efficiency measures are adopted by customers. An exception is for certain rate riders related to taxes or where rate implementation was delayed, and these are added to the distribution volumetric rates for lost revenue calculations, where applicable.

CARRYING CHARGES

Because these revenues are lost throughout the year and are only recovered through rate riders in subsequent years, the Ontario Energy Board has permitted the LDCs to claim carrying charges on these lost revenues at a rate prescribed by the OEB and published on the Board's website. The carrying charges are simple interest, not compounded, and are calculated on the monthly lost revenue balance. Because the IESO final results estimates are reported annually, and monthly estimates are not available, the incremental results are assumed to be equally distributed across the months. So, 1/12 of the annual results are allocated to each month of the year.

Carrying charges for results realized in 2018 to 2022 accrue from the time of the results. Carrying charges on persistent savings from earlier projects accrue from January 1, 2018. Carrying charges on savings through December 31, 2017 have already been claimed.

Results

Following the methodology described above, lost revenues were calculated for PUC. The discussion of results refers to tables provided in the completed LRAMVA work form. The work form uses the OEB's template.

LOST REVENUES

The lost revenues for each year by customer class for PUC calculated from final CDM program results are shown on Table 1-b of the OEB LRAMVA work form. The lost revenue for 2018 through 2022 is based on the load impact for each customer class multiplied by the rate for that customer class in that year. The load impact includes only the impact of CDM programs offered through the Conservation First Framework.

Table 1-b of the OEB LRAMVA work form also shows the anticipated lost revenue in each year due to CDM activities accounted for in PUC's 2018 Cost of Service application. The impact on PUC's revenue is the variance between what is calculated from final CDM program results and estimated CDM activities.

CARRYING CHARGES

The monthly carrying charges by customer class on PUC's lost revenue variance are shown on Table 6 of the OEB LRAMVA work form. The carrying charges are reported monthly, from the time the lost revenues accrue.

TOTAL LRAMVA CLAIM

The LRAMVA balance on December 31, 2022 for PUC that includes persistence of results from 2017-2022 CDM programs is $194,519. The total carrying charges on this LRAMVA balance accumulated to December 31, 2022 are $6,941. The balances by rate zone and individual customer class are shown on Table 2.

There are only savings to claim in the residential and general service customer classes. Savings in none of the customer classes will increase over time, and there is thus no reason to delay a claim because of the zero amounts in other customer classes.

PUC plans to recover the LRAMVA balance over one year.

Table 2 Summary of LRAMVA claim by customer class and rate zone

Customer class	Principal	Carrying charges	Total LRAMVA claim
Residential	$42,005	$2,502	$44,507
GS<50 kW	-$103,740	-$3,211	-$106,950
GS 50-4,999 kW	$256,254	$7,650	$263,903
Total	**$194,519**	**$6,941**	**$201,460**

Note: there is no LRAMVA claim for customer classes not shown.

EXHIBIT 5

COST OF CAPITAL AND
CAPITAL STRUCTURE

TABLE OF CONTENTS

LIST OF TABLES

EXHIBIT 5: COST OF CAPITAL AND CAPITAL STRUCTURE

The purpose of this evidence is to summarize the method and cost of financing capital requirements for the 2023 Test Year.

5.1 CAPITAL STRUCTURE

PUC Distribution Inc. ("PUC") has a current deemed capital structure of 56.00% long term debt with a debt rate of 4.12%, 4.00% short term debt with a debt rate of 2.29% and 40.00% equity with a return of 9.00% as approved in the 2018 cost of service ("COS") rate decision (EB-2017-0071).

PUC has prepared this 2023 COS Application in accordance with the guidelines provided in the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities* issued by the Ontario Energy Board (the "Board") on December 11, 2009. For the purposes of preparing this Application, PUC has used the cost of capital parameters issued by the Board on October 28, 2021 for 2022 cost of service rate applications.

5.2 COST OF CAPITAL (RETURN ON EQUITY AND COST OF DEBT)

For the purposes of preparing this application, PUC has used the cost of capital parameters issued by the Board on October 28, 2021 for 2022 COS rate applications which reflects a return on equity of 8.66%. During this proceeding, PUC expects that the Board will update the cost of capital parameters for 2023 COS rate filings which PUC intends to incorporate into this application.

5.2.1 Cost of Debt: Short Term

For the purposes of preparing this application, PUC has used the cost of capital parameters issued by the Board on October 28, 2021 for 2022 COS rate applications which reflects a deemed short term debt rate of 1.17%. During this proceeding, PUC expects that the Board will update the cost of capital parameters for 2023 COS rate filings which PUC intends to incorporate into this application.

5.2.2 Cost of Debt: Long Term

PUC is requesting a return on long term debt rate for the 2023 Test Year of 3.97%. This rate represents the weighted average cost of long-term debt for the following long term debt instruments:

- Promissory note payable to parent company, PUC Inc., for $26,534,040 with interest payable quarterly, rates periodically negotiated, and principal payable one year after demand. In this application, the interest rate on this note will be based on the Board's cost of capital parameter for long term debt for 2023 cost of service rate applications issued October 28, 2021 which is 3.49%. This promissory note is attached as Appendix A.

- PUC has 7 loans payable to Ontario Infrastructure and Lands Corporation ("OILC"):
    - Loan payable number 1 to OILC is an amount of $5,000,000. It is a 15-year debenture with a fixed interest rate of 3.82%. The loan is payable semi-annually for principal and interest. Security is in the form of a second ranking general security agreement. This was used to finance PUC's smart meter project.

- Loan payable number 2 to OILC was used for the construction of the new integrated service center/office building. The total amount of the approved loan principal is $21,180,000. The loan is payable over 25 years with interest payable monthly at a fixed interest rate and principal, secured by a mortgage on the land and building and a general security agreement. The fixed interest rate on this loan is 4.57%.

- Loan payable number 3 to OILC is an amount of $15,000,000. It is a 25-year debenture with a fixed interest rate of 3.47%. Security is in the form of a fourth ranking general security agreement and a guarantee and assignment of shares from the company's shareholder, PUC Inc. The proceeds of this loan were used for distribution infrastructure replacement.

- Loan payable number 4, 5 and 6 are part of a $30,000,000 drawdown credit facility with OILC. Table 5-1 represents the drawdowns taken with applicable interest rates.

Table 5-1: Loan Breakdown

Date	Amount	Interest Rate	Term
May 1, 2020	$5,800,000	2.11%	15 years
February 16, 2021	$4,000,000	3.65%	20 years
January 1, 2023	$20,200,000	5.00%	20 years

Loan number 4 was a drawdown of $5,800,000 on the $30,000,000 credit facility. The approximate amount of principal outstanding as of January 1, 2023 is $5,156,998. It is a 15-year debenture with a fixed interest rate of 2.11%. Security is in the form of a fourth ranking general security agreement and a guarantee and assignment of shares from the company's shareholder, PUC Inc. The proceeds of this loan were used for distribution infrastructure replacement.

Loan number 5 was a drawdown of $4,000,000 on the $30,000,000 credit facility. The approximate amount of principal outstanding as of January 1, 2023 is $3,885,023. It is a 20-year debenture with a fixed interest rate of 3.65%. Security is in the form of a fourth ranking general security agreement and a guarantee and assignment of shares from the company's shareholder, PUC Inc. The proceeds of this loan were used for distribution infrastructure replacement.

Loan number 6 is an estimated drawdown of $20,200,000 on the $30,000,000 credit facility. Loan payable number 6 is to be finalized with OILC. It is anticipated to be a 20-year debenture with an estimated fixed interest rate of 5.00% used for rate making purposes. Security is in the form of a fourth ranking general security agreement and a guarantee and assignment of shares from the company's shareholder, PUC Inc. The proceeds of this loan were used for Sault Smart Grid ("SSG") Financing.

5.2.3 Capital Structure and Cost of Capital

Below is a reproduction of Appendix 2-OA that demonstrates the elements of the capital structure and cost of capital from 2018 Board-approved and 2023 Test Year. For 2023, the weighted average cost of capital of 5.73% will be applied to the rate base of $136,089,187, which is explained in detail in Exhibit 2, to determine a return on rate base of $7,803,354 that is included in the proposed revenue requirement.

Table 5-2: Appendix 2-OA Capital Structure and Cost of Capital

Appendix 2-OA
Capital Structure and Cost of Capital

This table must be completed for the last OEB-approved year and the test year.

Test Year: 2023

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$76,209,945	3.97%	$3,025,535
2	Short-term Debt	4.00%	(1)	$5,443,567	1.17%	$63,690
3	**Total Debt**	60.0%		$81,653,512	3.78%	$3,089,225
	Equity					
4	Common Equity	40.00%		$54,435,675	8.66%	$4,714,129
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$54,435,675	8.66%	$4,714,129
7	**Total**	100.0%		$136,089,187	5.73%	$7,803,354

Last OEB-approved year: 2018

Line No.	Particulars	Capitalization Ratio (%)		Capitalization Ratio ($)	Cost Rate (%)	Return ($)
	Debt					
1	Long-term Debt	56.00%		$55,808,511	4.12%	$2,299,311
2	Short-term Debt	4.00%	(1)	$3,986,322	2.29%	$91,287
3	**Total Debt**	60.0%		$59,794,833	4.00%	$2,390,597
	Equity					
4	Common Equity	40.00%		$39,863,222	9.00%	$3,587,690
5	Preferred Shares			$ -		$ -
6	**Total Equity**	40.0%		$39,863,222	9.00%	$3,587,690
7	**Total**	100.0%		$99,658,055	6.00%	$5,978,287

5.2.4 Weighted Average Cost of Long-Term Debt

Outlined below is a reproduction of Appendix 2-OB listing PUC's long term debt instruments and weighted average cost of long-term debt from 2018 to the 2023 Test year.

Table 5-3: Appendix2-OB Debt Instruments

Appendix 2-OB
Debt Instruments

Notes

1 If financing is in place only part of the year, separately calculate the pro-rated interest in the year and input in the cell.
2 Input actual or deemed long-term debt rate in accordance with the guidelines in *The Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, issued
3 Add more lines above row 12 if necessary.

Year 2018

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	23-Jun-05	No Term	$ 26,534,040	4.16%	$1,103,816.06
2	Loan - Smart Meter Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jul-13	15	$ 3,785,143	3.82%	$ 144,592.46
3	Loan - PUC Admin Building	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	25	$ 19,096,479	4.57%	$ 872,709.09
4	Loan	Infrastructure Ontario	Third-Party	Fixed Rate	16-Jun-16	25	$ 14,386,106	3.47%	$ 499,197.88
Total							$ 63,801,768	4.11%	$2,620,315.50

Year 2019

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	23-Jun-05	No Term	$ 26,534,040	4.16%	$1,103,816.06
2	Loan - Smart Meter Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jul-13	15	$ 3,485,912	3.82%	$ 133,161.84
3	Loan - PUC Admin Building	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	25	$ 18,534,697	4.57%	$ 847,035.65
4	Loan	Infrastructure Ontario	Third-Party	Fixed Rate	16-Jun-16	25	$ 13,980,667	3.47%	$ 485,129.14
Total							$ 62,535,316	4.11%	$2,569,142.70

Year 2020

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	23-Jun-05	No Term	$ 26,534,040	4.16%	$1,103,816.06
2	Loan - Smart Meter Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jul-13	15	$ 3,175,141	3.82%	$ 121,290.39
3	Loan - PUC Admin Building	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	25	$ 17,946,697	4.57%	$ 820,164.05
4	Loan	Infrastructure Ontario	Third-Party	Fixed Rate	16-Jun-16	25	$ 13,560,934	3.47%	$ 470,564.41
Total							$ 61,216,812	4.11%	$2,515,834.91

Year 2021

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	23-Jun-05	No Term	$ 26,534,040	4.16%	$1,103,816.06
2	Loan - Smart Meter Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jul-13	15	$ 2,852,386	3.82%	$ 108,961.15
3	Loan - PUC Admin Building	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	25	$ 17,331,255	4.57%	$ 792,038.35
4	Loan	Infrastructure Ontario	Third-Party	Fixed Rate	16-Jun-16	25	$ 13,126,401	3.47%	$ 455,486.11
5	Loan $5.8MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	15-Feb-21	15	$ 5,800,000	2.11%	$ 122,380.00
11									$ -
12									$ -
Total							$ 65,644,082	3.93%	$2,582,681.68

Year 2022

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	23-Jun-05	No Term	$ 26,534,040	4.16%	$1,103,816.06
2	Loan - Smart Meter Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jul-13	15	$ 2,517,183	3.82%	$ 96,156.40
3	Loan - PUC Admin Building	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	25	$ 16,687,091	4.57%	$ 762,600.06
4	Loan	Infrastructure Ontario	Third-Party	Fixed Rate	16-Jun-16	25	$ 12,767,549	3.47%	$ 443,033.95
5	Loan $5.8MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	15-Feb-21	15	$ 5,467,763	2.11%	$ 115,369.80
6	Loan $4.0MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	1-Mar-22	15	$ 4,000,000	3.65%	$ 146,000.00
7									$ -
Total							$ 67,973,626	3.92%	$2,666,976.28

Year 2023

Row	Description	Lender	Affiliated or Third-Party Debt?	Fixed or Variable-Rate?	Start Date	Term (years)	Principal ($)	Rate (%) [2]	Interest ($) [1]
1	Promissory Note	PUC Inc.	Affiliated	Fixed Rate	23-Jun-05	No Term	$ 26,534,040	3.49%	$ 926,038.00
2	Loan - Smart Meter Loan	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jul-13	15	$ 2,344,765	3.82%	$ 89,570.03
3	Loan - PUC Admin Building	Infrastructure Ontario	Third-Party	Fixed Rate	1-Oct-13	25	$ 16,012,864	4.57%	$ 731,787.88
4	Loan	Infrastructure Ontario	Third-Party	Fixed Rate	16-Jun-16	25	$ 12,210,836	3.47%	$ 423,716.02
5	Loan $5.8MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	15-Jan-21	15	$ 5,156,998	2.11%	$ 108,812.66
6	Loan $4.0MM drawdown	Infrastructure Ontario	Third-Party	Fixed Rate	1-Mar-22	15	$ 3,885,023	3.65%	$ 141,803.33
7	Loan - SSG financing	Infrastructure Ontario	Third-Party	Fixed Rate	1-Jan-23	20	$ 20,200,000	5.00%	$1,010,000.00
Total							$ 86,344,526	3.97%	$3,431,727.92

5.2.5 Profit or Loss on Redemption of Debt or Preferred Shares

There is no profit or loss on redemption of debt or preferred shares.

5.2.6 Historical Return on Equity

PUC's historical return on equity ("ROE") is presented in table 5-4 below. Once PUC rebased as part of its 2018 application, it was able to achieve ROE levels closer to the approved ROE from its 2018 application.

Table 5-4 Historical Return on Equity

Performance Year	Profitability: Regulatory Return on Equity - Deemed	Profitability: Regulatory Return on Equity - Achieved
2021	9.00%	7.60%
2020	9.00%	8.75%
2019	9.00%	8.87%
2018	9.00%	4.25%

5.2.7 Notional Debt

Notional debt is that portion of the deemed debt capitalization that results from differences between the distributor's actual debt and the deemed debt of 60% (56% long-term debt and 4% short-term debt). PUC has approximately $4.69 million in notional debt in the Test year (i.e., deemed debt portion of rate base of $81.65 million minus actual debt of $86.34 million).

5.3 NOT-FOR-PROFIT CORPORATIONS

PUC is a for-profit corporation. As a result, the filing requirements associated with not-for-profit corporations are not applicable.

APPENDIX A

Promissory Note Between PUC Distribution Inc. and PUC Inc.

PROMISSORY NOTE

ISSUED TO: PUC INC. (the "Holder")

ISSUED BY: PUC DISTRIBUTION INC (the "Borrower")

AMOUNT: $30,290,000.00 (the "Principal")

1.0 PROMISE TO PAY

1.1 In consideration of the redemption by the Borrower of 3,029 Special Shares, the Borrower hereby promises to pay to the Holder at 765 Queen Street East, Sault Ste. Marie, Ontario the Principal in lawful money of Canada in the manner hereinafter provided, together with interest and other moneys which may from time to time be owing hereunder or pursuant hereto.

2.0 PRINCIPAL PAYMENTS

2.1 On demand the issuer shall pay to the Holder the balance of Principal, interest and all other monies which may be owing hereunder.

3.0 INTEREST

3.1 This note shall bear interest at the rate of 10% per annum calculated from December 1st, 2001 The first interest payment shall be due on the 31st day of December 2001 and thereafter interest shall be payable quarterly on the last day of March, June, September and December. Notwithstanding the foregoing, the interest rate may be adjusted on a quarterly basis by mutual agreement between the Borrower and the Holder. The Borrower agrees that in the absence of manifest error, the record kept by the Holder on this Note of such changes in the interest rate shall be conclusive evidence of the matters recorded

3.2 Interest shall also be calculated and payable on overdue interest from time to time outstanding at the rate in effect at the date of default.

4.0 DEFAULT

4.1 In the event of default, the full unpaid balance of the Principal and all accrued and unpaid interest thereon shall at the option of the Holder forthwith become due and payable.

5.0 PREPAYMENTS

5.1 The Borrower may, at any time, prepay the outstanding aggregate Principal amount of this Note whether in whole or in part without notice, bonus or penalty.

6.0 WAIVER

6.1 Presentment for payment, demand, protest, notice of protest and notice of dishonour of this Note are hereby waived.

7.0 SUCCESSORS AND ASSIGNS

7.1 The Holder shall not assign any interest in this Note without the prior written consent of the Borrower, which consent shall not be unreasonably withheld or delayed. This Note shall be binding upon the Borrower and its successors and assigns and shall enure to the benefit of the Holder and successors and permitted assigns.

8.0 GOVERNING LAW

8.1 The Note shall be governed and construed in accordance with the laws of the Province of Ontario and the federal laws of Canada applicable therein.

9.0 COLLECTION COSTS

9.1 To the extent permitted by applicable law, the Borrower agrees to pay all costs of collection including, without limitation, reasonable solicitor's fees, disbursements and expenses on a solicitor and his own client basis incurred by the Holder in connection with the enforcement of this Note.

10.0 TIME OF ESSENCE

10.1 Time is of the essence.

11.0 INTERPRETATION

11.1 The division of this Note into sections and insertion of the headings in this Note are for convenience of reference only and shall not affect the construction or interpretation of this Note.

IN WITNESS whereof the Borrower has executed this Note as of the 1st day of December, 2001.

PUC DISTRIBUTION INC.

Per: B. Curran

Brian Curran, President

Clyde E. Healey

Per:

Clyde Healey, Secretary

We have authority to bind the Corporation

DATE	INTEREST RATE	NOTATION MADE BY

THIS AGREEMENT made the 18th day of December, 2008.

BETWEEN:

PUC INC.,
a Ontario Corporation,

(hereinafter referred to as the "Holder")

- and –

PUC DISTRIBUTION INC., an Ontario Corporation,

(hereinafter referred to as the "Borrower")

THIS AGREEMENT WITNESSES that in consideration of the mutual covenants and conditions contained herein and other good and valuable consideration the parties hereto agree as follows:

1.0 BACKGROUND

1.1 The Borrower is indebted to the Holder in the amount of Eleven Million Six Hundred and Fifty Thousand Dollars ($11,650,000.00) as evidenced by a promissory note dated August 15th, 2001 ("Promissory Note Number 1");

1.2 The Borrower is further indebted to the Holder in the amount of Thirty Million Two Hundred and Ninety Thousand Dollars ($30,290,000.00) as evidenced by a promissory note dated December 1st, 2001 ("Promissory Note Number 2");

1.3 As a result of legislative changes imposing debt/equity limits on Municipal Electric Utilities in Ontario the parties hereto have agreed to amend Promissory Note Number 1 and Promissory Note Number 2 as provided herein.

2.0 CONVERSION OPTION – PROMISSORY NOTE NUMBER 1

2.1 Promissory Note Number 1 is hereby amended by adding to paragraph 1.0 the following:

> 1.2 The Holder shall, at any time during the currency of this Note, have the option to convert all or any part of the principal of the Note into Common Shares of the Borrower at the rate of $2,330.00 per share. This option shall be exercised by the Holder by written notice delivered or sent by registered mail to the Holder at the Holder's principal place of business specifying the amount of principal to be converted and the effective date of the conversion, which date shall not be less than 10 days from the date of the Notice. The Holder shall, on the effective date specified in the Notice, issue to the Holder as fully paid and non-assessable such number of Common Shares as may be required to convert the amount of principal specified in the notice at the rate aforesaid and upon the issuance of such Shares the principal amount of the Note shall be reduced accordingly.

3.0 CONVERSION OPTION – PROMISSORY NOTE NUMBER 2

3.1 Promissory Note Number 2 is hereby amended by adding to paragraph 1.0 the following:

> 1.2 The Holder shall, at any time during the currency of this Note, have the option to convert all or any part of the principal of the Note into Common Shares of the Borrower at the rate of $2,330.00 per share. This option shall be exercised by the Holder by written notice delivered or sent by registered mail to the Borrower at the Borrower's principal place of business specifying the amount of principal to be converted and the effective date of the conversion, which date shall not be less than 10 days from the date of the Notice. The Borrower shall, on the effective date specified in the Notice, issue to the Holder as fully paid and non-assessable such number of Common Shares as may be required to convert the amount of principal specified in the notice at the rate aforesaid and upon the issuance of such Shares the principal amount of the Note shall be reduced accordingly.

4.0 INTERPRETATION

4.1 A copy of this Agreement signed by both parties shall be attached to Promissory Note Number 1 and Promissory Note Number 2 and shall form a part thereof.

4.2 Except as amended herein Promissory Note Number 1 and Promissory Note Number 2 shall remain in full force and effect and the Borrower hereby reaffirms its obligations to the Holder pursuant to Promissory Note Number 1 and Promissory Note Number 2 notwithstanding the amendments contained herein.

4.3 This Agreement shall be governed by and interpreted in accordance with the laws of the Province of Ontario.

4.4 This Agreement shall enure to the benefit of and be binding upon the parties hereto and their respective successors and assigns.

IN WITNESS WHEREOF the parties have executed this Agreement on the date first written above.

PUC INC.

Per: ______________________
Brian Curran, President

Per: ______________________
Terry Greco, Treasurer

We have authority to bind the Corporation

PUC DISTRIBUTION INC.

Per: ______________________
Brian Curran, President

Per: ______________________
Terry Greco, Treasurer

We have authority to bind the Corporation

<u>NOTICE</u>

TO: PUC DISTRIBUTION INC.
765 Queen Street East
Sault Ste. Marie, Ontario
P6A 6P2

Re: Exercise of Option – Promissory Note dated August 15th, 2001 (the "Note") between PUC Distribution Inc. (the "Borrower") and PUC Inc. (the "Holder") in the principal amount of Eleven Million Six Hundred and Fifty Thousand Dollars $11,650,000.00 (the "Principal")

TAKE NOTICE that pursuant to paragraph 1.2 of the Note the Holder hereby exercises its option to convert the sum of Eleven Million Six Hundred and Fifty Thousand Dollars ($11,650,000.00) of the Principal into Five Thousand (5,000) Common Shares in the capital stock of the Borrower, effective December 31st, 2008. Upon issuance of the Shares the Note shall be paid in full.

DATED this 18th day of December, 2008.

PUC INC.

Per: B Curran
Brian Curran – President

Per: T Greco
Terry Greco – Treasurer

We have authority to bind the Corporation

<u>NOTICE</u>

TO: PUC DISTRIBUTION INC.
765 Queen Street East
Sault Ste. Marie, Ontario
P6A 6P2

Re: Exercise of Option – Promissory Note dated December 1st , 2001 (the "Note") between PUC Distribution Inc. (the "Borrower") and PUC Inc. (the "Holder") in the principal amount of Thirty Million Two Hundred and Ninety Thousand Dollars <u>$30,290,000.00 (the "Principal")</u>

TAKE NOTICE that pursuant to paragraph 1.2 of the Note the Holder hereby exercises its option to convert the sum of Three Million Seven Hundred and Fifty Five Thousand Nine Hundred and Sixty Dollars ($3,755,960.00) of the Principal into One Thousand Six Hundred and Twelve (1,612) Common Shares in the capital stock of the Borrower, effective December 31st, 2008. Upon issuance of the Shares the Principal of the Note shall be Twenty Six Million and Five Hundred and Thirty Four Thousand and Forty Dollars ($26,534,040).

DATED this 18th day of December, 2008.

PUC INC.

Per: ______________________
Brian Curran – President

Per: ______________________
Terry Greco – Treasurer

We have authority to bind the Corporation

PUC DISTRIBUTION INC. RESOLUTION

Agenda Item # 5.2 **Date:** December 18, 2008

Moved by: LARRY GUERRIERO

Seconded by: RICK WING

Resolution:

"RESOLVED that pursuant to the Notice from PUC Inc. dated December 18th, 2008 delivered to the Corporation and produced to the Board of Directors wherein PUC Inc. exercised its option to convert the principal amount of the Promissory Note between the Corporation as Borrower and PUC Inc. as Holder dated August 15th, 2001 in the amount of $11,650,000.00 into 5,000 common shares in the capital stock of the Corporation at the rate of $2,330.00 per share. The Corporation is hereby authorized to issue to PUC Inc. as at December 31st, 2008, 5000 Common Shares in the capital stock of the Corporation as fully paid and non-assessable and the President of the Corporation is hereby authorized to deliver certificates for such Shares to PUC Inc. or in accordance with its direction.

BE IT FURTHER RESOLVED that pursuant to the Notice from PUC Inc. delivered to the Corporation and produced to the Board of Directors wherein PUC Inc. exercised its option to convert the sum of $3,755,960.00 of the principal of the Promissory Note between the Corporation as Borrower and PUC Inc. as Holder dated December 1st, 2001 in the amount of $30,290,000.00 into 1,612 common shares in the capital stock of the Corporation at the rate of $2,330.00 per share. The Corporation is hereby authorized to issue to PUC Inc. as at December 31st, 2008, 1,612 common shares in the capital stock of the Corporation as fully paid and non-assessable and the President of the Corporation is hereby authorized to deliver certificates for such Shares to PUC Inc. or in accordance with its direction."

☐ **Carried**	☐ **Defeated**	☐ **Deferred**
☐ **Referred**	☐ **Amended**	☐ **Officially Read Not Dealt With**

Chair

Action

☐ **Chair**	☐ **PUC Inc.**	☐ ______
☐ **President**	☐ **PUC Telecom**	☐ ______
☐ **Secretary**	☐ **PUC Services**	☐ ______
☐ **Treasurer**	☐ **PUC Energies**	☐ ______

EXHIBIT 6

CALCULATION OF REVENUE DEFICIENCY OR SUFFICIENCY

PUC Distribution Inc • EB-2022-0059 • Filed: August 31,2022

TABLE OF CONTENTS

LIST OF TABLES

EXHIBIT 6: CALCULATION OF REVENUE DEFICIENCY OR SUFFICIENCY

PUC Distribution Inc. ("PUC") revenue deficiency is $3,918,555. This deficiency is calculated as the difference between the 2023 Test Year Revenue Requirement of $27,752,199 and the Forecast 2023 Test Year Revenue, based on the 2022 approved rates, at $23,833,644, which includes revenues related to ICM applications for PUC's Substation 16 rebuild ("Sub 16") and Sault Smart Grid ("SSG") projects. Table 6-1 on the following page provides the revenue deficiency calculations. The table also includes the determination of net utility income, statement of rate base, the utility return on rate base at existing rates and the requested rate of return on rate base in this application. Further details on these items are provided in the pdf version of the Revenue Requirement Work Form ("RRWF") filed as part of this Exhibit 6, Appendix A. A live Microsoft Excel version of the RRWF has also been filed with this Application.

Revenue Requirement

PUC's Revenue Requirement consists of the following:

- Administrative & General, Billing & Collecting Expenses
- Operation & Maintenance Expenses
- Depreciation Expense
- Property Taxes
- PILs
- Deemed Interest & Return on Equity

PUC's revenue requirement is primarily received through electricity distribution rates with supplemental revenue from Board-approved specific service charges such as late payment charges and other miscellaneous charges.

Table 6-1: Revenue Deficiency Calculation

Description	2023 Test Existing Rates	2023 Test Revenue Requirement
Revenue		
Revenue Deficiency		**3,918,555**
Distribution Revenue	21,083,379	21,083,379
Other Operating Revenue (Net)	2,750,265	2,750,265
Total Revenue	**23,833,644**	**27,752,199**
Costs and Expenses		
Administrative & General, Billing & Collecting	6,253,236	6,253,236
Operation & Maintenance	7,280,465	7,280,465
Donations - LEAP	31,144	31,144
Depreciation & Amortization	5,425,413	5,425,413
Property Taxes	384,446	384,446
Deemed Interest	3,089,225	3,089,225
Total Costs and Expenses	**22,463,928**	**22,463,928**
Utility Income Before Income Taxes	**1,369,716**	**5,288,271**
Income Taxes:		
Corporate Income Taxes	(464,276)	574,141
Total Income Taxes	**(464,276)**	**574,141**
Utility Net Income	**1,833,991**	**4,714,129**
Income Tax Expense Calculation:		
Accounting Income	1,369,716	5,288,271
Tax Adjustments to Accounting Income	(3,121,699)	(3,121,699)
Taxable Income	**(1,751,984)**	**2,166,571**
Income tax expense before credits	**(464,276)**	**574,141**
Credits	**0**	**0**
Income Tax Expense	(464,276)	574,141
Tax Rate Refecting Tax Credits	26.50%	26.50%
Actual Return on Rate Base:		
Rate Base	136,089,188	136,089,188
Interest Expense	3,089,225	3,089,225
Net Income	1,833,991	4,714,129
Total Actual Return on Rate Base	**4,923,216**	**7,803,354**
Actual Return on Rate Base	3.62%	5.73%
Required Return on Rate Base:		
Rate Base	136,089,188	136,089,188
Return Rates:		
Return on Debt (Weighted)	3.78%	3.78%
Return on Equity	8.66%	8.66%
Deemed Interest Expense	3,089,225	3,089,225
Return On Equity	4,714,129	4,714,129
Total Return	**7,803,354**	**7,803,354**
Expected Return on Rate Base	5.73%	5.73%
Revenue Deficiency After Tax	**2,880,138**	**0**
Revenue Deficiency Before Tax	**3,918,555**	**0**

Cost Drivers on Revenue Deficiency

Table 6-2 below outlines the contributors to the revenue deficiency by revenue requirement component. Column A is PUC's 2018 approved amounts. Column B shows PUC's revenue at existing rates, shown in Table 6-1, allocated to revenue requirement component based on the proportions in Column A. Column B estimates the revenue requirement components at existing rates based on the components assumed in existing rates. Column C lists the PUC's proposed components. Finally, column D represents the difference between column C and column B, which provides an proxy of the revenue requirement components for the revenue deficiency of $3,918,555.

Table 6-2: Revenue Deficiency by Revenue Requirement Component

Service Revenue Requirement	2018 Approved (A)	2023 Revenue at Existing Rates Allocated in Proportion to 2018 Approved (B)	2023 Proposed (C)	Revenue Deficiency (D) = (C) - (B)
Load Forecast				697,822
OM&A	11,176,156	12,480,163	13,533,701	1,053,537
Return on Rate Base	5,978,287	6,675,819	7,803,354	1,127,535
Depreciation	3,859,626	4,309,958	5,425,413	1,115,455
Property Tax	343,477	383,553	384,446	893
PILs	586,716	655,173	574,141	($81,031)
LEAP	24,000	26,800	31,144	4,344
Total	21,968,262	24,531,466	27,752,199	**3,918,555**
				Difference (D) = (C) - (A)
Rate Base	99,658,054		136,089,187	36,431,133

Load Forecast - $697,822

PUC's Load Forecast has decreased since its last COS application contributing $697,822 to the total revenue deficiency of $3,918,555. The following table 6-3 compares the 2023 revenue at existing rates using the 2018 Load Forecast to the 2023 Load Forecast. The revenue deficiency includes the calculation of revenue from PUC's ICM applications for Sub 16 and SSG.

Table 6-3: Revenue Deficiency from Load Forecast

Rate Class		2018 Board Approved Load Forecast	2023 Proposed Load Forecast	2022 Rates			2023 Distribution Revenue at 2018 Board Approved Load Forecast		2023 Distribution Revenue at 2023 Proposed Load Forecast	
					Fixed	Variable	Fixed	Variable	Fixed	Variable
Residential	Customers	29,816	30,340	Service Charge	33.72		$ 12,064,746		$ 12,276,778	
	kWh	288,323,799	274,738,681	ICM Sub 16	0.39		$ 139,539		$ 141,991	
	kW			ICM Smart Grid	1.43		$ 511,643		$ 520,634	
							$ 12,715,928		$ 12,939,403	
					Fixed	Variable				
GS<50	Customers	3,431	3,400	Service Charge	22.32	0.0268	$ 918,959	$ 2,476,627	$ 910,656	$ 2,118,581
	kWh	92,411,463	79,051,528	ICM Sub 16	0.26	0.0003	$ 10,705	$ 27,723	$ 10,608	$ 23,715
	kW			ICM Smart Grid	0.95	0.0011	$ 39,113	$ 101,653	$ 38,760	$ 86,957
							$ 968,777	$ 2,606,003	$ 960,024	$ 2,229,253
					Fixed	Variable				
GS>50	Customers	357	344	Service Charge	123.27	7.2479	$ 528,089	$ 4,455,596	$ 508,859	$ 3,969,583
	kWh	244,620,697	221,450,388	ICM Sub 16	1.41	0.0832	$ 6,040	$ 51,147	$ 5,820	$ 45,568
	kW	614,743	547,687	ICM Smart Grid	5.24	0.3082	$ 22,448	$ 189,464	$ 21,631	$ 168,797
							$ 556,577	$ 4,696,206	$ 536,310	$ 4,183,948
					Fixed	Variable				
Sentinel	Customers	354	317	Service Charge	3.83	35.7037	$ 16,270	$ 21,172	$ 14,569	$ 20,217
	kWh	209,800	193,841	ICM Sub 16	0.04	0.4096	$ 14	$ 243	$ 152	$ 232
	kW	593	566	ICM Smart Grid	0.16	1.5182	$ 57	$ 900	$ 609	$ 860
							$ 16,341	$ 22,315	$ 15,330	$ 21,309
					Fixed	Variable				
Street	Customers	8,070	8,037	Service Charge	1.47	9.6161	$ 142,355	$ 67,601	$ 141,773	$ 69,237
	kWh	2,398,221	2,459,994	ICM Sub 16	0.02	0.1103	$ 1,937	$ 775	$ 1,929	$ 794
	kW	7,030	7,200	ICM Smart Grid	0.06	0.4089	$ 5,810	$ 2,875	$ 5,787	$ 2,944
							$ 150,102	$ 71,251	$ 149,488	$ 72,975
					Fixed	Variable				
USL	Customers	22	25	Service Charge	13.67	0.0412	$ 3,609	$ 38,923	$ 4,101	$ 36,195
	kWh	944,731	878,528	ICM Sub 16	0.16	0.0005	$ 42	$ 472	$ 48	$ 439
	kW			ICM Smart Grid	0.58	0.0018	$ 153	$ 1,701	$ 174	$ 1,581
							$ 3,804	$ 41,096	$ 4,323	$ 38,216
				Service Charge			$ 13,674,027	$ 7,059,919	$ 13,856,735	$ 6,213,813
				ICM Sub 16			$ 158,277	$ 80,361	$ 160,549	$ 70,748
				ICM Smart Grid			$ 579,224	$ 296,592	$ 587,594	$ 261,139
							$21,848,401		$21,150,579	
				Revenue Deficiency From Load Forecast			**-$697,822**			

OM&A - $1,053,537

PUC's increase to OM&A includes a combination of inflationary increases, additional staffing requirements for SSG and increased costs from the shared cost allocation review. PUC is managing incremental costs arising from other priority requirements including its Green Button implementation, Cyber Security and additional performance benchmarking activities. The following Table 6-4 breaks down each component with a reference to where the explanation is located in Exhibit 4.

Table 6-4: Revenue Deficiency from OM&A

Total Revenue Deficiency Related to OM&A	$1,053,537	Reference
Increase in OM&A due to Inflation	$447,630	Trend Comparison
Cost Allocation Review, SSG Staffing, Reglatory (Green Button/APB Benchmarking) and Cyber	$605,907	Ex. 4.1.2 Associated Cost

Return on Rate Base - $1,127,535 and Depreciation $1,115,455

PUC had an increase to rate base that was larger than normal due to the approved ICM applications. The inclusion of Sub 16, SSG, other 2018-2022 capital additions, and 2023 test year capital additions has caused a substantial increase to rate base and overall net book value which is summarized in Table 6-5. This was slightly offset by reduced rates for the cost of capital parameters as compared to the 2018 Board Approved application shown in Table 6-6.

Table 6-5: Increase in Net Book Value of Rate Base

	Gross Capital Beginning	Gross Capital End	Acc Dep Beg	Acc Dep End	Average Net Book Value
Sault Smart Grid	$ 21,357,909	$ 21,357,909	$ (300,244)	$ (900,732)	$ 20,757,421
Substation 16	$ 6,020,120	$ 6,020,120	$ (225,754)	$ (376,257)	$ 5,719,114
Gross Capital Additions 5 years	$ 28,193,730	$ 28,193,730	$ (1,881,118)	$ (2,700,510)	$ 25,902,916
2023 Capital Additions	$ -	$ 10,113,371	$ -	$ (94,353.00)	$ 5,009,509
Existing Rate Base	$ 106,264,141	$ 106,264,141	$ (31,516,806)	$ (34,925,626)	$ 73,042,925
Net Book Value	$ 161,835,899	$ 171,949,270	$ (33,923,922)	$ (38,997,478)	$ 130,431,884
				Working Capital Allowance	$ 5,657,302
				2023 Proposed Rate Base	$ 136,089,186

Table 6-6: Cost of Capital Parameters

	2018 Board Approved	2023 Test Year Proposed	Change
Long Term Debt	4.12%	3.97%	(0.15%)
Short Term Debt	2.29%	1.17%	(1.12%)
ROE	9.00%	8.66%	(0.34%)
Weighted Debt Rate	4.00%	3.78%	(0.22%)
Regulated Rate of Return	6.00%	5.73%	(0.27%)

Payment In Lieu of Taxes ("PILS") – ($81,031)

PILS has decreased since the 2018 Board Approved year due to higher projected adjustments to accounting income in the 2023 test year. Adjustments to accounting income are higher because PUC did not fully utilize previous loss carry forwards as part of its 2018 COS application due to a smaller ROE in 2018 and the effect of accelerated CCA. As explained in section 2.6.2.1, PUC did use account 1592 PILS and Tax Variance - CCA to capture the effects of accelerated CCA, however the basis of the entry used actual 2018 capital additions for all years from 2018-2022. Therefore, the difference between each years' actual additions and 2018 actual additions, that formed the basis of the CCA entry, is captured in PUC's loss carry forward balance. In 2021 and 2022, PUC had increased capital additions of $6,020,119 for Sub 16 and $21,357,909 for SSG respectively. This created additional loss carry forwards beyond the 1592 PILS and Tax Variance – CCA.

Also outlined in section 2.6.2.1 PUC is proposing a refund of the loss carry forwards to customers through a rate rider which keeps the adjustments to accounting income in the 2023 Test year at $3,121,699.

LEAP - $4,344

PUC's distribution revenue has increased from $21,888,966 to $27,952,199 causing an increase in LEAP of $7,276 from 2018 Board Approved amount. Table 6-7 shows a summary of this increase. LEAP is a direct function of the other components of revenue requirement since its required that LDC's donate 0.12% of their base revenue requirement. This makes the LEAP deficiency $4,344. LEAP will change as the revenue requirement gets updated throughout the application process. The line that indicates amount used is shown through the application and will be updated during the IR phase to $33,543.

Table 6-7: Revenue Deficiency from LEAP

Year	Revenue Requirement	LEAP %	LEAP Amount
2018	$21,888,966	0.12%	$26,267
2023	$27,952,199	0.12%	$33,543
Amount Used			$31,144
Revenue Deficiency from LEAP			**$7,276**

6.1 REVENUE REQUIREMENT WORK FORM

PUC has completed the 2023_Rev_Reqt_Workform and filed it in Excel live format and as Appendix A to this application. Table 6-8 below is a snapshot of the revenue deficiency/sufficiency calculation.

Table 6-8 Revenue Deficiency/Sufficiency

		Initial Application	
Line No.	**Particulars**	**At Current Approved Rates**	**At Proposed Rates**
1	Revenue Deficiency from Below		$3,918,555
2	Distribution Revenue	$21,083,379	$21,083,379
3	Other Operating Revenue Offsets - net	$2,750,265	$2,750,265
4	**Total Revenue**	$23,833,644	$27,752,199
5	Operating Expenses	$19,374,704	$19,374,704
6	Deemed Interest Expense	$3,089,225	$3,089,225
8	**Total Cost and Expenses**	$22,463,928	$22,463,928
9	**Utility Income Before Income Taxes**	$1,369,716	$5,288,271
10	Tax Adjustments to Accounting Income per 2013 PILs model	($3,121,699)	($3,121,699)
11	**Taxable Income**	($1,751,984)	$2,166,571
12	Income Tax Rate	26.50%	26.50%
13	**Income Tax on Taxable Income**	($464,276)	$574,141
14	**Income Tax Credits**	$ -	$ -
15	**Utility Net Income**	$1,833,991	$4,714,130
16	**Utility Rate Base**	$136,089,188	$136,089,188
17	Deemed Equity Portion of Rate Base	$54,435,675	$54,435,675
18	Income/(Equity Portion of Rate Base)	3.37%	8.66%
19	Target Return - Equity on Rate Base	8.66%	8.66%
20	Deficiency/Sufficiency in Return on Equity	-5.29%	0.00%
21	Indicated Rate of Return	3.62%	5.73%
22	Requested Rate of Return on Rate Base	5.73%	5.73%
23	Deficiency/Sufficiency in Rate of Return	-2.12%	0.00%
24	Target Return on Equity	$4,714,129	$4,714,129
25	Revenue Deficiency/(Sufficiency)	$2,880,138	$0
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,918,555 (1)	

The following Table 6-9 shows the calculation of Bridge Year forecast revenues at existing rates, and the Test Year forecasted revenue at existing and proposed rates.

Table 6-9: Revenue at Existing and Proposed Rates

Rate Class	2022 Rates			2022 Distribution Revenue at Existing Rates		2023 Distribution Revenue at Existing Rates		2023 Distribution Revenue at Existing Rates	
		Fixed	Variable	Fixed	Variable	Fixed	Variable	Fixed	Variable
Residential	Service Charge	33.72		$ 12,235,062		$ 12,276,778		$ 12,064,746	
	ICM Sub 16	0.39		$ 141,509		$ 141,991		$ 139,539	
	ICM Smart Grid	1.43		$ 518,865		$ 520,634		$ 511,643	
				$ 12,895,436		$ 12,939,403		$ 12,715,928	
GS<50		Fixed	Variable						
	Service Charge	22.32	0.0268	$ 909,802	$ 2,317,771	$ 910,656	$ 2,118,581	$ 918,959	$ 2,476,627
	ICM Sub 16	0.26	0.0003	$ 10,598	$ 25,945	$ 10,608	$ 23,715	$ 10,705	$ 27,723
	ICM Smart Grid	0.95	0.0011	$ 38,724	$ 95,132	$ 38,760	$ 86,957	$ 39,113	$ 101,653
				$ 959,124	$ 2,438,849	$ 960,024	$ 2,229,253	$ 968,777	$ 2,606,003
GS>50		Fixed	Variable						
	Service Charge	123.27	7.2479	$ 515,300	$ 4,137,786	$ 508,859	$ 3,969,583	$ 528,089	$ 4,455,596
	ICM Sub 16	1.41	0.0832	$ 5,894	$ 47,498	$ 5,820	$ 45,568	$ 6,040	$ 51,147
	ICM Smart Grid	5.24	0.3082	$ 21,905	$ 175,950	$ 21,631	$ 168,797	$ 22,448	$ 189,464
				$ 543,099	$ 4,361,234	$ 536,310	$ 4,183,948	$ 556,577	$ 4,696,206
Sentinel Light		Fixed	Variable						
	Service Charge	3.83	35.7037	$ 14,870	$ 20,720	$ 14,569	$ 20,217	$ 16,270	$ 21,172
	ICM Sub 16	0.04	0.4096	$ 155	$ 238	$ 152	$ 232	$ 14	$ 243
	ICM Smart Grid	0.16	1.5182	$ 621	$ 881	$ 609	$ 860	$ 57	$ 900
				$ 15,647	$ 21,839	$ 15,330	$ 21,309	$ 16,341	$ 22,315
Street Light		Fixed	Variable						
	Service Charge	1.47	9.6161	$ 141,773	$ 69,237	$ 141,773	$ 69,237	$ 142,355	$ 67,601
	ICM Sub 16	0.02	0.1103	$ 1,929	$ 794	$ 1,929	$ 794	$ 1,937	$ 775
	ICM Smart Grid	0.06	0.4089	$ 5,787	$ 2,944	$ 5,787	$ 2,944	$ 5,810	$ 2,875
				$ 149,488	$ 72,975	$ 149,488	$ 72,975	$ 150,102	$ 71,251
Unemetered Scatted Load		Fixed	Variable						
	Service Charge	13.67	0.0412	$ 4,030	$ 36,183	$ 4,101	$ 36,195	$ 3,609	$ 38,923
	ICM Sub 16	0.16	0.0005	$ 47	$ 439	$ 48	$ 439	$ 42	$ 472
	ICM Smart Grid	0.58	0.0018	$ 171	$ 1,581	$ 174	$ 1,581	$ 153	$ 1,701
				$ 4,248	$ 38,203	$ 4,323	$ 38,216	$ 3,804	$ 41,096
Total									
	Service Charge			$ 13,820,838	$ 6,581,697	$ 13,856,735	$ 6,213,813	$ 13,674,027	$ 7,059,919
	ICM Sub 16			$ 160,132	$ 74,915	$ 160,549	$ 70,748	$ 158,277	$ 80,361
	ICM Smart Grid			$ 586,072	$ 276,488	$ 587,594	$ 261,139	$ 579,224	$ 296,592
				$21,500,141		**$21,150,579**		**$21,848,401**	

6.2 TAXES OR PAYMENT IN LIEU OF TAXES (PILS) AND PROPERTY TAXES

PUC is subject to PILS under Section 93 of the Electricity Act, 1998, as amended. PUC does not pay Section 89 proxy taxes and is exempt from the payment of income and capital taxes under the Income Tax Act (Canada) and the Ontario Corporations Tax Act. A copy of the 2021 Federal T2 Corporate Income Tax Return has been provided in Appendix B to this Exhibit.

PUC confirms that the financial statements filed with its 2021 corporate income tax returns are the same as the 2021 audited financial statements filed with this application.

In accordance with the filing instructions, PUC has completed the Board's PILS Work Form, Version 1.00 and has filed this model in live excel format and as Appendix C.

6.2.1 PILS for the 2023 Test Year

The 2023 Test Year's PILS have been calculated at $498,389. The details of the calculations are in the Income Tax/ PILS Work Form in Appendix C.

The 2023 Test Year PILS have been determined by applying substantively enacted 2023 tax rates against Taxable Income. The 2023 Taxable Income amount has been determined by taking Utility Income before Taxes and applying Schedule 1 corporate tax adjustments to this number.

6.2.2 Utility Income Before Taxes

This is calculated based on the 2023 expected total revenues less the 2023 expected cost and expenses. The Utility income before taxes in 2023 is $5,288,271. The details of this calculation can be found in Table 6-10.

Table 6-10: Utility Income Before Taxes

Description	2023 Test Revenue Requirement
Revenue	
Revenue Deficiency	**3,918,555**
Distribution Revenue	21,083,379
Other Operating Revenue (Net)	2,750,265
Total Revenue	**27,752,199**
Costs and Expenses	
Administrative & General, Billing & Collecting	6,253,236
Operation & Maintenance	7,280,465
Donations - LEAP	31,144
Depreciation & Amortization	5,425,413
Property Taxes	384,446
Deemed Interest	3,089,225
Total Costs and Expenses	**22,463,928**
Utility Income Before Income Taxes	**5,288,271**

6.2.3 Tax Adjustments

Tax adjustments are made for both temporary and permanent differences and reserves. Significant temporary differences included are the differences between depreciation for accounting purposes versus capital cost allowance (CCA) for tax purposes.

The tax provision for the 2023 Test Year is detailed in Table 6-11 as follows:

Table 6-11: PILS Tax Provision 2023 Test Year

PILs Tax Provision - Test Year

	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate				Wires Only
Regulatory Taxable Income							T1	$ 1,351,968
Ontario (Max 11.5%)	11.5%	11.5%	$ 155,476	11.5%	B			
Federal (Max 15%)	15.0%	15.0%	$ 202,795	15.0%	C			
Combined effective tax rate (Max 26.5%)								26.50%
Total Income Taxes								$ 358,271
Investment Tax Credits								
Miscellaneous Tax Credits								
Total Tax Credits								$ -
Corporate PILs/Income Tax Provision for Test Year								$ 358,271
Corporate PILs/Income Tax Provision Gross Up [1]						73.50%	J = 1-D	$ 129,173
Income Tax (grossed-up)								$ 487,444

6.2.4 Expected 2023 Tax Rates

PUC used a combined income tax rate of 26.50% for the 2023 Test Year as presented in Table 6-12.

Table 6-12: Corporate Tax Rates

Corporate Tax Rates for Tax Year:	2022 Bridge	2023 Test
Federal Income Tax	15.00%	15.00%
Ontario Income Tax	11.50%	11.50%
Combined Income Tax	26.50%	26.50%

Tax Calculation

The following Table 6-13 presents the tax calculation for the 2023 Test Year.

Table 6-13: Tax Calculation 2023 Test Year

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	4,714,129
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		5,425,413
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		
Recapture of capital cost allowance from Schedule 8	107	T8	0
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	350,000
Total Additions			**5,775,413**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	8,648,021
Terminal loss from Schedule 8	404	T8	0
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	350,000
Amortization of Contributed Capital			351,857
Adjustment for Bill C-97 CCA Smoothing			-452,766
Total Deductions		calculated	**8,897,112**
NET INCOME FOR TAX PURPOSES		calculated	**1,592,430**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	T4	0
Net capital losses of previous tax years from Schedule 4	332	T4	0
Limited partnership losses of previous tax years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**1,592,430**

6.2.5 Accelerated CCA

On June 21, 2019, Bill C-97 received Royal Assent which allowed LDC's to claim an accelerated investment incentive ("AIIP") on yearly capital additions. Since PUC's last COS application was in 2018, the AIIP was not included as part of the revenue requirement calculation. On July 25, 2019, the OEB provided accounting guidance to record the impacts of the CCA rule change in account 1592 – PILS and Tax Variances. PUC has used account 1592 in accordance with this guidance and the summary is provided in Table 6-14.

Table 6-14: Account 1592 PILS and Tax Variance Calculations

	2018	2019	2020	2021	2022	Total
CCA - OLD RULES	205,202	599,196	961,684	1,295,186	1,396,818	4,458,086
CCA - AIIP RULES	205,202	1,009,600	1,339,269	1,642,577	1,921,632	6,118,280
Increase in CCA	-	410,404	377,585	347,391	524,814	1,660,194
Tax Impact	-	108,757	100,060	92,059	139,076	439,951
Grossed-up	-	147,969	136,136	125,250	189,219	598,573

PUC used the 2018 actual additions as the basis of its CCA calculation and entry for 2018-2022. This creates a projected balance in account 1592 – PILS and Tax Variances of $598,573. The difference between PUC's actual additions and the amounts used as the basis of this entry is captured in PUC's Loss Carry Forwards explained in the section below. The following Tables 6-15 summarizes PUC's Loss Carry forward amounts at the end of each year from 2019-2022 and the amount of loss carry forwards after removing the entry in Account 1592 – PILS and Tax Variances.

Table 6-15: CCA and Loss Carry Forwards

	2018	2019	2020	2021	2022	Total
CCA - OLD RULES	205,202	599,196	961,684	1,295,186	1,396,818	4,458,086
CCA - AIIP RULES	205,202	1,009,600	1,339,269	1,642,577	1,921,632	6,118,280
Increase in CCA	-	410,404	377,585	347,391	524,814	1,660,194
Tax Impact	-	108,757	100,060	92,059	139,076	439,951
Grossed-up	-	147,969	136,136	125,250	189,219	598,573
Cumulative CCA Increase		410,404	787,989	1,135,380	1,660,194	
Non Capital Losses at End of Year		2,581,998	1,792,370	1,999,056	3,915,084	
Non Capital Losses at End of Year (exlucding 1592 entry)		2,171,594	1,004,381	863,676	2,254,890	amount of loss carry forwards to refund to customers

The following tables 6-16 and 6-17 provide the CCA Continuity Schedules for the 2022 Bridge year and 2023 Test year.

Table 6-16: CCA Continuity Schedule 2022

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the bridge year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the bridge year (column 9 minus column 17)
1	Buildings, Distribution System (acq'd post 1987)	H8	$ 35,891,868							$ 35,891,868	$ -	$ -	0.50	$ -	$ -	4%			$ 1,435,675		$ 34,456,193
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	H8	$ 892,076	$ 35,828	$ 35,828					$ 927,904	$ -	$ 35,828	0.50	$ 17,914	$ -	6%			$ 56,749		$ 871,155
2	Distribution System (acq'd pre 1988)	H8	$ -							$ -	$ -	$ -		$ -	$ -	6%			$ -		$ -
3	Buildings (acq'd pre 1988)	H8	$ -							$ -	$ -	$ -		$ -	$ -	5%			$ -		$ -
6	Certain Buildings; Fences	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -
8	General Office Equipment, Furniture, Fixtures	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	20%			$ -		$ -
10	Motor Vehicles, Fleet	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
10.1	Certain Automobiles	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
12	Computer Application Software (Non-Systems)	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	100%			$ -		$ -
14	Limited Period Patents, Franchises, Concessions or Licences	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	H8	$ 1,741,453							$ 1,741,453	$ -	$ -		$ -	$ -	7%			$ 121,902		$ 1,619,551
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	5%			$ -		$ -
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -
42	Fibre Optic Cable	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	H8	$ -							$ -	$ -	$ -		$ -	$ -	45%			$ -		$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
47	Distribution System (acq'd post Feb 22/05)	H8	$ 52,249,054	$ 29,294,205	$ 29,294,205					$ 81,543,259	$ -	$ 29,294,205	0.50	$ 14,647,103	$ -	8%			$ 7,695,229		$ 73,848,030
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	55%			$ -		$ -
95	CWIP	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	0%			$ -		$ -
	TOTALS		**$ 90,774,451**	**$ 29,330,033**	**$ 29,330,033**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 120,104,484**	**$ -**	**$ 29,330,033**		**$ 14,665,016**	**$ -**		**$ -**	**$ -**	**$ 9,309,554**	B1	**$ 110,794,929**

1 **Table 6-17: CCA Continuity Schedule 2023**

2

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the test year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the test year (column 9 minus column 17)
1	Buildings, Distribution System (acq'd post 1987)	B8	$ 34,456,1	Only if election under ONTARIO REGULATION 162/01 ss. 5 or 7 filed in 2001 to have ITR 1102(14) apply						$ 34,456,193	$ -	$ -	0.50	$ -	$ -	4%			$ 1,378,248		$ 33,077,946
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	B8	$ 871,155	577,035	577,035					$ 1,448,189	$ -	$ 577,035	0.50	$ 288,517	$ -	6%			$ 104,202		$ 1,343,987
2	Distribution System (acq'd pre 1988)	B8	$ -							$ -	$ -	$ -		$ -	$ -	6%			$ -		$ -
3	Buildings (acq'd pre 1988)	B8	$ -							$ -	$ -	$ -		$ -	$ -	5%			$ -		$ -
6	Certain Buildings; Fences	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -
8	General Office Equipment, Furniture, Fixtures	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	20%			$ -		$ -
10	Motor Vehicles, Fleet	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
10.1	Certain Automobiles	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
12	Computer Application Software (Non-Systems)	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	100%			$ -		$ -
14	Limited Period Patents, Franchises, Concessions or Licences	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	B8	$ 1,619,551							$ 1,619,551	$ -	$ -		$ -	$ -	7%			$ 113,369		$ 1,506,183
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	5%			$ -		$ -
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -
42	Fibre Optic Cable	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -	$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -	$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	B8	$ -							$ -	$ -	$ -		$ -	$ -	45%			$ -		$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
47	Distribution System (acq'd post Feb 22/05)	B8	$ 73,848,030	9,536,336	9,536,336					$ 83,384,366	$ -	$ 9,536,336	0.50	$ 4,768,168	$ -	8%			$ 7,052,203		$ 76,332,163
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	55%			$ -		$ -
95	CWIP	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	0%			$ -		$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
	TOTALS		$ 110,794,929	$ 10,113,371	$ 10,113,371	$ -	$ -	$ -	$ -	$ 120,908,300	$ -	$ 10,113,371		$ 5,056,685	$ -		$ -	$ -	$ 8,648,021	T1	$ 112,260,279

3

A reconciliation between PUC's December 31, 2021 Undepreciated Capital Cost ("UCC") balance per the filed tax return and the balance used for the opening UCC balance for the 2022 Bridge Year is provided in Table 6-18 as follows:

Table 6-18: Reconciliation of the 2021 UCC Balance

Class Description	Class Number	December 31, 2021 UCC Balance per S(8)	Opening UCC Balance for 2022 Bridge Year
Distribution System - 1988 to 22-Feb-2005	1	$18,842,521	$18,842,521
New Buildings	1	$17,049,347	$17,049,347
New Buildings	1b	$892,076	$892,076
Distribution System - post 22-Feb-2005	47	$52,249,053	$52,249,053
Total		$89,032,997	$89,032,997

6.2.6 Loss Carry Forwards

At the end of 2022, PUC had projected a loss carry forward of $3,915,084 with $1,660,194 of this total is attributed to the 1592 PILS -CCA calculation. As noted above in Table 6-15, PUC is seeking to refund the loss carry forwards to customers through a rate rider with a period of 2 years. PUC chose 2 years which reflects how long it would approximately take PUC to use up these Loss Carry Forwards with its new regulated net income. Table 6-19 summarizes the amount of $812,987 that will be refunded to customers. This methodology is consistent with the treatment of loss carry forwards from PUC's 2018 COS application Decision and Order (EB-2017-0071).

Table 6-19 Loss Carry Forward Refund to Customers

	Loss Carryforward Refund	Accelerated CCA 1592 Refund (2018-2022)	Total (Reconciles to Tax Returns)
Total Loss Carryforward	(2,254,890)	(1,660,194)	(3,915,084)
Tax Rate	26.5%	26.5%	26.5%
Tax Impact	(597,546)	(439,951)	(1,037,497)
Benefit To Customers (Grossed Up)	**(812,987)**	**(598,573)**	**(1,411,561)**

The above calculation results in a refund to customers of $812,987. PUC has allocated the refund to customers based on percentage of revenue requirement as presented in Table 6-20.

Table 6-20: Allocation of Loss Carry Forward

Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	Units	# of Customers	Total Metered kWh	Total Metered kW	Metered kWh for Non-RPP Customers	Metered kW for Non-RPP Customers	Distribution Revenue		Allocation of Loss Carryforward
RESIDENTIAL SERVICE CLASSIFICATION	kWh	30,340	274,738,681	-	271,374,589	3,364,092	$15,291,103	61.4%	(498,950.94)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	3,400	79,051,528	-	66,984,366	12,067,162	$3,768,919	15.1%	(122,980.38)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	344	221,450,388	547,687	40,867,029	188,926,311	$5,498,738	22.1%	(179,424.62)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	25	878,528		878,528		$50,271	0.2%	(1,640.34)
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	317	193,841	566	193,841		$43,297	0.2%	(1,412.80)
STREET LIGHTING SERVICE CLASSIFICATION	kW	8,037	2,459,994	7,200	129,713	2,330,282	$262,895	1.1%	(8,578.31)

The residential class credit is a fixed monthly refund while the remainder of the rate classes will be refunded a volumetric rate as presented in Table 6- 21.

Table 6-21: Loss Carry Forward Rate Rider Refund

Rate Class (Enter Rate Classes in cells below as they appear on your current tariff of rates and charges)	units	Allocation of Loss Carryforward	Billing Determinant	Rate Rider
RESIDENTIAL SERVICE CLASSIFICATION	Customers	($498,951)	30,340	$ (0.69)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	($122,980)	79,051,528	$ (0.0008)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	($179,425)	547,687	$ (0.1638)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	($1,640)	878,528	$ (0.0009)
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	($1,413)	566	$ (1.2481)
STREET LIGHTING SERVICE CLASSIFICATION	kW	($8,578)	7,200	$ (0.5957)

6.2.7 Accelerated CCA Impacts 2023 Test Year

PUC has considered the impacts of the phase out of the Accelerated Investment Incentive ("AIIP") through 2027 in its 2023 Test year. PUC chose to smooth the effects of the phase out of the AIIP which resulted in an adjustment to accounting income of $212,184. The basis of this calculation is shown in Table 6-22 below.

Table 6-22 AII Smoothing 2023-2027

	2023	2024	2025	2026	2027		5 Year Average
Accelerated CCA no phase out	$ 1,178,982	$ 1,178,982	$ 1,178,982	$ 1,178,982	$ 1,178,982	$ 5,894,912	$ 1,178,982
Accelerated CCA phase out	$ 1,178,982	$ 546,358	$ 555,999	$ 511,714	$ 838,031	$ 3,631,084	$ 726,217
CCA Adjustment	$ -	$ 632,625	$ 622,984	$ 667,269	$ 340,951		$ 452,766
					Income		**$ 452,766**

PUC used total net capital additions of $10,113,371 for the Accelerated CCA no phase out line and the DSP projected additions for the Accelerated CCA phase out line as the basis of its calculation. This resulted in a 5-year average adjustment to accounting income of $452,766.

6.2.8 Calculation of Tax Credits

PUC did not include any tax credits, other additions, or deductions in its 2023 Test Year.

6.2.9 Integrity Checks

PUC confirms the following in Table 6-23, Integrity Checks below:

<u>Tabled 6-23: Integrity Checks</u>

	Item	Utility Confirmation (Y/N)	Notes
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y	
2	The capital additions and deductions in the CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y	
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non-distribution tax amounts on Schedule 8.	Y	
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the CCA Schedule 8 for the same years filed in the application	Y	
5	Loss carry-forwards, if any, from prior year tax returns' Schedule 4 agree with those disclosed in the application	Y	
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	Y	
7	CCA is maximized even if there are tax loss carry-forwards	Y	
8	Other post-employment benefits and pension expenses that are added back on Schedule 1 to reconcile accounting income to net income for tax purposes agree with the OM&A analysis for compensation. The amounts deducted are reasonable when compared with the notes to the audited financial statements, Financial Services Commission of Ontario reports, and actuarial valuations.	Y	
9	The income tax rate used to calculate the tax expense is consistent with the utility's actual tax facts and evidence filed in the application	Y	

6.2.10 Property Taxes

PUC pays property taxes to the Corporation of the City of Sault Ste. Marie (the "City"). In addition, PUC makes annual payments to Ontario Electricity Financial Corporation for Payment in Lieu of Property Taxes. Property taxes are billed by the City and calculated using MPAC property values and tax assessment rates. PUC includes property taxes paid to the City in account 4815 and 5012 for transmission and distribution stations respectively. PUC records property taxes for the building in account 6105 – Taxes Other Than Income Taxes. Table 6-24 – Total Taxes, Other than Income below shows the continuity of total property taxes not included in operating expenses for all years up to and including the Test Year.

<u>Table 6-24: Total Taxes, Other than Income</u>

OEB #	Description	2018 Approved	2018	2019	2020	2021	2022 Bridge	2023 Test
6105	Additional Provincial Property PILS	$45,000	$42,144	$39,977	$37,267	$37,927	$39,796	$45,900
6105	Office Building	$298,477	$281,976	$275,299	$267,767	$270,718	$301,919	$338,546
	Total	$343,477	$324,119	$315,276	$305,035	$308,645	$341,715	$384,446

6.2.11 Non-Recoverable and Disallowed Expenses

PUC does not have any expenses that are deducted for general tax purposes but for which recovery in 2023 distribution rates would be disallowed.

6.3 OTHER REVENUE

6.3.1 Variance Analysis of Other Revenue

Other Distribution Revenues are revenues that are distribution related but are sourced from means other than distribution rates. For this reason, other revenues are deducted from PUC's proposed total service revenue requirement. For the 2023 test year PUC has other distribution revenues as $2,750,627 which are explained in detail below.

PUC does not have any discrete customer groups that may be materially impacted by changes to other rates and charges.

Other Distribution revenues include such items as:

- Specific Service Charges;
- Late Payment Charges;
- Other Distribution Revenues; and
- Other Income and Expenses.

A detailed breakdown by USoA account is shown below in Table 6-25 – OEB Appendix 2-H. Year-over-year variance analysis will follow with a discussion on those variances over $135,000.

Table 6-25: OEB Appendix 2-H Other Operating Revenue

Appendix 2-H
Other Operating Revenue

USoA #	USoA Description	2018 Actual[2]	2019 Actual[2]	2020 Actual[2]	2021 Actual	Bridge Year	Test Year
		2018	2019	2020	2021	2022	2023
	Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
4082	Retail Services Revenues	-$ 17,492	-$ 25,442	-$ 26,764	-$ 21,816	-$ 26,000	-$ 26,520
4084	Service Transaction Requests (STR) Revenues	-$ 118	-$ 220	-$ 236	-$ 130	-$ 300	-$ 306
4086	SSS Administration Revenue	-$ 123,056	-$ 124,325	-$ 123,092	-$ 123,974	-$ 125,000	-$ 125,000
4210	Rent from Electric Property	-$ 1,816,886	-$ 2,019,860	-$ 2,031,204	-$ 2,049,392	-$ 1,753,251	-$ 1,732,136
4225	Late Payment Charges	-$ 221,084	-$ 173,679	-$ 296,114	-$ 292,124	-$ 220,000	-$ 230,292
4235	Miscellaneous Service Revenues	-$ 193,432	-$ 161,185	-$ 128,942	-$ 203,119	-$ 152,700	-$ 155,754
4245	Government and Other Assistance Directly Credited to Income	-$ 82,576	-$ 101,862	-$ 123,987	-$ 140,229	-$ 246,348	-$ 351,857
4325	Revenues from Merchandise	-$ 150,893	-$ 94,079	-$ 113,248	-$ 70,544	-$ 100,000	-$ 102,000
4330	Costs and Expenses of Merchandising	$ 476	$ -	$ -			
4355	Gain on Disposition of Utility and Other Property	-$ 80,256	-$ 500	$ -			
4375	Revenues from Non Rate-Regulated Utility Operations	-$ 1,222,816	-$ 4,031,628	-$ 4,731,173	-$ 4,343,196		
4380	Expenses of Non Rate-Regulated Utility Operations	$ 739,618	$ 4,039,777	$ 4,733,226	$ 4,571,650		
4390	Miscellaneous Non-Operating Income	-$ 9,449	-$ 14,378	-$ 56,060	-$ 36,587	-$ 20,000	-$ 26,400
4405	Interest and Dividend Income	-$ 10,151	-$ 2,919	-$ 459	-$ 4,281	$ -	
Miscellaneous Service Revenues		-$ 193,432	-$ 161,185	-$ 128,942	-$ 203,119	-$ 152,700	-$ 155,754
Late Payment Charges		-$ 221,084	-$ 173,679	-$ 296,114	-$ 292,124	-$ 220,000	-$ 230,292
Other Operating Revenues		-$ 2,040,128	-$ 2,271,709	-$ 2,305,283	-$ 2,335,541	-$ 2,150,899	-$ 2,235,819
Other Income or Deductions		-$ 733,471	-$ 103,726	-$ 167,714	$ 117,042	-$ 120,000	-$ 128,400
Total		-$ 3,188,114	-$ 2,710,298	-$ 2,898,054	-$ 2,713,741	-$ 2,643,599	-$ 2,750,265

Table 6-26: 2018 Actual Comparison to 2019 Actual – Other Operating Revenue

Other Distribution Revenue	2018 Actual	2019 Actual	Difference $	Difference %
Specific Service Charges	($193,432)	($161,185)	$32,247	(17%)
Late Payment Charges	($221,084)	($173,679)	$47,405	(21%)
Other Operating Revenues	($2,040,128)	($2,271,709)	($231,581)	11%
Other Income or Deductions	($733,471)	($103,726)	$629,745	(86%)
Total	($3,188,114)	($2,710,298)	$477,816	(15%)

Other operating revenues for 2019 were 15% or $477,816 lower than the 2018 actuals, due mainly to the offset of CDM revenues vs. CDM expenses. In 2018 the CDM revenues were $483,198 higher than CDM expenses. In 2019, CDM Revenue was $8,149 lower than CDM expenses. This contributed a total of $491,347 to the $629,745 reduction in other income or deductions that will be offset in future years. The other main difference was PUC had a gain on disposition of property in 2018 for $80,256.

Other operating revenues were 11% or $231,581 higher in 2019 due to higher pole attachment rental rates.

Table 6-27: 2019 Actual Comparison to 2020 Actual – Other Operating Revenue

Other Distribution Revenue	2019 Actual	2020 Actual	Difference $	Difference %
Specific Service Charges	($161,185)	($128,942)	$32,243	(20%)
Late Payment Charges	($173,679)	($296,114)	($122,435)	70%
Other Operating Revenues	($2,271,709)	($2,305,283)	($33,575)	1%
Other Income or Deductions	($103,726)	($167,714)	($63,988)	62%
Total	($2,710,298)	($2,898,054)	($187,755)	7%

The total of other revenues was 7.00% or $187,755 higher in 2020 compared to 2019. The main contributing factor was higher late payment charges in 2020 due to the COVID-19 pandemic.

Table 6-28: 2020 Actual Comparison to 2021 Actual – Other Operating Revenue

Other Distribution Revenue	2020 Actual	2021 Actual	Difference $	Difference %
Specific Service Charges	($128,942)	($203,119)	($74,177)	58%
Late Payment Charges	($296,114)	($292,124)	$3,990	(1%)
Other Operating Revenues	($2,305,283)	($2,335,541)	($30,257)	1%
Other Income or Deductions	($167,714)	$117,042	$284,756	(170%)
Total	($2,898,054)	($2,713,741)	$184,312	(6%)

The total of other revenues was 6% or $184,312 lower in 2021 compared to 2020.

Other Income or Deductions was $284,756 lower in 2021 due to CDM expenses being higher than CDM revenues. This is the same offset that pertains to the 2018 balance that equalizes itself out. PUC processed more applications in 2021 and therefore had higher CDM expenses compared to CDM revenues.

Table 6-29 2021 Actual Comparison to 2022 Bridge – Other Operating Revenue

Other Distribution Revenue	2021 Actual	2022 Bridge	Difference $	Difference %
Specific Service Charges	($203,119)	($152,700)	$50,419	(25%)
Late Payment Charges	($292,124)	($220,000)	$72,124	(25%)
Other Operating Revenues	($2,335,541)	($2,150,899)	$184,642	(8%)
Other Income or Deductions	$117,042	($120,000)	($237,042)	(203%)
Total	($2,713,741)	($2,643,599)	$70,143	(3%)

The total of other revenues was 3% or $70,143 lower in 2022 compared to 2021.

Other Operating Revenues were 8% or $184,642 lower in 2022 compared to 2021 due to lower pole attachment rates that PUC is allowed to charge.

Other Income or Deductions is projected to be 203% or $237,042 higher in 2022 compared to 2021. This difference is attributable to no longer having CDM revenue and CDM expenses in 2022.

Table 6-30: 2022 Bridge Comparison to 2023 Test – Other Operating Revenue

Other Distribution Revenue	2022 Bridge	2023 Test Year	Difference $	Difference %
Specific Service Charges	($152,700)	($155,754)	($3,054)	2%
Late Payment Charges	($220,000)	($230,292)	($10,292)	5%
Other Operating Revenues	($2,150,899)	($2,235,819)	($84,920)	4%
Other Income or Deductions	($120,000)	($128,400)	($8,400)	7%
Total	($2,643,599)	($2,750,265)	($106,666)	4%

Other Distribution Revenue is within 4% of prior year and there are no variances greater than materiality.

6.3.2 Account Breakdown Details

The following tables provide a breakdown for each other operating revenue and other income or deductions account.

Other Operating Revenue

The accounts PUC records other operating revenues in include; 4082- Retail Service Revenues, 4220 – Other Electric Revenues, 4210 – Rent from Electric Property, and 4245 – Government and Other Assistance. The tables that show the sub accounts contained within each of these accounts from Appendix 2-H is shown below.

Table 6-31 Other Operating Revenue

4082-Retail Services Revenues	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Retailer Fixed	-$ 4,320	-$ 6,920	-$ 7,515	-$ 7,355	-$ 7,000	-$ 7,140
Retailer Variable	-$ 8,233	-$ 11,576	-$ 12,044	-$ 9,055	-$ 12,000	-$ 12,240
Distribution Bill Ready Fee	-$ 4,940	-$ 6,946	-$ 7,205	-$ 5,406	-$ 7,000	-$ 7,140
Total	-$ 17,492	-$ 25,442	-$ 26,764	-$ 21,816	-$ 26,000	-$ 26,520

4220-Other Electric Revenues	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
SSS Admin Charge	-$ 123,056	-$ 124,325	-$ 123,092	-$ 123,974	-$ 125,000	-$ 125,000
Total	-$ 123,056	-$ 124,325	-$ 123,092	-$ 123,974	-$ 125,000	-$ 125,000

4210-Rent from Electric Property	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Building Charge	-$ 1,332,391	-$ 1,220,957	-$ 1,195,271	-$ 1,177,752	-$ 1,070,245	-$ 1,035,470
Land Rent	-$ 7,685	-$ 7,685	-$ 7,685	-$ 7,685	-$ 7,685	-$ 7,839
Pole Rentals	-$ 476,810	-$ 791,218	-$ 828,248	-$ 863,954	-$ 675,321	-$ 688,827
Total	-$ 1,816,886	-$ 2,019,860	-$ 2,031,204	-$ 2,049,392	-$ 1,753,251	-$ 1,732,136

4245-Government and Other Assistance Directly Credited to Income	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Contributions and Grant After 2014	-$ 82,576	-$ 101,862	-$ 123,987	-$ 140,229	-$ 246,348	-$ 351,857
Total	-$ 82,576	-$ 101,862	-$ 123,987	-$ 140,229	-$ 246,348	-$ 351,857

Accounts 4082 and 4220 have no material variances for explanation from 2018 to the 2023 test year.

Account 4210 includes the shared administrative building. A significant portion of the operating activities of the PUC group of companies are carried out in a shared building/facility at 500 Second Line East, which is owned by PUC. The portion of the building used by affiliates is made available by PUC under a lease arrangement. The lease is priced to affiliates at fully allocated cost. PUC confirms that it follows Article 340 (Allocation of Costs and Transfer Pricing) of the Accounting Procedures Handbook as it relates to these charges.

Account 4210 also includes Pole Rentals which has fluctuated from 2018-2023. The OEB provided accounting guidance in its letter "Accounting Guidance on Wireline Pole Attachment Charges, dated July 20, 2018; and created a new variance account, Account 1508 – Sub-Account Pole Attachment Revenue Variance to record the incremental revenue arising from the changes to the pole attachment charge. In 2018, the pole attachment charge was initially updated from $22.35

to $28.09 September 1, 2018 until December 31, 2018 and adjusted to the OEB rate of $43.63 effective January 1, 2019. The rate was again adjusted to $44.50 on January 1, 2020.

In 2019, the OEB release the following accounting order allowing LDC's to charge the pre-approved rate which was adjusted by inflation each year. PUC charged this rate until the new consultation came into place in 2022 reducing the amount PUC could charge for pole rental. PUC estimated its pole rental based on this revised rate which dropped the projected revenue accordingly.

Account 4245 – Government and other assistance directly credited to income has seen a steady increase until 2022. In 2022, the NRCan funding received is added to rate base significantly increasing the amount recorded in this account in 2022 and 2023.

<u>Other Income and Deductions</u>

The accounts that PUC records other operating revenues in include, 4325 – Revenues from Merchandise, 4330 - Costs and Expenses of Merchandising, 4355 – Gain on Disposition of Utility and Other Property, 4375 – CDM Revenues, 4380 – CDM Expenses, 4390 – Miscellaneous Non-Operating Utility Income, and 4405 – Interest and Dividend Income. The tables that show the sub-accounts contained within each of these accounts from Appendix 2-H is shown below.

Table 6-32: Other Income and Deductions

4325-Revenues from Merchandise						
	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Revenues from Merchandise	-$ 150,893	-$ 94,079	-$ 113,248	-$ 70,544	-$ 100,000	-$ 102,000
Total	-$ 150,893	-$ 94,079	-$ 113,248	-$ 70,544	-$ 100,000	-$ 102,000

4330 - Costs and Expenses of Merchandising						
	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Job Sales	$ 476					
Total	$ 476	$ -	$ -	$ -	$ -	$ -

4355 - Gain on disposition of Utility and Other Property						
	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Gain on Disposition of Property	-$ 80,256	-$ 500				
Total	-$ 80,256	-$ 500	$ -	$ -	$ -	$ -

4375 Revenues from Non Rate Regulated Utility Operations						
	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
CDM Revenues	-$ 1,222,816	-$ 4,031,628	-$ 4,731,173	-$ 4,343,196		
Total	-$ 1,222,816	-$ 4,031,628	-$ 4,731,173	-$ 4,343,196	$ -	$ -

4380 Expenses from Non Rate Regulated Utility Operations						
	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
CDM Expenses	$ 739,618	$ 4,039,777	$ 4,733,226	$ 4,571,650		
Total	$ 739,618	$ 4,039,777	$ 4,733,226	$ 4,571,650	$ -	$ -

4390 - Misc Non-Operating Income						
	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Sale of Scrap Metal	-$ 9,449	-$ 14,378	-$ 56,060	-$ 36,587	-$ 20,000	-$ 26,400
Total	-$ 9,449	-$ 14,378	-$ 56,060	-$ 36,587	-$ 20,000	-$ 26,400

4405-Interest and Dividend Income						
	2018 Actual²	2019 Actual²	2020 Actual²	2021 Actual	Bridge Year	Test Year
	2018	2019	2020	2021	2022	2023
Reporting Basis	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS	MIFRS
Interest and Dividend Income	-$ 8,828	-$ 2,343				
Regulatory Carrying Charges	-$ 1,323	-$ 575	-$ 459	-$ 4,281		
Total	-$ 10,151	-$ 2,919	-$ 459	-$ 4,281	$ -	$ -

APPENDIX A

2023 Revenue Requirement Work Form

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Version 1.00

Utility Name	PUC Distribution Inc.
Service Territory	*Sault Ste. Marie*
Assigned EB Number	Eb-2022-0059
Name and Title	Tyler Kasubeck, Regulatory Financial Analyst
Phone Number	705-987-2095
Email Address	tyler.kasubeck@ssmpuc.com
Test Year	2022
Bridge Year	2023
Last Rebasing Year	2018

The RRWF has been enhanced commencing with 2017 rate applications to provide estimated base distribution rates. The enhanced RRWF is not intended to replace a utility's formal rate generator model which should continue to be the source of the proposed rates as well as the final ones at the conclusion of the proceeding. The load forecasting addition made to this model is intended to be demonstrative only and does not replace the information filed in the utility's application. In an effort to minimize the incremental work required from utilities, the cost allocation and rate design additions to this model do in fact replace former appendices that were required to be filed as part of the cost of service (Chapter 2) filing requirements.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Notes:

(1)	Pale green cells represent inputs
(2)	Pale green boxes at the bottom of each page are for additional notes
(3)	Pale yellow cells represent drop-down lists
(4)	***Please note that this model uses MACROS. Before starting, please ensure that macros have been enabled.***
(5)	***Completed versions of the Revenue Requirement Work Form are required to be filed in working Microsoft Excel format.***

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Data Input [1]

		Initial Application				Per Board Decision	
			(2)		(6)		
1	**Rate Base**						
	Gross Fixed Assets (average)	$166,892,585		$ 166,892,585		$166,892,585	
	Accumulated Depreciation (average)	($36,460,700)	(5)	($36,460,700)		($36,460,700)	
	Allowance for Working Capital:						
	Controllable Expenses	$13,949,291		$ 13,949,291		$13,949,291	
	Cost of Power	$61,481,413		$ 61,481,413		$61,481,413	
	Working Capital Rate (%)	7.50%	(9)		(9)		(9)
2	**Utility Income**						
	Operating Revenues:						
	Distribution Revenue at Current Rates	$21,083,379					
	Distribution Revenue at Proposed Rates	$25,001,934					
	Other Revenue:						
	Specific Service Charges	$26,520					
	Late Payment Charges	$230,292					
	Other Distribution Revenue	$2,365,053					
	Other Income and Deductions	$128,400					
	Total Revenue Offsets	$2,750,265	(7)				
	Operating Expenses:						
	OM+A Expenses	$13,533,701		$ 13,533,701		$13,533,701	
	Depreciation/Amortization	$5,425,413		$ 5,425,413		$5,425,413	
	Property taxes	$384,446		$ 384,446		$384,446	
	Other expenses	$31,144		31144		$31,144	
3	**Taxes/PILs**						
	Taxable Income:						
	Adjustments required to arrive at taxable income	($3,121,699)	(3)				
	Utility Income Taxes and Rates:						
	Income taxes (not grossed up)	$421,994					
	Income taxes (grossed up)	$574,141					
	Federal tax (%)	15.00%					
	Provincial tax (%)	11.50%					
	Income Tax Credits	$ -					
4	**Capitalization/Cost of Capital**						
	Capital Structure:						
	Long-term debt Capitalization Ratio (%)	56.0%					
	Short-term debt Capitalization Ratio (%)	4.0%	(8)		(8)		(8)
	Common Equity Capitalization Ratio (%)	40.0%					
	Prefered Shares Capitalization Ratio (%)						
		100.0%					
	Cost of Capital						
	Long-term debt Cost Rate (%)	3.97%					
	Short-term debt Cost Rate (%)	1.17%					
	Common Equity Cost Rate (%)	8.66%					
	Prefered Shares Cost Rate (%)						

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Base and Working Capital

Rate Base

Line No.	Particulars		Initial Application					Per Board Decision
1	Gross Fixed Assets (average)	(2)	$166,892,585	$ -	$166,892,585	$ -	$166,892,585
2	Accumulated Depreciation (average)	(2)	($36,460,700)	$ -	($36,460,700)	$ -	($36,460,700)
3	Net Fixed Assets (average)	(2)	$130,431,885	$ -	$130,431,885	$ -	$130,431,885
4	Allowance for Working Capital	(1)	$5,657,303	($5,657,303)	$ -	$ -	$ -
5	**Total Rate Base**		$136,089,188	($5,657,303)	$130,431,885	$ -	$130,431,885

(1) Allowance for Working Capital - Derivation

Line No.	Particulars		Initial Application				Per Board Decision
6	Controllable Expenses		$13,949,291	$ -	$13,949,291	$ -	$13,949,291
7	Cost of Power		$61,481,413	$ -	$61,481,413	$ -	$61,481,413
8	Working Capital Base		$75,430,704	$ -	$75,430,704	$ -	$75,430,704
9	Working Capital Rate %	(1)	7.50%	-7.50%	0.00%	0.00%	0.00%
10	Working Capital Allowance		$5,657,303	($5,657,303)	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Utility Income

Line No.	Particulars		Initial Application				Per Board Decision
	Operating Revenues:						
1	Distribution Revenue (at Proposed Rates)		$25,001,934	($25,001,934)	$ -	$ -	$ -
2	Other Revenue	(1)	$2,750,265	($2,750,265)	$ -	$ -	$ -
3	Total Operating Revenues		$27,752,199	($27,752,199)	$ -	$ -	$ -
	Operating Expenses:						
4	OM+A Expenses		$13,533,701	$ -	$13,533,701	$ -	$13,533,701
5	Depreciation/Amortization		$5,425,413	$ -	$5,425,413	$ -	$5,425,413
6	Property taxes		$384,446	$ -	$384,446	$ -	$384,446
7	Capital taxes		$ -	$ -	$ -	$ -	$ -
8	Other expense		$31,144	$ -	$31,144	$ -	$31,144
9	Subtotal (lines 4 to 8)		$19,374,704	$ -	$19,374,704	$ -	$19,374,704
10	Deemed Interest Expense		$3,089,225	($3,089,225)	$ -	$ -	$ -
11	Total Expenses (lines 9 to 10)		$22,463,928	($3,089,225)	$19,374,704	$ -	$19,374,704
12	**Utility income before income taxes**		$5,288,271	($24,662,975)	($19,374,704)	$ -	($19,374,704)
13	Income taxes (grossed-up)		$574,141	$ -	$574,141	$ -	$574,141
14	**Utility net income**		$4,714,130	($24,662,975)	($19,948,845)	$ -	($19,948,845)

Notes

Other Revenues / Revenue Offsets

Note						
(1)	Specific Service Charges	$26,520		$ -		$ -
	Late Payment Charges	$230,292		$ -		$ -
	Other Distribution Revenue	$2,365,053		$ -		$ -
	Other Income and Deductions	$128,400		$ -		$ -
	Total Revenue Offsets	$2,750,265	$ -	$ -	$ -	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Taxes/PILs

Line No.	Particulars	Application		Per Board Decision
	Determination of Taxable Income			
1	Utility net income before taxes	$4,714,129	$ -	$ -
2	Adjustments required to arrive at taxable utility income	($3,121,699)	$ -	$ -
3	Taxable income	$1,592,430	$ -	$ -
	Calculation of Utility income Taxes			
4	Income taxes	$421,994	$421,994	$421,994
6	Total taxes	$421,994	$421,994	$421,994
7	Gross-up of Income Taxes	$152,147	$152,147	$152,147
8	Grossed-up Income Taxes	$574,141	$574,141	$574,141
9	PILs / tax Allowance (Grossed-up Income taxes + Capital taxes)	$574,141	$574,141	$574,141
10	Other tax Credits	$ -	$ -	$ -
	Tax Rates			
11	Federal tax (%)	15.00%	15.00%	15.00%
12	Provincial tax (%)	11.50%	11.50%	11.50%
13	Total tax rate (%)	26.50%	26.50%	26.50%

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Capitalization/Cost of Capital

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		Initial Application			
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$76,209,945	3.97%	$3,025,535
2	Short-term Debt	4.00%	$5,443,568	1.17%	$63,690
3	**Total Debt**	60.00%	$81,653,513	3.78%	$3,089,225
	Equity				
4	Common Equity	40.00%	$54,435,675	8.66%	$4,714,129
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	40.00%	$54,435,675	8.66%	$4,714,129
7	**Total**	100.00%	$136,089,188	5.73%	$7,803,354
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	0.00%	$ -	0.00%	$ -
2	Short-term Debt	0.00%	$ -	0.00%	$ -
3	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
4	Common Equity	0.00%	$ -	0.00%	$ -
5	Preferred Shares	0.00%	$ -	0.00%	$ -
6	**Total Equity**	0.00%	$ -	0.00%	$ -
7	**Total**	0.00%	$130,431,885	0.00%	$ -
		Per Board Decision			
		(%)	($)	(%)	($)
	Debt				
8	Long-term Debt	0.00%	$ -	3.97%	$ -
9	Short-term Debt	0.00%	$ -	1.17%	$ -
10	**Total Debt**	0.00%	$ -	0.00%	$ -
	Equity				
11	Common Equity	0.00%	$ -	8.66%	$ -
12	Preferred Shares	0.00%	$ -	0.00%	$ -
13	**Total Equity**	0.00%	$ -	0.00%	$ -
14	**Total**	0.00%	$130,431,885	0.00%	$ -

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Deficiency/Sufficiency

		Initial Application				Per Board Decision	
Line No.	Particulars	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates	At Current Approved Rates	At Proposed Rates
1	Revenue Deficiency from Below		$3,918,555		($2,324,728)		$26,360,141
2	Distribution Revenue	$21,083,379	$21,083,379	$21,083,379	$27,326,662	$ -	($26,360,141)
3	Other Operating Revenue Offsets - net	$2,750,265	$2,750,265	$ -	$ -	$ -	$ -
4	**Total Revenue**	$23,833,644	$27,752,199	$21,083,379	$25,001,934	$ -	$ -
5	Operating Expenses	$19,374,704	$19,374,704	$19,374,704	$19,374,704	$19,374,704	$19,374,704
6	Deemed Interest Expense	$3,089,225	$3,089,225	$ -	$ -	$ -	$ -
8	**Total Cost and Expenses**	$22,463,928	$22,463,928	$19,374,704	$19,374,704	$19,374,704	$19,374,704
9	**Utility Income Before Income Taxes**	$1,369,716	$5,288,271	$1,708,675	$5,627,230	($19,374,704)	($19,374,704)
10	Tax Adjustments to Accounting Income per 2013 PILs model	($3,121,699)	($3,121,699)	($3,121,699)	($3,121,699)	$ -	$ -
11	**Taxable Income**	($1,751,984)	$2,166,571	($1,413,024)	$2,505,531	($19,374,704)	($19,374,704)
12	Income Tax Rate	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
13	**Income Tax on Taxable Income**	($464,276)	$574,141	$ -	$663,966	$ -	$ -
14	**Income Tax Credits**	$ -	$ -	$ -	$ -	$ -	$ -
15	**Utility Net Income**	$1,833,991	$4,714,130	$1,708,675	($19,948,845)	($19,374,704)	($19,948,845)
16	**Utility Rate Base**	$136,089,188	$136,089,188	$130,431,885	$130,431,885	$130,431,885	$130,431,885
17	Deemed Equity Portion of Rate Base	$54,435,675	$54,435,675	$ -	$ -	$ -	$ -
18	Income/(Equity Portion of Rate Base)	3.37%	8.66%	0.00%	0.00%	0.00%	0.00%
19	Target Return - Equity on Rate Base	8.66%	8.66%	0.00%	0.00%	0.00%	0.00%
20	Deficiency/Sufficiency in Return on Equity	-5.29%	0.00%	0.00%	0.00%	0.00%	0.00%
21	Indicated Rate of Return	3.62%	5.73%	1.31%	0.00%	-14.85%	0.00%
22	Requested Rate of Return on Rate Base	5.73%	5.73%	0.00%	0.00%	0.00%	0.00%
23	Deficiency/Sufficiency in Rate of Return	-2.12%	0.00%	1.31%	0.00%	-14.85%	0.00%
24	Target Return on Equity	$4,714,129	$4,714,129	$ -	$ -	$ -	$ -
25	Revenue Deficiency/(Sufficiency)	$2,880,138	$0	($1,708,675)	$ -	$19,374,704	$ -
26	**Gross Revenue Deficiency/(Sufficiency)**	$3,918,555 (1)		($2,324,728) (1)		$26,360,141 (1)	

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Revenue Requirement

Line No.	Particulars	Application				Per Board Decision	
1	OM&A Expenses	$13,533,701		$13,533,701		$13,533,701	
2	Amortization/Depreciation	$5,425,413		$5,425,413		$5,425,413	
3	Property Taxes	$384,446		$384,446		$384,446	
5	Income Taxes (Grossed up)	$574,141		$574,141		$574,141	
6	Other Expenses	$31,144		$31,144		$31,144	
7	Return						
	Deemed Interest Expense	$3,089,225		$ -		$ -	
	Return on Deemed Equity	$4,714,129		$ -		$ -	
8	**Service Revenue Requirement (before Revenues)**	$27,752,199		$19,948,845		$19,948,845	
9	Revenue Offsets	$2,750,265		$ -		$ -	
10	**Base Revenue Requirement (excluding Tranformer Owership Allowance credit adjustment)**	$25,001,934		$19,948,845		$19,948,845	
11	Distribution revenue	$25,001,934		$ -		$ -	
12	Other revenue	$2,750,265		$ -		$ -	
13	**Total revenue**	$27,752,199		$ -		$ -	
14	**Difference (Total Revenue Less Distribution Revenue Requirement before Revenues)**	$0	(1)	($19,948,845)	(1)	($19,948,845)	(1)

Summary Table of Revenue Requirement and Revenue Deficiency/Sufficiency

	Application		Δ% (2)	Per Board Decision	Δ% (2)
Service Revenue Requirement	$27,752,199	$19,948,845	**(28.1%)**	$19,948,845	**(100.0%)**
Grossed-Up Revenue Deficiency/(Sufficiency)	$3,918,555	($2,324,728)	**(159%)**	$26,360,141	**(100.0%)**
Base Revenue Requirement (to be recovered from Distribution Rates)	$25,001,934	$19,948,845	**(20.2%)**	$19,948,845	**(100.0%)**
Revenue Deficiency/(Sufficiency) Associated with Base Revenue Requirement	$3,918,555	$ -	**(100%)**	$ -	**(100.0%)**

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Load Forecast Summary

This spreadsheet provides a summary of the customer and load forecast on which the test year revenue requirement is derived. The amounts serve as the denominators for deriving the rates to recover the test year revenue requirement for purposes of this RRWF.

The information to be input is inclusive of any adjustments to kWh and kW to reflect the impacts of CDM programs up to and including CDM programs planned to be executed in the test year. i.e., the load forecast adjustments determined in **Appendix 2-I** should be incorporated into the entries. The inputs should correspond with the summary of the Load Forecast for the Test Year in **Appendix 2-IB** and in Exhibit 3 of the application.

Appendix 2-IB is still required to be filled out, as it also provides a year-over-year variance analysis of demand growth andf trends from historical actuals to the Bridge and Test Year forecasts.

Stage in Process: Initial Application

	Customer Class	Initial Application						Per Board Decision		
	Input the name of each customer class.	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual	**Customer / Connections** Test Year average or mid-year	**kWh** Annual	**kW/kVA** (1) Annual
1	Residential	30,340	274,738,681							
2	GS<50	3,400	79,051,528							
3	GS>50	344	221,450,388	547,687						
4	Sentinel	317	193,841	566						
5	Street Lights	8,037	2,459,994	7,200						
6	Unmetered Scattered Load	25	878,528							
7										
8										
9										
10										
11										
12										
13										
14										
15										
16										
17										
18										
19										
20										
	Total		**578,772,961**	**555,454**		**-**	**-**		**-**	**-**

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Cost Allocation and Rate Design

This spreadsheet replaces **Appendix 2-P** and provides a summary of the results from the Cost Allocation spreadsheet, and is used in the determination of the class revenue requirement and, hence, ultimately, the determination of rates from customers in all classes to recover the revenue requirement.

Stage in Application Process: ***Initial Application***

A) Allocated Costs

	Name of Customer Class [3] From Sheet 10. Load Forecast	Costs Allocated from Previous Study [1]	%	Allocated Class Revenue Requirement [1] (7A)	%
1	Residential	$ 11,226,807	58.50%	$ 17,128,169	61.72%
2	GS<50	$ 3,149,458	16.41%	$ 3,501,771	12.62%
3	GS>50	$ 4,544,464	23.68%	$ 6,667,329	24.02%
4	Sentinel	$ 34,742	0.18%	$ 52,120	0.19%
5	Street Lights	$ 195,345	1.02%	$ 349,542	1.26%
6	Unmetered Scattered Load	$ 39,551	0.21%	$ 53,269	0.19%
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 19,190,367	100.00%	**$ 27,752,200**	100.00%
			Service Revenue Requirement (from Sheet 9)	**$ 27,752,198.87**	

(1) Class Allocated Revenue Requirement, from Sheet O-1, Revenue to Cost || RR, row 40, from the Cost Allocation Study in this application. This excludes costs in deferral and variance accounts. For Embedded Distributors, Account 4750 - Low Voltage (LV) Costs are also excluded.

(2) Host Distributors - Provide information on any embedded distributor(s) as a separate class, if applicable. If embedded distributors are billed in a General Service class, include the allocated costs and revenues of the embedded distributor(s) in the applicable class, and also complete Appendix 2-Q.

(3) Customer Classes - If these differ from those in place in the previous cost allocation study, modify the customer classes to match the proposal in the current application as closely as possible.

B) Calculated Class Revenues

	Name of Customer Class	Load Forecast (LF) X current approved rates (7B)	LF X current approved rates X (1+d) (7C)	LF X Proposed Rates (7D)	Miscellaneous Revenues (7E)
1	Residential	$ 12,939,404	$ 15,344,319	$ 15,344,319	$ 1,774,752
2	GS<50	$ 3,189,277	$ 3,782,036	$ 3,782,036	$ 345,328
3	GS>50	$ 4,653,058	$ 5,517,875	$ 5,517,875	$ 559,803
4	Sentinel	$ 36,638	$ 43,448	$ 43,448	$ 8,575
5	Street Lights	$ 222,463	$ 263,810	$ 263,810	$ 53,728
6	Unmetered Scattered Load	$ 42,539	$ 50,446	$ 50,446	$ 8,079
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					
	Total	$ 21,083,379	$ 25,001,934	$ 25,001,934	$ 2,750,265

C) Rebalancing Revenue-to-Cost Ratios

	Name of Customer Class	Previously Approved Ratios Most Recent Year: 2018 %	Status Quo Ratios (7C + 7E) / (7A) %	Proposed Ratios (7D + 7E) / (7A) %	Policy Range %
1	Residential	92.62%	99.95%	99.95%	85 - 115
2	GS<50	116.08%	117.87%	117.87%	80 - 120
3	GS>50	111.07%	91.16%	91.16%	80 - 120
4	Sentinel	97.22%	99.81%	99.81%	80 - 120
5	Street Lights	120.00%	90.84%	90.84%	80 - 120
6	Unmetered Scattered Load	112.71%	109.87%	109.87%	80 - 120
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(8) Previously Approved Revenue-to-Cost (R/C) Ratios - For most applicants, the most recent year would be the third year (at the latest) of the Price Cap IR period. For example, if the applicant, rebased in 2012 with further adjustments to move within the range over two years, the Most Recent Year would be 2015. However, the ratios in 2015 would be equal to those after the adjustment in 2014.

(9) Status Quo Ratios - The OEB-issued cost allocation model provides the Status Quo Ratios on Worksheet O-1. The Status Quo means "Before Rebalancing".

(10) Ratios shown in red are outside of the allowed range. Applies to both Tables C and D.

(D) Proposed Revenue-to-Cost Ratios [11]

	Name of Customer Class	Proposed Revenue-to-Cost Ratio Test Year	Price Cap IR Period 1	2	Policy Range
1	Residential	99.95%	99.95%	99.95%	85 - 115
2	GS<50	117.87%	117.87%	117.87%	80 - 120
3	GS>50	91.16%	91.16%	91.16%	80 - 120
4	Sentinel	99.81%	99.81%	99.81%	80 - 120
5	Street Lights	90.84%	90.84%	90.84%	80 - 120
6	Unmetered Scattered Load	109.87%	109.87%	109.87%	80 - 120
7					
8					
9					
10					
11					
12					
13					
14					
15					
16					
17					
18					
19					
20					

(11) The applicant should complete Table D if it is applying for approval of a revenue-to-cost ratio in 2021 that is outside of the OEB's policy range for any customer class. Table D will show that the distributor is likely to enter into the 2022 and 2023 Price Cap IR models, as necessary. For 2022 and 2023, enter the planned revenue-to-cost ratios that will be "Change" or "No Change" in 2019 (in the current Revenue/Cost Ratio Adjustment Workform, Worksheet C1.1 'Decision - Cost Revenue Adjustment, column d), and enter TBD for class(es) that will be entered as 'Rebalance'.

Ontario Energy Board

Revenue Requirement Workform (RRWF) for 2023 Filers

Rate Design and Revenue Reconciliation

This sheet replaces Appendix 2-V, and provides a simplified model for calculating the standard monthly and voluemtric rates based on the allocated class revenues and fixed/variable split resulting from the cost allocation study and rate design and as proposed by the applicant. However, the RRWF does not replace the rate generator model that an applicant distributor may use in support of its application. The RRWF provides a demonstrative check on the derivation of the revenue requirement and on the proposed base distribution rates to recover the revenue requirement, based on summary information from a more detailed rate generator model and other models that applicants use for cost allocation, load forecasting, taxes/PILs, etc.

Stage in Process: *Initial Application*

	Customer and Load Forecast					Class Allocated Revenues: From Sheet 11. Cost Allocation and Sheet 12. Residential Rate Design			Fixed / Variable Splits [2]: Percentage to be entered as a fraction between 0 and 1			Distribution Rates: Monthly Service Charge		Distribution Rates: Volumetric Rate			Revenue Reconciliation		
	Customer Class (From sheet 10. Load Forecast)	Volumetric Charge Determinant	Customers / Connections	kWh	kW or kVA	Total Class Revenue Requirement	Monthly Service Charge	Volumetric	Fixed	Variable	Transformer Ownership Allowance [1] ($)	Rate	No. of decimals	Rate		No. of decimals	MSC Revenues	Volumetric revenues	Revenues less Transformer Ownership Allowance
1	Residential	kWh	30,340	274,738,681	-	$ 15,344,319	$ 15,344,319	$ -	100.00%	0.00%		$42.15	2	$0.0000	/kWh	4	$15,345,972.00	$ -	$15,345,972.00
2	GS<50	kWh	3,400	79,051,528	-	$ 3,782,036	$ 1,138,454	$ 2,643,582	30.10%	69.90%		$27.90		$0.0334	/kWh		$ 1,138,320.00	$ 2,640,321.0193	$ 3,778,641.02
3	GS>50	kW	344	221,450,388	547,687	$ 5,517,875	$ 635,988	$ 4,881,887	11.53%	88.47%	$ 67,200	$154.07		$9.0363	/kW		$ 636,000.96	$ 4,949,067.4246	$ 5,517,868.38
4	Sentinel	kW	317	193,841	566	$ 43,448	$ 18,179	$ 25,269	41.84%	58.16%		$4.78		$44.6252	/kW		$ 18,183.12	$ 25,268.9099	$ 43,452.03
5	Street Lights	kW	8,037	2,459,994	7,200	$ 263,810	$ 177,272	$ 86,538	67.20%	32.80%		$1.84		$12.0191	/kW		$ 177,456.96	$ 86,538.3002	$ 263,995.26
6	Unmetered Scattered Load	kWh	25	878,528	-	$ 50,446	$ 5,127	$ 45,319	10.16%	89.84%		$17.09		$0.0516	/kWh		$ 5,127.00	$ 45,332.0581	$ 50,459.06
7			-	-	-												$ -	$ -	$ -
8			-	-	-												$ -	$ -	$ -
9			-	-	-												$ -	$ -	$ -
10			-	-	-												$ -	$ -	$ -
11			-	-	-												$ -	$ -	$ -
12			-	-	-												$ -	$ -	$ -
13			-	-	-												$ -	$ -	$ -
14			-	-	-												$ -	$ -	$ -
15			-	-	-												$ -	$ -	$ -
16			-	-	-												$ -	$ -	$ -
17			-	-	-												$ -	$ -	$ -
18			-	-	-												$ -	$ -	$ -
19			-	-	-												$ -	$ -	$ -
20			-	-	-												$ -	$ -	$ -

Total Transformer Ownership Allowance $ 67,200

Total Distribution Revenues	$25,000,387.75
Base Revenue Requirement	$25,001,933.81
Difference	-$ 1,546.06
% Difference	-0.006%

Rates recover revenue requirement

Notes:

[1] Transformer Ownership Allowance is entered as a positive amount, and only for those classes to which it applies.

APPENDIX B

2021 Corporate Income Tax Return

200

Canada Revenue Agency / Agence du revenu du Canada

T2 Corporation Income Tax Return

055 Do not use this area

This form serves as a federal, provincial, and territorial corporation income tax return, unless the corporation is located in Quebec or Alberta. If the corporation is located in one of these provinces, you have to file a separate provincial corporation return.

All legislative references on this return are to the federal Income Tax Act and Income Tax Regulations. This return may contain changes that had not yet become law at the time of publication.

Send one completed copy of this return, including schedules and the General Index of Financial Information (GIFI), to your tax centre. You have to file the return within six months after the end of the corporation's tax year.

For more information see **canada.ca/taxes** or Guide T4012, T2 Corporation – Income Tax Guide.

Identification

Business number (BN) **001** 86709 6778 RC0001

Corporation's name
002 PUC Distribution Inc.

Address of head office
Has this address changed since the last time we were notified? . . . . **010** Yes [ ] No [X]
If **yes**, complete lines 011 to 018.
011 500 Second Line East
012
City: **015** Sault Ste Marie
Province, territory, or state: **016** ON
Country (other than Canada): **017**
Postal or ZIP code: **018** P6B 4K1

Mailing address (if different from head office address)
Has this address changed since the last time we were notified? . . . . **020** Yes [ ] No [X]
If **yes**, complete lines 021 to 028.
021 c/o
022
023
City: **025**
Province, territory, or state: **026**
Country (other than Canada): **027**
Postal or ZIP code: **028**

Location of books and records (if different from head office address)
Has this address changed since the last time we were notified? . . . . **030** Yes [ ] No [X]
If **yes**, complete lines 031 to 038.
031
032
City: **035**
Province, territory, or state: **036**
Country (other than Canada): **037**
Postal or ZIP code: **038**

040 **Type of corporation at the end of the tax year** (tick one)
- [ ] 1 Canadian-controlled private corporation (CCPC)
- [ ] 2 Other private corporation
- [ ] 3 Public corporation
- [ ] 4 Corporation controlled by a public corporation
- [X] 5 Other corporation (specify) Electricity Act

If the type of corporation changed during the tax year, provide the effective date of the change . . . . **043** Year Month Day

To which tax year does this return apply?
Tax year start (Year Month Day) **060** 2021-01-01
Tax year-end (Year Month Day) **061** 2021-12-31

Has there been an acquisition of control resulting in the application of subsection 249(4) since the tax year start on line 060? . . . . **063** Yes [ ] No [X]

If **yes**, provide the date control was acquired . . . . **065** Year Month Day

Is the date on line 061 a deemed tax year-end according to subsection 249(3.1)? . . . . **066** Yes [ ] No [X]

Is the corporation a professional corporation that is a member of a partnership? . . . . **067** Yes [ ] No [X]

Is this the first year of filing after:
Incorporation? . . . . **070** Yes [ ] No [X]
Amalgamation? . . . . **071** Yes [ ] No [X]
If **yes**, complete lines 030 to 038 and attach Schedule 24.

Has there been a wind-up of a subsidiary under section 88 during the current tax year? . . . . **072** Yes [ ] No [X]
If **yes**, complete and attach Schedule 24.

Is this the final tax year before amalgamation? . . . . **076** Yes [ ] No [X]

Is this the final return up to dissolution? . . . . **078** Yes [ ] No [X]

If an election was made under section 261, state the functional currency used **079**

Is the corporation a resident of Canada? **080** Yes [X] No [ ]
If **no**, give the country of residence on line 081 and complete and attach Schedule 97.
081

Is the non-resident corporation claiming an exemption under an income tax treaty? . . . . **082** Yes [ ] No [X]
If **yes**, complete and attach Schedule 91.

If the corporation is exempt from tax under section 149, tick one of the following boxes:
085
- [ ] 1 Exempt under paragraph 149(1)(e) or (l)
- [ ] 2 Exempt under paragraph 149(1)(j)
- [ ] 4 Exempt under other paragraphs of section 149

Do not use this area
095 **096** **898**

Attachments

Financial statement information: Use GIFI schedules 100, 125, and 141.

Schedules – Answer the following questions. For each **yes** response, **attach** the schedule to the T2 return, unless otherwise instructed.

		Yes	Schedule
Is the corporation related to any other corporations?	150	X	9
Is the corporation an associated CCPC?	160	X	23
Is the corporation an associated CCPC that is claiming the expenditure limit?	161		49
Does the corporation have any non-resident shareholders who own voting shares?	151		19
Has the corporation had any transactions, including section 85 transfers, with its shareholders, officers, or employees, other than transactions in the ordinary course of business? Exclude non-arm's length transactions with non-residents	162		11
If you answered **yes** to the above question, and the transaction was between corporations not dealing at arm's length, were all or substantially all of the assets of the transferor disposed of to the transferee?	163		44
Has the corporation paid any royalties, management fees, or other similar payments to residents of Canada?	164		14
Is the corporation claiming a deduction for payments to a type of employee benefit plan?	165		15
Is the corporation claiming a loss or deduction from a tax shelter?	166		T5004
Is the corporation a member of a partnership for which a partnership account number has been assigned?	167		T5013
Did the corporation, a foreign affiliate controlled by the corporation, or any other corporation or trust that did not deal at arm's length with the corporation have a beneficial interest in a non-resident discretionary trust (without reference to section 94)?	168		22
Did the corporation own any shares in one or more foreign affiliates in the tax year?	169		25
Has the corporation made any payments to non-residents of Canada under subsections 202(1) and/or 105(1) of the Income Tax Regulations?	170		29
Did the corporation have a total amount over CAN$1 million of reportable transactions with non-arm's length non-residents?	171		T106
For private corporations: Does the corporation have any shareholders who own 10% or more of the corporation's common and/or preferred shares?	173	X	50
Has the corporation made payments to, or received amounts from, a retirement compensation plan arrangement during the year?	172		
Does the corporation earn income from one or more Internet web pages or websites?	180		88
Is the net income/loss shown on the financial statements different from the net income/loss for income tax purposes?	201	X	1
Has the corporation made any charitable donations; gifts of cultural or ecological property; or gifts of medicine?	202		2
Has the corporation received any dividends or paid any taxable dividends for purposes of the dividend refund?	203	X	3
Is the corporation claiming any type of losses?	204	X	4
Is the corporation claiming a provincial or territorial tax credit or does it have a permanent establishment in more than one jurisdiction?	205	X	5
Has the corporation realized any capital gains or incurred any capital losses during the tax year?	206		6
i) Is the corporation a CCPC and reporting a) income or loss from property (other than dividends deductible on line 320 of the T2 return), b) income from a partnership, c) income from a foreign business, d) income from a personal services business, e) income referred to in clause 125(1)(a)(i)(C) or 125(1)(a)(i)(B), f) aggregate investment income as defined in subsection 129(4), or g) an amount assigned to it under subsection 125(3.2) or 125(8); or ii) Is the corporation a member of a partnership and assigning its specified partnership business limit to a designated member under subsection 125(8)?	207		7
Does the corporation have any property that is eligible for capital cost allowance?	208	X	8
Does the corporation have any resource-related deductions?	212		12
Is the corporation claiming deductible reserves?	213		13
Is the corporation claiming a patronage dividend deduction?	216		16
Is the corporation a credit union claiming a deduction for allocations in proportion to borrowing or a provincial credit union tax reduction?	217		17
Is the corporation an investment corporation or a mutual fund corporation?	218		18
Is the corporation carrying on business in Canada as a non-resident corporation?	220		20
Is the corporation claiming any federal, provincial, or territorial foreign tax credits, or any federal logging tax credits?	221		21
Does the corporation have any Canadian manufacturing and processing profits?	227		27
Is the corporation claiming an investment tax credit?	231		31
Is the corporation claiming any scientific research and experimental development (SR&ED) expenditures?	232		T661
Is the total taxable capital employed in Canada of the corporation and its related corporations over $10,000,000?	233	X	33/34/35
Is the total taxable capital employed in Canada of the corporation and its associated corporations over $10,000,000?	234	X	
Is the corporation subject to gross Part VI tax on capital of financial institutions?	238		38
Is the corporation claiming a Part I tax credit?	242		42
Is the corporation subject to Part IV.1 tax on dividends received on taxable preferred shares or Part VI.1 tax on dividends paid?	243		43
Is the corporation agreeing to a transfer of the liability for Part VI.1 tax?	244		45
For financial institutions: Is the corporation a member of a related group of financial institutions with one or more members subject to gross Part VI tax?	250		39
Is the corporation claiming a Canadian film or video production tax credit?	253		T1131
Is the corporation claiming a film or video production services tax credit?	254		T1177
Is the corporation claiming a Canadian journalism labour tax credit?	272		58
Is the corporation subject to Part XIII.1 tax? (Show your calculations on a sheet that you identify as Schedule 92.)	255		92

Attachments (continued)

		Yes	Schedule
Did the corporation have any foreign affiliates in the tax year?	271		T1134
Did the corporation own or hold specified foreign property where the total cost amount of all such property, at any time in the year, was more than CAN$100,000?	259		T1135
Did the corporation transfer or loan property to a non-resident trust?	260		T1141
Did the corporation receive a distribution from or was it indebted to a non-resident trust in the year?	261		T1142
Has the corporation entered into an agreement to allocate assistance for SR&ED carried out in Canada?	262		T1145
Has the corporation entered into an agreement to transfer qualified expenditures incurred in respect of SR&ED contracts?	263		T1146
Has the corporation entered into an agreement with other associated corporations for salary or wages of specified employees for SR&ED?	264		T1174
Did the corporation pay taxable dividends (other than capital gains dividends) in the tax year?	265	X	55
Has the corporation made an election under subsection 89(11) not to be a CCPC?	266		T2002
Has the corporation revoked any previous election made under subsection 89(11)?	267		T2002
Did the corporation (CCPC or deposit insurance corporation (DIC)) pay eligible dividends, or did its general rate income pool (GRIP) change in the tax year?	268		53
Did the corporation (other than a CCPC or DIC) pay eligible dividends, or did its low rate income pool (LRIP) change in the tax year?	269		54
Is the corporation claiming a return of fuel charge proceeds to farmers tax credit?	273		63
Are you an employer reporting a non-qualified security agreement under subsection 110(1.9)?	274		59
Is the corporation claiming an air quality improvement tax credit?	275		65

Additional information

		Yes	No
Did the corporation use the International Financial Reporting Standards (IFRS) when it prepared its financial statements?	270	X	
Is the corporation inactive?	280		X

What is the corporation's main revenue-generating business activity? ..... 221122 Electric Power Distribution

Specify the principal products mined, manufactured, sold, constructed, or services provided, giving the approximate percentage of the total revenue that each product or service represents.

284	Electrical power distribution	285	100.000 %
286		287	%
288		289	%

		Yes	No
Did the corporation immigrate to Canada during the tax year?	291		X
Did the corporation emigrate from Canada during the tax year?	292		X
Do you want to be considered as a quarterly instalment remitter if you are eligible?	293		

If the corporation was eligible to remit instalments on a quarterly basis for part of the tax year, provide the date the corporation ceased to be eligible ..... 294 Year Month Day

If the corporation's major business activity is construction, did you have any subcontractors during the tax year? ..... 295 Yes ☐ No ☐

Taxable income

Net income or (loss) for income tax purposes from Schedule 1, financial statements, or GIFI			300	-432,110 A
Deduct:				
Charitable donations from Schedule 2	311			
Cultural gifts from Schedule 2	313			
Ecological gifts from Schedule 2	314			
Gifts of medicine made before March 22, 2017, from Schedule 2	315			
Taxable dividends deductible under section 112 or 113, or subsection 138(6) from Schedule 3	320			
Part VI.1 tax deduction*	325			
Non-capital losses of previous tax years from Schedule 4	331			
Net capital losses of previous tax years from Schedule 4	332			
Restricted farm losses of previous tax years from Schedule 4	333			
Farm losses of previous tax years from Schedule 4	334			
Limited partnership losses of previous tax years from Schedule 4	335			
Taxable capital gains or taxable dividends allocated from a central credit union	340			
Prospector's and grubstaker's shares	350			
Employer deduction for non-qualified securities	352			
Subtotal			►	B
Subtotal (amount A **minus** amount B) (if negative, enter "0")				C
Section 110.5 additions or subparagraph 115(1)(a)(vii) additions			355	D
Taxable income (amount C **plus** amount D)			360	
Taxable income for the year from a personal services business				Z.1

* This amount is equal to 3.5 times the Part VI.1 tax payable at line 724 on page 9.

Small business deduction

Canadian-controlled private corporations (CCPCs) throughout the tax year

Income eligible for the small business deduction from Schedule 7 . . . . . **400** ______ A

Taxable income from line 360 on page 3, **minus** 100/28 (3.57143) of the amount on line 632* on page 8, **minus** 4 times the amount on line 636** on page 8, and **minus** any amount that, because of federal law, is exempt from Part I tax . . . . . **405** ______ B

Business limit (see notes 1 and 2 below) . . . . . **410** 500,000 C

Notes:

1. For CCPCs that are not associated, enter $ 500,000 on line 410. However, if the corporation's tax year is less than 51 weeks, prorate this amount by the number of days in the tax year **divided** by 365, and enter the result on line 410.
2. For associated CCPCs, use Schedule 23 to calculate the amount to be entered on line 410.

Business limit reduction

Taxable capital business limit reduction

Amount C 500,000 x **415** *** 259,557 D / 11,250 = ... 11,535,867 E

Passive income business limit reduction

Adjusted aggregate investment income from Schedule 7**** . **417** 940,164 – 50,000 = . . 890,164 F

Amount C 500,000 / 100,000 x Amount F 890,164 = ... 4,450,820 G

The greater of amount E and amount G **422** 11,535,867 H

Reduced business limit (amount C **minus** amount H) (if negative, enter "0") . . . . . **426** ______ I

Business limit the CCPC assigns under subsection 125(3.2) (from line 515 below) . . . . . ______ J

Reduced business limit after assignment (amount I **minus** amount J) . . . . . **428** ______ K

Small business deduction – Amount A, B, C, or K, whichever is the least . . . . ______ x 19 % = **430** ______

Enter amount from line 430 at amount J on page 8.

* Calculate the amount of foreign non-business income tax credit deductible on line 632 without reference to the refundable tax on the CCPC's investment income (line 604) and without reference to the corporate tax reductions under section 123.4.

** Calculate the amount of foreign business income tax credit deductible on line 636 without reference to the corporation tax reductions under section 123.4.

*** **Large corporations**

- If the corporation is not associated with any corporations in both the current and previous tax years, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **prior** year **minus** $10,000,000) x 0.225%.
- If the corporation is not associated with any corporations in the current tax year, but was associated in the previous tax year, the amount to be entered on line 415 is: (total taxable capital employed in Canada for the **current** year **minus** $10,000,000) x 0.225%.
- For corporations associated in the current tax year, see Schedule 23 for the special rules that apply.

**** Enter the total adjusted aggregate investment income of the corporation and all associated corporations for each tax year that ended in the preceding calendar year. Each corporation with such income has to file a Schedule 7. For a corporation's first tax year that starts after 2018, this amount is reported at line 744 of the corresponding Schedule 7. Otherwise, this amount is the total of all amounts reported at line 745 of the corresponding Schedule 7 of the corporation for each tax year that ended in the preceding calendar year.

Specified corporate income and assignment under subsection 125(3.2)

	L1 Name of corporation receiving the income and assigned amount	L Business number of the corporation receiving the assigned amount **490**	M Income paid under clause 125(1)(a)(i)(B) to the corporation identified in column L [3] **500**	N Business limit assigned to corporation identified in column L [4] **505**
1.				
			Total **510** ______	Total **515** ______

Notes:

3. This amount is [as defined in subsection 125(7) **specified corporate income** (a)(i)] the total of all amounts each of which is income (other than specified farming or fishing income of the corporation for the year) from an active business of the corporation for the year from the provision of services or property to a private corporation (directly or indirectly, in any manner whatever) if
   (A) at any time in the year, the corporation (or one of its shareholders) or a person who does not deal at arm's length with the corporation (or one of its shareholders) holds a direct or indirect interest in the private corporation, and
   (B) it is not the case that all or substantially all of the corporation's income for the year from an active business is from the provision of services or property to
   (I) persons (other than the private corporation) with which the corporation deals at arm's length, or
   (II) partnerships with which the corporation deals at arm's length, other than a partnership in which a person that does not deal at arm's length with the corporation holds a direct or indirect interest.
4. The amount of the business limit you assign to a CCPC cannot be greater than the amount determined by the formula A – B, where A is the amount of income referred to in column M in respect of that CCPC and B is the portion of the amount described in A that is deductible by you in respect of the amount of income referred to in clauses 125(1)(a)(i)(A) or (B) for the year. The amount on line 515 cannot be greater than the amount on line 426.

General tax reduction for Canadian-controlled private corporations

Canadian-controlled private corporations throughout the tax year

Taxable income from line 360 on page 3				A
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		B		
Amount 13K from Part 13 of Schedule 27		C		
Personal services business income	432	D		
Amount from line 400, 405, 410, or 428 on page 4, whichever is the least		E		
Aggregate investment income from line 440 on page 6*		F		
Subtotal (**add** amounts B to F)		▶		G
Amount A **minus** amount G (if negative, enter "0")				H
General tax reduction for Canadian-controlled private corporations – Amount H **multiplied** by 13 %				I

Enter amount I on line 638 on page 8.

* Except for a corporation that is, throughout the year, a cooperative corporation (within the meaning assigned by subsection 136(2)) or a credit union.

General tax reduction

Do not complete this area if you are a Canadian-controlled private corporation, an investment corporation, a mortgage investment corporation, a mutual fund corporation, or any corporation with taxable income that is not subject to the corporation tax rate of 38%.

Taxable income from line 360 on page 3				J
Lesser of amounts 9B and 9H from Part 9 of Schedule 27		K		
Amount 13K from Part 13 of Schedule 27		L		
Personal services business income	434	M		
Subtotal (**add** amounts K to M)		▶		N
Amount J **minus** amount N (if negative, enter "0")				O
General tax reduction – Amount O **multiplied** by 13 %				P

Enter amount P on line 639 on page 8.

Refundable portion of Part I tax

Canadian-controlled private corporations throughout the tax year

Aggregate investment income from Schedule 7 . . . . **440** ______ x 30 2 / 3 % =		. . . . ______	A
Foreign non-business income tax credit from line 632 on page 8	______	B	
Foreign investment income from Schedule 7 . . . . **445** ______ x 8 % =	______	C	
Subtotal (amount B **minus** amount C) (if negative, enter "0")	______ ▶	______	D
Amount A **minus** amount D (if negative, enter "0")		______	E
Taxable income from line 360 on page 3	______	F	

Amount from line 400, 405, 410, or 428 on page 4, whichever is the least	______	G
Foreign non-business income tax credit from line 632 on page 8 . . . . ______ x 75 / 29 =	______	H
Foreign business income tax credit from line 636 on page 8 . . ______ x 4 =	______	I
Subtotal (**add** amounts G to I)	______ ▶ ______	J

Subtotal (amount F **minus** amount J)	______ K x 30 2 / 3 % =	______	L
Part I tax payable minus investment tax credit refund (line 700 **minus** line 780 from page 9)		______	M
Refundable portion of Part I tax – Amount E, L, or M, whichever is the least **450**		______	N

Refundable dividend tax on hand

Refundable dividend tax on hand (RDTOH) at the end of the previous tax year	460			
Dividend refund for the previous tax year	465			
Net RDTOH transferred on an amalgamation or the wind-up of a subsidiary	480			
Subtotal (line 460 **minus** line 465 **plus** line 480)				A
General rate income pool (GRIP) at the end of the previous tax year (from line 100 of Schedule 53)				B
Total eligible dividends paid in the previous tax year (from line 300 of Schedule 53)			C	
Total excessive eligible dividend designation in the previous tax year (from line 310 of Schedule 53)			D	
Subtotal (amount C **minus** amount D) (if negative, enter "0")			▶	E
Net GRIP at the end of the previous tax year (amount B **minus** amount E) (if negative, enter "0")			F	
GRIP transferred on an amalgamation or the wind-up of a subsidiary (total of lines 230 and 240 of Schedule 53)			G	
Subtotal (amount F **plus** amount G)			▶	H
Amount H **multiplied** by 38 1 / 3 %				I
Eligible refundable dividend tax on hand (ERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A or I, whichever is less, otherwise, use line 530 of the preceding tax year)	520			J
Non-eligible refundable dividend tax on hand (NERDTOH) at the end of the previous tax year (for the first tax year starting after 2018, amount A **minus** amount I, otherwise, use line 545 of the preceding tax year) (if negative, enter "0")	535			K
Part IV tax payable on taxable dividends from connected corporations (amount 2G from Schedule 3)			L	
Part IV tax payable on eligible dividends from non-connected corporations (amount 2J from Schedule 3)			M	
Subtotal (amount L **plus** amount M)			▶	N
Net ERDTOH transferred on an amalgamation or the wind-up of a subsidiary	525			O
ERDTOH dividend refund for the previous tax year	570			P
Refundable portion of Part I tax (from line 450 on page 6)				Q
Part IV tax before deductions (amount 2A from Schedule 3)			R	
Part IV tax allocated to ERDTOH (amount N)			S	
Part IV tax reduction due to Part IV.1 tax payable (amount 4D of Schedule 43)			T	
Subtotal (amount R **minus** total of amounts S and T)			▶	U
Net NERDTOH transferred on an amalgamation or the wind-up of a subsidiary	540			V
NERDTOH dividend refund for the previous tax year	575			W
38 1/3% of the total losses applied against Part IV tax (amount 2D from Schedule 3)				X
Part IV tax payable allocated to NERDTOH, net of losses claimed (amount U **minus** amount X) (if negative enter "0")				Y
NERDTOH at the end of the tax year (total of amounts K, Q, V, and Y **minus** amount W) (if negative, enter "0")	545			
Part IV tax payable allocated to ERDTOH, net of losses claimed (amount N **minus** the amount, if any, by which amount X exceeds amount U) (if negative, enter "0")				Z
ERDTOH at the end of the tax year (total of amounts J, O, and Z **minus** amount P) (if negative, enter "0")	530			

Dividend refund

38 1/3% of total eligible dividends paid in the tax year (amount 3A from Schedule 3)		AA
ERDTOH balance at the end of the tax year (line 530)		BB
Eligible dividend refund (amount AA or BB, whichever is less)		CC
38 1/3% of total non-eligible taxable dividends paid in the tax year (amount 3B from Schedule 3)	233,864	DD
NERDTOH balance at the end of the tax year (line 545)		EE
Non-eligible dividend refund (amount DD or EE, whichever is less)		FF
Amount DD **minus** amount EE (if negative, enter "0")	233,864	GG
Amount BB **minus** amount CC (if negative, enter "0")		HH
Additional non-eligible dividend refund (amount GG or HH, whichever is less)		II
Dividend refund – Amount CC **plus** amount FF **plus** amount II		JJ

Enter amount JJ on line 784 on page 9.

Part I tax

Base amount Part I tax – Taxable income (from line 360 on page 3) **multiplied** by 38 % . . . . **550** ______ A

Additional tax on personal services business income (section 123.5)

Taxable income from a personal services business . . . . **555** ______ x 5 % = **560** ______ B

Recapture of investment tax credit from Schedule 31 . . . . **602** ______ C

Calculation for the refundable tax on the Canadian-controlled private corporation's (CCPC) investment income
(if it was a CCPC throughout the tax year)

Aggregate investment income from line 440 on page 6 . . . . ______ D

Taxable income from line 360 on page 3 . . . . ______ E

Deduct:

Amount from line 400, 405, 410, or 428 on page 4, whichever is the least . . . . ______ F

Net amount (amount E **minus** amount F) ______ ► ______ G

Refundable tax on CCPC's investment income – 10 2 / 3 % of whichever is less: amount D or amount G . . . . **604** ______ H

Subtotal (**add** amounts A, B, C, and H) ______ I

Deduct:

Small business deduction from line 430 on page 4 . . . . ______ J

Federal tax abatement . . . . **608** ______

Manufacturing and processing profits deduction from Schedule 27 . . . . **616** ______

Investment corporation deduction . . . . **620** ______

Taxed capital gains **624** ______

Federal foreign non-business income tax credit from Schedule 21 . . . . **632** ______

Federal foreign business income tax credit from Schedule 21 . . . . **636** ______

General tax reduction for CCPCs from amount I on page 5 . . . . **638** ______

General tax reduction from amount P on page 5 . . . . **639** ______

Federal logging tax credit from Schedule 21 . . . . **640** ______

Eligible Canadian bank deduction under section 125.21 . . . . **641** ______

Federal qualifying environmental trust tax credit . . . . **648** ______

Investment tax credit from Schedule 31 . . . . **652** ______

Subtotal ______ ► ______ K

Part I tax payable – Amount I **minus** amount K . . . . ______ L

Enter amount L on line 700 on page 9.

Privacy notice

Personal information (including the SIN) is collected to administer or enforce the Income Tax Act and related programs and activities including administering tax, benefits, audit, compliance, and collection. The information collected may be used or disclosed for the purposes of other federal acts that provide for the imposition and collection of a tax or duty. It may also be disclosed to other federal, provincial, territorial, or foreign government institutions to the extent authorized by law. Failure to provide this information may result in paying interest or penalties, or in other actions. Under the Privacy Act, individuals have a right of protection, access to and correction of their personal information, or to file a complaint with the Privacy Commissioner of Canada regarding the handling of their personal information. Refer to Personal Information Bank CRA PPU 047 on Info Source at **canada.ca/cra-info-source**.

Summary of tax and credits

Federal tax

Part I tax payable from amount L on page 8	700	
Part III.1 tax payable from Schedule 55	710	
Part IV tax payable from Schedule 3	712	
Part IV.1 tax payable from Schedule 43	716	
Part VI tax payable from Schedule 38	720	
Part VI.1 tax payable from Schedule 43	724	
Part XIII.1 tax payable from Schedule 92	727	
Part XIV tax payable from Schedule 20	728	
Total federal tax		

Add provincial or territorial tax:

Provincial or territorial jurisdiction 750 ON
(if more than one jurisdiction, enter "multiple" and complete Schedule 5)

Net provincial or territorial tax payable (except Quebec and Alberta)	760	67,185	
Total tax payable	770	67,185	A

Deduct other credits:

Investment tax credit refund from Schedule 31	780	
Dividend refund from amount JJ on page 7	784	
Federal capital gains refund from Schedule 18	788	
Federal qualifying environmental trust tax credit refund	792	
Return of fuel charge proceeds to farmers tax credit from Schedule 63	795	
Canadian film or video production tax credit (Form T1131)	796	
Film or video production services tax credit (Form T1177)	797	
Canadian journalism labour tax credit from Schedule 58	798	
Air quality improvement tax credit from Schedule 65	799	
Tax withheld at source	800	
Total payments on which tax has been withheld	801	
Provincial and territorial capital gains refund from Schedule 18	808	
Provincial and territorial refundable tax credits from Schedule 5	812	
Tax instalments paid	840	80,276
Total credits	890	80,276 ▶ 80,276 B

Balance (amount A **minus** amount B) -13,091

If the result is negative, you have **a refund**. If the result is positive, you have a **balance owing**.
Enter the amount below on whichever line applies.

Generally, we do not charge or refund a difference of $2 or less.

Refund code 894 1 Refund 13,091 Balance owing

For information on how to enrol for direct deposit, go to **canada.ca/cra-direct-deposit**.

For information on how to make your payment, go to **canada.ca/payments**.

If the corporation is a Canadian-controlled private corporation throughout the tax year, does it qualify for the one-month extension of the date the balance of tax is due? 896 Yes ☐ No ☒

If this return was prepared by a tax preparer for a fee, provide their EFILE number 920 D4481

PREPARED SOLELY FOR INCOME TAX PURPOSES WITHOUT AUDIT OR REVIEW FROM INFORMATION PROVIDED BY THE TAXPAYER.

Certification

I, 950 McLellan (Last name) 951 Kelly (First name) 954 Vice-President Finance (Position, office, or rank),

am an authorized signing officer of the corporation. I certify that I have examined this return, including accompanying schedules and statements, and that the information given on this return is, to the best of my knowledge, correct and complete. I also certify that the method of calculating income for this tax year is consistent with that of the previous tax year except as specifically disclosed in a statement attached to this return.

955 2022-06-24 — Date (yyyy/mm/dd)
Signature of the authorized signing officer of the corporation
956 (705) 759-6566 — Telephone number

Is the contact person the same as the authorized signing officer? If **no**, complete the information below 957 Yes ☒ No ☐

958 Name of other authorized person
959 Telephone number

Language of correspondence – Langue de correspondance

Indicate your language of correspondence by entering **1** for English or **2** for French.
Indiquez votre langue de correspondance en inscrivant **1** pour anglais ou **2** pour français. 990 1

Schedule of Instalment Remittances

Name of corporation contact
Telephone number

Effective interest date	Description (instalment remittance, split payment, assessed credit)	Amount of credit
	Instalments	80,276

Total amount of instalments claimed (carry the result to line 840 of the T2 Return) 80,276 **A**

Total instalments credited to the taxation year per T9 80,276 **B**

Transfer

	Account number	Taxation year end	Amount	Effective interest date	Description
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					
From:					
To:					

Canada Revenue Agency / Agence du revenu du Canada

Net Income (Loss) for Income Tax Purposes

Schedule 1

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

- Use this schedule to reconcile the corporation's net income (loss) as reported on the financial statements and its net income (loss) for tax purposes. For more information, see the T2 Corporation – Income Tax Guide.
- All legislative references are to the Income Tax Act.

Net income (loss) after taxes and extraordinary items from line 9999 of Schedule 125 . . . . . 2,417,255 A

Add:

Provision for income taxes – current	101	71,089	
Provision for income taxes – deferred	102	602,000	
Amortization of tangible assets	104	3,842,226	
Non-deductible meals and entertainment expenses	121	1,623	
Reserves from financial statements – balance at the end of the year	126	348,864	
Subtotal of additions		4,865,802	4,865,802

Add:

Other additions:

	1 Description 605	2 Amount 295
1	Capital Contributions 12(1)(x)	3,674,486
2	Sub16 depreciation (charged to regulatory)	75,251
	Total of column 2	3,749,737

Total of column 2	296	3,749,737		
Subtotal of other additions	199	3,749,737	3,749,737	D
Total additions	500	8,615,539	8,615,539	

Amount A **plus** line 500 . . . . . 11,032,794 B

Deduct:

Capital cost allowance from Schedule 8	403	6,699,325	
Reserves from financial statements – balance at the beginning of the year	414	348,864	
Subtotal of deductions		7,048,189	7,048,189

Deduct:

Non-taxable/deductible other comprehensive income items	347	317,431

Other deductions:

	1 Description 705	2 Amount 395
1	Amortization of contributed capital	140,229
2	Regulatory charges deferred for accounting purposes	284,569
3	ITA 13(7.4) Election - Capital Contributions received	3,674,486
	Total of column 2	4,099,284

Total of column 2	396	4,099,284		
Subtotal of other deductions	499	4,416,715	4,416,715	E
Total deductions	510	11,464,904	11,464,904	

Net income (loss) for income tax purposes (amount B **minus** line 510) . . . . . -432,110 C

Enter amount C on line 300 of the T2 return.

Canada Revenue Agency | Agence du revenu du Canada

Schedule 3

Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

- Corporations must use this schedule to report:
  - non-taxable dividends under section 83
  - deductible dividends under subsection 138(6)
  - taxable dividends deductible from income under section 112, subsection 113(2) and paragraphs 113(1)(a), (a.1), (b) or (d)
  - taxable dividends paid in the tax year that qualify for a dividend refund (see page 3)
- All legislative references are to the federal Income Tax Act.
- The calculations in this schedule apply only to private or subject corporations (as defined in subsection 186(3)).
- A payer corporation is **connected** with a recipient corporation at any time in a tax year, if at that time the recipient corporation meets either of the following conditions:
  - it controls the payer corporation, other than because of a right referred to in paragraph 251(5)(b)
  - it owns more than 10% of the issued share capital (with full voting rights), and shares that have a fair market value of more than 10% of the fair market value of all shares of the payer corporation
- If you need more space, continue on a separate schedule.
- File this schedule with your T2 Corporation Income Tax Return.
- Column A1 – Enter "X" if dividends were received from a foreign source.
  Column F1 – Enter the code that applies to the deductible taxable dividend.

Part 1 – Dividends received in the tax year

- Do **not** include dividends received from foreign non-affiliates.
- Complete columns B, C, D, H, I, I.1 and L **only if** the payer corporation is **connected.**

Important instructions to follow if the payer corporation is connected

- If your corporation's tax year-end is different than that of the **connected** payer corporation, dividends could have been received from more than one tax year of the payer corporation. If so, **use a separate line** to provide the information according to each tax year of the payer corporation.
- When completing columns J, K and L use the **special calculations provided in the notes**.

	A Name of payer corporation (from which the corporation received the dividend) 200	A1	B Enter 1 if payer corporation is **connected** 205	C Business number of **connected** corporation 210	D Tax year-end of the payer corporation in which the sections 112/113 and subsection 138(6) dividends in column F were paid YYYYMMDD 220	E Non-taxable dividends under section 83 230
1			2			
					Total of column E (enter amount on line 402 of Schedule 1)	

Part 1 – Dividends received in the tax year (continued)

	F Taxable dividends deductible from taxable income under section 112, subsections 113(2) and 138(6), and paragraphs 113(1)(a), (a.1),(b), or (d)note 1 240	F1	G Eligible dividends included in column F 242	H Total taxable dividends paid by **connected** payer corporation (for tax year in column D) 250
1				

	I Dividend refund of the **connected** payer corporation (for tax year in column D)note 2 260	I.1 Dividend refund of the **connected** payer corporation from its eligible refundable dividend tax on hand (ERDTOH) (for tax year in column D) notes 2 and 5	J Part IV tax for eligible dividends. Dividends (from column G) **multiplied** by 38 1/3%note 3 265	K Part IV tax before deductions. Dividends (from column F) **multiplied** by 38 1/3%note 4 275	L Part IV tax before deductions on taxable dividends received from **connected** corporations notes 2 and 5 280
1					

Total of column L (enter amount on line 2E in Part 2) ________

Taxable dividends received from connected corporations (total amounts from column F with code 1 in column B) . . . . ________ 1A

Taxable dividends received from non-connected corporations (total amounts from column F with code 2 in column B) . . . . ________ 1B

Subtotal (amount 1A **plus** amount 1B, include this amount on line 320 of the T2 return) ________ 1C

Eligible dividends received from connected corporations (total amounts from column G with code 1 in column B) . . . . ________ 1D

Eligible dividends received from non-connected corporations (total amounts from column G with code 2 in column B) . . . . ________ 1E

Part IV tax before deductions on taxable dividends received from connected corporations (total amounts from column K with code 1 in column B) . . . . ________ 1F

Part IV tax before deductions on taxable dividends received from non-connected corporations (total amounts from column K with code 2 in column B) . . . . ________ 1G

Subtotal (amount 1F **plus** amount 1G) ________ ▶ ________ 1H

Part IV tax on eligible dividends received from connected corporations (total amounts from column J with code 1 in column B) . . . . ________ 1I

Part IV tax on eligible dividends received from non-connected corporations (total amounts from column J with code 2 in column B) . . . . ________ 1J

Subtotal (amount 1I **plus** amount 1J) ________ ▶ ________ 1K

Part IV tax before deductions on taxable dividends (other than eligible dividends) (amount 1H **minus** amount 1K) . . . . ________ 1L

1 If taxable dividends are received, enter the amount in column F, but if the corporation is not subject to Part IV tax (such as a public corporation other than a subject corporation as defined in subsection 186(3)), enter "0" in column K (and column J, if applicable). Life insurers are not subject to Part IV tax on subsection 138(6) dividends.

2 If the connected payer corporation's tax year ends after the corporation's balance-due day for the tax year (two or three months, as applicable), you have to estimate the payer's dividend refund when you calculate the corporation's Part IV tax payable. For column L, you only have to estimate the payer's dividend refund from its eligible refundable dividend tax on hand (ERDTOH) (column I.1).

3 For eligible dividends received from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by column G.

4 For taxable dividends received from **connected** corporations, Part IV tax on dividends is equal to: column I **divided** by column H **multiplied** by column F.

5 For taxable dividends received from connected corporations (with a tax year starting after 2018), Part IV tax on dividends is equal to: total of amounts CC and II of the connected payer corporation (on page 7 of the T2 return) divided by column H multiplied by column F. If there is no dividend refund (or estimated dividend refund) to the connected payer corporation from its ERDTOH for paying the taxable dividends, enter "0" in column L.

Part 2 – Calculation of Part IV tax payable

Part IV tax on dividends received before deductions (amount 1H in part 1)			2A	
Part IV.I tax payable on dividends subject to Part IV tax (from line 360 of Schedule 43)	320			
Subtotal (amount 2A **minus** line 320)			▶	2B
Current-year non-capital loss claimed to reduce Part IV tax	330			
Non-capital losses from previous years claimed to reduce Part IV tax	335			
Current-year farm loss claimed to reduce Part IV tax	340			
Farm losses from previous years claimed to reduce Part IV tax	345			
Total losses applied against Part IV tax (total of lines 330 to 345)			2C	
Amount 2C **multiplied** by 38 1 / 3 %				2D
Part IV tax payable (amount 2B **minus** amount 2D, if negative enter "0") (enter amount on line 712 of the T2 return)	360			

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax before deductions on taxable dividends received from connected corporations (total of column L in part 1)	2E
Amount 4A from Schedule 43	2F
Part IV tax payable on taxable dividends received from connected corporations (amount 2E **minus** amount 2F, if negative enter "0")	2G

(enter at amount L on page 7 of the T2 return)

If your tax year begins after 2018, complete the following part to determine the required amount of Part IV taxes payable in order to calculate the eligible refundable dividend tax on hand (ERDTOH) at the end of the tax year.

Part IV tax on eligible dividends received from non-connected corporations (amount 1J in part 1)	2H
Amount 4C from Schedule 43	2I
Part IV tax payable on eligible dividends received from non-connected corporations (amount 2H **minus** amount 2I, if negative enter "0")	2J

(enter at amount M on page 7 of the T2 return)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund

If your corporation's tax year-end is different than that of the recipient corporation with which you are connected, your corporation could have paid dividends in more than one tax year of the recipient corporation. If so, use a separate line to provide the information according to each tax year of the recipient corporation.

	L Name of recipient corporation with which you are connected 400	M Business number 410	N Tax year-end of recipient corporation in which the dividends in column O were received YYYYMMDD 420	O Taxable dividends paid to recipient corporations with which you are connected 430	P Eligible dividends included in column O 440
1	PUC INC	89839 7518 RC0001	2021-12-31	610,080	
2					
				610,080 (Total of column O)	(Total of column P)

Part 3 – Taxable dividends paid in the tax year that qualify for a dividend refund (continued)

Total taxable dividends paid in the tax year to other than connected corporations			450	
Eligible dividends included in line 450	455			
Total taxable dividends paid in the tax year that qualify for a dividend refund (total of column O **plus** line 450)			460	610,080
Total eligible dividends paid in the tax year (total of column P **plus** line 455)			465	
Total non-eligible taxable dividends paid in the tax year (line 460 **minus** line 465)			470	610,080

Complete this part to determine the following amounts in order to calculate the dividend refund.

Line 465 **multiplied** by 38 1 / 3 % (enter at amount AA on page 7 of the T2 return)		3A
Line 470 **multiplied** by 38 1 / 3 % (enter at amount DD on page 7 of the T2 return)	233,864	3B

Part 4 – Total dividends paid in the tax year

Complete this part **if** the total taxable dividends paid in the tax year that qualify for a dividend refund (line 460) is different from the total dividends paid in the tax year.

Total taxable dividends paid in the tax year for the purposes of a dividend refund (from above)				610,080	
Other dividends paid in the tax year (total of 510 to 540)					
Total dividends paid in the tax year			500	610,080	
Dividends paid out of capital dividend account	510				
Capital gains dividends	520				
Dividends paid on shares described in subsection 129(1.2)	530				
Taxable dividends paid to a controlling corporation that was bankrupt at any time in the year	540				
Subtotal (total of lines 510 to 540)			►		4A
Total taxable dividends paid in the tax year that qualify for a dividend refund (Line 500 **minus** amount 4A)				610,080	4B

T2 SCH 3 E (21)

Canada

Canada Revenue Agency / Agence du revenu du Canada

Schedule 4

Corporation Loss Continuity and Application

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

- Use this form to determine the continuity and use of available losses; to determine a current-year non-capital loss, farm loss, restricted farm loss, or limited partnership loss; to determine the amount of restricted farm loss and limited partnership loss that can be applied in a year; and to ask for a loss carryback to previous years.
- A corporation can choose whether or not to deduct an available loss from income in a tax year. The corporation can deduct losses in any order. However, for each type of loss, deduct the oldest loss first.
- According to subsection 111(4) of the federal Income Tax Act, when control has been acquired, no amount of capital loss incurred for a tax year ending before that time is deductible in computing taxable income in a tax year ending after that time. Also, no amount of capital loss incurred in a tax year ending after that time is deductible in computing taxable income of a tax year ending before that time.
- When control has been acquired, subsection 111(5) provides for similar treatment of non-capital and farm losses, except as listed in paragraphs 111(5)(a) and (b).
- For information on these losses, see the T2 Corporation – Income Tax Guide.
- File this schedule with the T2 return, or send the schedule by itself to the tax centre where the return is filed.
- All legislative references are to the federal Income Tax Act.

Part 1 – Non-capital losses

Determination of current-year non-capital loss

Net income (loss) for income tax purposes			-432,110	1A
Net capital losses deducted in the year (enter as a positive amount)		1B		
Taxable dividends deductible under section 112 or subsections 113(1) or 138(6)		1C		
Amount of Part VI.1 tax deductible under paragraph 110(1)(k)		1D		
Amount deductible as prospector's and grubstaker's shares – Paragraph 110(1)(d.2)		1E		
Employer deduction for non-qualified securities – Paragraph 110(1)(e)		1F		
Subtotal (total of amounts 1B to 1F)		▶		1G
Subtotal (amount 1A **minus** amount 1G; if positive, enter "0"			-432,110	1H
Section 110.5 or subparagraph 115(1)(a)(vii) – Addition for foreign tax deductions				1I
Subtotal (amount 1H **minus** amount 1I)			-432,110	1J
Current-year farm loss (the lesser of: the net loss from farming or fishing included in income and the non-capital loss before deducting the farm loss)				1K
Current-year non-capital loss (amount 1J **plus** amount 1K; if positive, enter "0") If amount 1L is negative, enter it on line 110 as a positive.			-432,110	1L

Continuity of non-capital losses and request for a carryback

Non-capital loss at the end of the previous tax year		1,566,946	1M		
Non-capital loss expired **(note 1)**	100				
Non-capital losses at the beginning of the tax year (amount 1M **minus** line 100)	102	1,566,946	▶	1,566,946	
Non-capital losses transferred on an amalgamation or on the wind-up of a subsidiary **(note 2)** corporation	105				
Current-year non-capital loss (from amount 1L)	110	432,110			
Subtotal (line 105 **plus** line 110)		432,110	▶	432,110	1N
Subtotal (line 102 **plus** amount 1N)				1,999,056	1O

Note 1: A non-capital loss expires after **20 tax years** and an allowable business investment loss becomes a net capital loss after **10 tax years**.

Note 2: Subsidiary is defined in subsection 88(1) as a taxable Canadian corporation of which 90% or more of each class of issued shares are owned by its parent corporation and the remaining shares are owned by persons that deal at arm's length with the parent corporation.

Part 1 – Non-capital losses (continued)

Other adjustments (includes adjustments for an acquisition of control)	150			
Section 80 – Adjustments for forgiven amounts	140			
Subsection 111(10) – Adjustments for fuel tax rebate				
Non-capital losses of previous tax years applied in the current tax year Enter line 130 on line 331 of the T2 return.	130			
Current and previous years non-capital losses applied against current-year taxable dividends subject to Part IV tax **(note 3)**	135			
Subtotal (total of lines 150, 140, 130 and 135)				1P
Non-capital losses before any request for a carryback (amount 1O **minus** amount 1P)			1,999,056	1Q

Request to carry back non-capital loss to:

First previous tax year to reduce taxable income	901			
Second previous tax year to reduce taxable income	902			
Third previous tax year to reduce taxable income	903			
First previous tax year to reduce taxable dividends subject to Part IV tax	911			
Second previous tax year to reduce taxable dividends subject to Part IV tax	912			
Third previous tax year to reduce taxable dividends subject to Part IV tax	913			
Total of requests to carry back non-capital losses to previous tax years (total of lines 901 to 913)				1R
Closing balance of non-capital losses to be carried forward to future tax years (amount 1Q **minus** amount 1R)	180		1,999,056	

Note 3: Line 135 is the total of lines 330 and 335 from Schedule 3, Dividends Received, Taxable Dividends Paid, and Part IV Tax Calculation.

Part 2 – Capital losses

Continuity of capital losses and request for a carryback

Capital losses at the end of the previous tax year	200			
Capital losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	205			
Subtotal (line 200 **plus** line 205)				2A
Other adjustments (includes adjustments for an acquisition of control)	250			
Section 80 – Adjustments for forgiven amounts	240			
Subtotal (line 250 **plus** line 240)				2B
Subtotal (amount 2A **minus** amount 2B)				2C
Current-year capital loss (from the calculation on Schedule 6, Summary of Dispositions of Capital Property)	210			
Unused non-capital losses from the 11th previous tax year **(note 4)**			2D	
Allowable business investment losses (ABILs) that expired as non-capital losses at the end of the previous tax year **(note 5)**			2E	
Enter amount 2D or 2E, whichever is less	215			
ABILs expired as non-capital losses: line 215 **multiplied** by 2.000000	220			
Subtotal (amount 2C **plus** line 210 **plus** line 220)				2F

Note
If there has been an amalgamation or a wind–up of a subsidiary, do a separate calculation of the ABIL expired as non-capital loss for each predecessor or subsidiary corporation. Add all these amounts and enter the total on line 220.

Note 4: Determine the amount of the non-capital loss from the **11th previous tax year**, and enter the part of the non-capital loss that was not deducted in the **previous 11 years**.

Note 5: Enter the amount of the ABILs from the **11th previous tax year**. Enter the full amount on amount 2E.

Part 2 – Capital losses (continued)

Capital losses from previous tax years applied against the current-year net capital gain **(note 6)**			225	
Capital losses before any request for a carryback (amount 2F **minus** line 225)				2G

Request to carry back capital loss to (note 7):

	Capital gain (100%)		Amount carried back (100%)		
First previous tax year		951			
Second previous tax year		952			
Third previous tax year	79,039	953			
Subtotal (total of lines 951 to 953)				▶	2H
Closing balance of capital losses to be carried forward to future tax years (amount 2G **minus** amount 2H) **(note 8)**				280	

Note 6: To get the net capital losses required to reduce the taxable capital gain included in the net income (loss) for the current tax year, enter the amount from line 225 **divided** by 2 at line 332 of the T2 return.

Note 7: On line 225, 951, 952, or 953, whichever applies, enter the actual amount of the loss. When the loss is applied, **divide** this amount by 2. The result represents the 50% inclusion rate.

Note 8: Capital losses can be carried forward indefinitely.

Part 3 – Farm losses

Continuity of farm losses and request for a carryback

Farm losses at the end of the previous tax year		3A		
Farm loss expired **(note 9)**	300			
Farm losses at the beginning of the tax year (amount 3A **minus** line 300)	302		▶	
Farm losses transferred on an amalgamation or on the wind–up of a subsidiary corporation	305			
Current-year farm loss (amount 1K in Part 1)	310			
Subtotal (line 305 **plus** line 310)			▶	3B
Subtotal (line 302 **plus** amount 3B)				3C
Other adjustments (includes adjustments for an acquisition of control)	350			
Section 80 – Adjustments for forgiven amounts	340			
Farm losses of previous tax years applied in the current tax year Enter line 330 on line 334 of the T2 Return.	330			
Current and previous years farm losses applied against current-year taxable dividends subject to Part IV tax **(note 10)**	335			
Subtotal (total of lines 350, 340, 330 and 335)			▶	3D
Farm losses before any request for a carryback (amount 3C **minus** amount 3D)				3E

Request to carry back farm loss to:

First previous tax year to reduce taxable income	921			
Second previous tax year to reduce taxable income	922			
Third previous tax year to reduce taxable income	923			
First previous tax year to reduce taxable dividends subject to Part IV tax	931			
Second previous tax year to reduce taxable dividends subject to Part IV tax	932			
Third previous tax year to reduce taxable dividends subject to Part IV tax	933			
Subtotal (total of lines 921 to 933)			▶	3F
Closing balance of farm losses to be carried forward to future tax years (amount 3E **minus** amount 3F)			380	

Note 9: A farm loss expires after **20 tax years**.

Note 10: Line 335 is the total of lines 340 and 345 from Schedule 3.

Part 4 – Restricted farm losses

Current-year restricted farm loss

Total losses for the year from farming business			485	
(line 485 ______ – $2,500) **divided** by 2		4A		
Amount 4A or $ 15,000 , whichever is less		▶	4B	
		2,500	4C	
Subtotal (amount 4B **plus** amount 4C)		2,500	▶	2,500 4D
Current-year restricted farm loss (line 485 **minus** amount 4D)				4E

Continuity of restricted farm losses and request for a carryback

Restricted farm losses at the end of the previous tax year			4F	
Restricted farm loss expired **(note 11)**	400			
Restricted farm losses at the beginning of the tax year (amount 4F **minus** line 400)	402		▶	
Restricted farm losses transferred on an amalgamation or on the wind-up of a subsidiary corporation	405			
Current-year restricted farm loss (from amount 4E) Enter line 410 on line 233 of Schedule 1, Net Income (Loss) for Income Tax Purposes.	410			
Subtotal (line 405 **plus** line 410)			▶	4G
Subtotal (line 402 **plus** amount 4G)				4H
Restricted farm losses from previous tax years applied against current farming income Enter line 430 on line 333 of the T2 return.	430			
Section 80 – Adjustments for forgiven amounts	440			
Other adjustments	450			
Subtotal (total of lines 430 to 450)			▶	4I
Restricted farm losses before any request for a carryback (amount 4H **minus** amount 4I)				4J

Request to carry back restricted farm loss to:

First previous tax year to reduce farming income	941			
Second previous tax year to reduce farming income	942			
Third previous tax year to reduce farming income	943			
Subtotal (total of lines 941 to 943)			▶	4K
Closing balance of restricted farm losses to be carried forward to future tax years (amount 4J **minus** amount 4K)			480	

Note

The total losses for the year from all farming businesses are calculated without including scientific research expenses.

Note 11: A restricted farm loss expires after **20 tax years**.

Part 5 – Listed personal property losses

Continuity of listed personal property loss and request for a carryback

Listed personal property losses at the end of the previous tax year			5A		
Listed personal property loss expired **(note 12)**	500				
Listed personal property losses at the beginning of the tax year (amount 5A **minus** line 500)	502		▶		
Current-year listed personal property loss (from Schedule 6)			510		
Subtotal (line 502 **plus** line 510)					5B
Listed personal property losses from previous tax years applied against listed personal property gains	530				
Enter line 530 on line 655 of Schedule 6.					
Other adjustments	550				
Subtotal (line 530 **plus** line 550)			▶		5C
Listed personal property losses remaining before any request for a carryback (amount 5B **minus** amount 5C)					5D

Request to carry back listed personal property loss to:

First previous tax year to reduce listed personal property gains	961				
Second previous tax year to reduce listed personal property gains	962				
Third previous tax year to reduce listed personal property gains	963				
Subtotal (total of lines 961 to 963)			▶		5E
Closing balance of listed personal property losses to be carried forward to future tax years (amount 5D **minus** amount 5E)			580		

Note 12: A listed personal property loss expires after **7 tax years**.

Part 7 – Limited partnership losses

Current-year limited partnership losses

1	2	3	4	5	6	7
Partnership account number 600	Tax year ending YYYY/MM/DD 602	Corporation's share of limited partnership loss 604	Corporation's at-risk amount 606	Total of corporation's share of partnership investment tax credit, farming losses, and resource expenses 608	Column 4 **minus** column 5 (if negative, enter "0")	Current -year limited partnership losses (column 3 **minus** column 6) 620
1.						

Total (enter this amount on line 222 of Schedule 1)

Limited partnership losses from previous tax years that may be applied in the current year

1	2	3	4	5	6	7
Partnership account number 630	Tax year ending YYYY/MM/DD 632	Limited partnership losses at the end of the previous tax year and amounts transferred on an amalgamation or on the wind-up of a subsidiary 634	Corporation's at-risk amount 636	Total of corporation's share of partnership investment tax credit, business or property losses, and resource expenses 638	Column 4 **minus** column 5 (if negative, enter "0")	Limited partnership losses that may be applied in the year (the lesser of columns 3 and 6) 650
1.						

Continuity of limited partnership losses that can be carried forward to future tax years

1	2	3	4	5	6
Partnership account number 660	Limited partnership losses at the end of the previous tax year 662	Limited partnership losses transferred in the year on an amalgamation or on the wind-up of a subsidiary 664	Current-year limited partnership losses (from line 620) 670	Limited partnership losses applied in the current year (must be equal to or less than line 650) 675	Current year limited partnership losses closing balance to be carried forward to future years (column 2 **plus** column 3 **plus** column 4 **minus** column 5) 680
1.					

Total (enter this amount on line 335 of the T2 return)

Note

If you need more space, you can attach more schedules.

Part 8 – Election under paragraph 88(1.1)(f)

If you are making an election under paragraph 88(1.1)(f), tick the box . . . . **190** Yes ☐

In the case of the wind-up of a subsidiary, if the election is made, the non-capital loss, restricted farm loss, farm loss, or limited partnership loss of the subsidiary—that otherwise would become the loss of the parent corporation for a particular tax year starting after the wind–up began—will be considered as the loss of the parent corporation for its immediately preceding tax year and not for the particular year.

Note

This election is only applicable for wind-ups under subsection 88(1) that are reported on Schedule 24, First-Time Filer after Incorporation, Amalgamation, or Winding-up of a Subsidiary into a Parent.

Non-Capital Loss Continuity Workchart

Part 6 – Analysis of balance of losses by year of origin

Non-capital losses

Year of origin	Balance at beginning of year	Loss incurred in current year	Adjustments and transfers	Loss carried back Parts I & IV	Applied to reduce Taxable income	Applied to reduce Part IV tax	Balance at end of year
Current	N/A	432,110			N/A		432,110
1st preceding taxation year 2020-12-31		N/A		N/A			
2nd preceding taxation year 2019-12-31		N/A		N/A			
3rd preceding taxation year 2018-12-31	322,782	N/A		N/A			322,782
4th preceding taxation year 2017-12-31	1,244,164	N/A		N/A			1,244,164
5th preceding taxation year 2016-12-31		N/A		N/A			
6th preceding taxation year 2015-12-31		N/A		N/A			
7th preceding taxation year 2014-12-31		N/A		N/A			
8th preceding taxation year 2013-12-31		N/A		N/A			
9th preceding taxation year 2012-12-31		N/A		N/A			
10th preceding taxation year 2011-12-31		N/A		N/A			
11th preceding taxation year 2010-12-31		N/A		N/A			
12th preceding taxation year 2009-12-31		N/A		N/A			
13th preceding taxation year 2008-12-31		N/A		N/A			
14th preceding taxation year 2007-12-31		N/A		N/A			
15th preceding taxation year 2006-12-31		N/A		N/A			
16th preceding taxation year 2005-12-31		N/A		N/A			
17th preceding taxation year 2004-12-31		N/A		N/A			
18th preceding taxation year 2003-12-31		N/A		N/A			
19th preceding taxation year 2002-12-31		N/A		N/A			
20th preceding taxation year 2001-12-31		N/A		N/A			*
Total	1,566,946	432,110					1,999,056

* **This balance expires this year and will not be available next year.**

Canada Revenue Agency | Agence du revenu du Canada

Schedule 5

Tax Calculation Supplementary – Corporations

Corporation's name	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

- Use this schedule if any of the following apply to your corporation during the tax year:
  - it had a permanent establishment in more than one jurisdiction (corporations that have no taxable income should only complete columns A, B, and D in Part 1)
  - it is claiming provincial or territorial tax credits or rebates (see Part 2)
  - it has to pay taxes, other than income tax, for Newfoundland and Labrador or Ontario (see Part 2)
- All legislative references are to the federal Income Tax Regulations (the Regulations).
- For more information, see the T2 Corporation – Income Tax Guide.
- For the regulation number to be entered in field 100 of Part 1, see the chart below.

Part 1 – Allocation of taxable income

100 ______ Enter the regulation that applies (402 to 413)

A Jurisdiction. Tick yes if your corporation had a permanent establishment in the jurisdiction during the tax year Note 1		B Total salaries and wages paid in jurisdiction	C (B x taxable income) / G	D Gross revenue attributable to jurisdiction	E (D x taxable income) / H	F Allocation of taxable income (C + E) x 1/2 Note 2 (where either G or H is nil, do not multiply by 1/2)
Newfoundland and Labrador	003 Yes ☐	103		143		
Newfoundland and Labrador Offshore	004 Yes ☐	104		144		
Prince Edward Island	005 Yes ☐	105		145		
Nova Scotia	007 Yes ☐	107		147		
Nova Scotia Offshore	008 Yes ☐	108		148		
New Brunswick	009 Yes ☐	109		149		
Quebec	011 Yes ☐	111		151		
Ontario	013 Yes ☐	113		153		
Manitoba	015 Yes ☐	115		155		
Saskatchewan	017 Yes ☐	117		157		
Alberta	019 Yes ☐	119		159		
British Columbia	021 Yes ☐	121		161		
Yukon	023 Yes ☐	123		163		
Northwest Territories	025 Yes ☐	125		165		
Nunavut	026 Yes ☐	126		166		
Outside Canada	027 Yes ☐	127		167		
Total		129 G		169 H		

Note 1: **Permanent establishment** is defined in subsection 400(2).
Note 2: For corporations other than those described under section 402, use the appropriate calculation described in the Regulations to allocate taxable income.

Notes:
1. After determining the allocation of taxable income, you have to calculate the corporation's provincial or territorial tax payable. For more information on how to calculate the tax for each province or territory, see the instructions for Schedule 5 in the T2 Corporation – Income Tax Guide.
2. If your corporation has provincial or territorial tax payable, complete Part 2.
3. If your corporation is a member of a partnership and the partnership had a permanent establishment in a jurisdiction, select the jurisdiction in Column A and include your proportionate share of the partnership's salaries and wages and gross revenue in columns B and D, respectively.

Part 2 – Ontario tax payable, tax credits, and rebates

Total taxable income	Income eligible for small business deduction	Provincial or territorial allocation of taxable income	Provincial or territorial tax payable before credits

	Line	Amount		Total	Ref
Ontario basic income tax (from Schedule 500)	270				
Ontario small business deduction (from Schedule 500)	402				
Subtotal (line 270 **minus** line 402)			▶		5A
Ontario transitional tax debits (from Schedule 506)	276				
Recapture of Ontario research and development tax credit (from Schedule 508)	277				
Subtotal (line 276 **plus** line 277)			▶		5B
Gross Ontario tax (amount 5A **plus** amount 5B)					5C
Ontario resource tax credit (from Schedule 504)	404				
Ontario tax credit for manufacturing and processing (from Schedule 502)	406				
Ontario foreign tax credit (from Schedule 21)	408				
Ontario credit union tax reduction (from Schedule 500)	410				
Ontario political contributions tax credit (from Schedule 525)	415				
Ontario non-refundable tax credits (total of lines 404 to 415)			▶		5D
Subtotal (amount 5C **minus** amount 5D) (if negative, enter "0")					5E
Ontario research and development tax credit (from Schedule 508)	416				
Ontario corporate income tax payable before Ontario corporate minimum tax credit and Ontario community food program donation tax credit for farmers (amount 5E **minus** line 416) (if negative, enter "0")					5F
Ontario corporate minimum tax credit (from Schedule 510)	418				
Ontario community food program donation tax credit for farmers (from Schedule 2)	420				
Ontario corporate income tax payable (amount 5F **minus** the total of lines 418 and 420) (if negative, enter "0")					5G
Ontario corporate minimum tax (from Schedule 510)	278	67,185			
Ontario special additional tax on life insurance corporations (from Schedule 512)	280				
Subtotal (line 278 **plus** line 280)		67,185	▶	67,185	5H
Total Ontario tax payable before refundable tax credits (amount 5G **plus** amount 5H)				67,185	5I
Ontario qualifying environmental trust tax credit	450				
Ontario co-operative education tax credit (from Schedule 550)	452				
Ontario apprenticeship training tax credit (from Schedule 552)	454				
Ontario computer animation and special effects tax credit (from Schedule 554)	456				
Ontario film and television tax credit (from Schedule 556)	458				
Ontario production services tax credit (from Schedule 558)	460				
Ontario interactive digital media tax credit (from Schedule 560)	462				
Ontario book publishing tax credit (from Schedule 564)	466				
Ontario innovation tax credit (from Schedule 566)	468				
Ontario business-research institute tax credit (from Schedule 568)	470				
Ontario regional opportunities investment tax credit (from Schedule 570)	472				
Ontario refundable tax credits (total of lines 450 to 472)			▶		5J
Net Ontario tax payable or refundable tax credit (amount 5I **minus** amount 5J) (if a credit, enter amount in brackets) Include this amount on line 255.	290			67,185	

Summary

Enter the total net tax payable or refundable tax credits for all provinces and territories on line 255.

Net provincial and territorial tax payable or refundable tax credits 255 67,185

If the amount on line 255 is positive, enter the net provincial and territorial tax payable on line 760 of the T2 return.
If the amount on line 255 is negative, enter the net provincial and territorial refundable tax credits on line 812 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 8

Capital Cost Allowance (CCA)

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

For more information, see the section called "Capital Cost Allowance" in the T2 Corporation Income Tax Guide.

Is the corporation electing under Regulation 1101(5q)? **101** Yes [ ] No [X]

	1 Class number * See note 1 **200**	Description	2 Undepreciated capital cost (UCC) at the beginning of the year **201**	3 Cost of acquisitions during the year (new property must be available for use) See note 2 **203**	4 Cost of acquisitions from column 3 that are accelerated investment incentive properties (AIIP) or zero-emission vehicle (ZEV) See note 3 **225**	5 Adjustments and transfers See note 4 **205**	6 Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition See note 5 **221**	7 Amount from column 5 that is repaid during the year for a property, subsequent to its disposition See note 6 **222**	8 Proceeds of dispositions See note 7 **207**	9 UCC (column 2 **plus** column 3 **plus** or **minus** column 5 **minus** column 8) See note 8
1.	1		19,627,626						0	19,627,626
2.	1	New Building	17,759,736						0	17,759,736
3.	1b	New Building Additions	382,972	584,705	584,705				0	967,677
4.	47		45,315,892	10,436,368	10,436,368	1,493,945			0	57,246,205
5.	14.1		1,872,531						0	1,872,531
6.	8	Smart Meters	744,990			-744,990			0	
		Totals	85,703,747	11,021,073	11,021,073	748,955				97,473,775

	1 Class number * See note 1 **200**	Description	10 Proceeds of disposition available to reduce the UCC of AIIP and ZEV (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP and ZEV acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP and ZEV acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for property acquired during the year other than AIIP and ZEV (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 **224**	14 CCA rate % See note 11 **212**	15 Recapture of CCA See note 12 **213**	16 Terminal loss See note 13 **215**	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 **217**	18 UCC at the end of the year (column 9 **minus** column 17) **220**
1.	1						4	0	0	785,105	18,842,521
2.	1	New Building					4	0	0	710,389	17,049,347
3.	1b	New Building Additions		584,705	292,353		6	0	0	75,602	892,075
4.	47			10,436,368	5,218,184		8	0	0	4,997,151	52,249,054
5.	14.1						5	0	0	131,078	1,741,453

	1 Class number * See note 1 200	Description	10 Proceeds of disposition available to reduce the UCC of AIIP and ZEV (column 8 **plus** column 6 **minus** column 3 **plus** column 4 **minus** column 7) (if negative, enter "0")	11 Net capital cost additions of AIIP and ZEV acquired during the year (column 4 **minus** column 10) (if negative, enter "0")	12 UCC adjustment for AIIP and ZEV acquired during the year (column 11 **multiplied** by the relevant factor) See note 9	13 UCC adjustment for property acquired during the year other than AIIP and ZEV (0.5 **multiplied** by the result of column 3 **minus** column 4 **minus** column 6 **plus** column 7 **minus** column 8) (if negative, enter "0") See note 10 224	14 CCA rate % See note 11 212	15 Recapture of CCA See note 12 213	16 Terminal loss See note 13 215	17 CCA (for declining balance method, the result of column 9 **plus** column 12 **minus** column 13, **multiplied** by column 14 or a lower amount) See note 14 217	18 UCC at the end of the year (column 9 **minus** column 17) 220
6.	8	Smart Meters					20	0	0		
		Totals		11,021,073	5,510,537					6,699,325	90,774,450

Enter the total of column 15 on line 107 of Schedule 1.
Enter the total of column 16 on line 404 of Schedule 1.
Enter the total of column 17 on line 403 of Schedule 1.

Note 1. If a class number has not been provided in Schedule II of the Income Tax Regulations for a particular class of property, use the subsection provided in Regulation 1101. Class numbers followed by a letter indicate the basic rate of the class taking into account the additional deduction allowed. Class 1a: 4% + 6% = 10% (class 1 to 10%), class 1b: 4% + 2% = 6% (class 1 to 6%).

Note 2. Include any property acquired in previous years that has now become available for use, net of any government assistance received or entitled to be received in the year from a government, municipality or other public authority, or a reduction of capital cost after the application of section 80. This property would have been previously excluded from column 3. List separately any acquisitions of property in the class that are not subject to the 50% rule. See Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance, for exceptions to the 50% rule.

Note 3. An AIIP is a property (other than ZEV) that you acquired after November 20, 2018 and became available for use before 2028. ZEV is, subject to certain exceptions, a motor vehicle included in Class 54 or 55 that you acquired after March 18, 2019 and became available for use before 2028. The Government proposes to create Class 56 for zero-emission automotive equipment and vehicles that currently do not benefit from the accelerated rate provided by Classes 54 and 55. Class 56 would apply to eligible zero-emission automotive equipment and vehicles that are acquired after March 1, 2020, and became available for use before 2028. Columns 4, 10, 11 and 12 also apply for additions of class 56 property. See the T2 Corporation Income Tax Guide for more information.

Note 4. Enter in column 5, "Adjustments and transfers", amounts that increase or reduce the UCC (column 9). Items that increase the UCC include amounts transferred under section 85, or transferred on amalgamation or winding-up of a subsidiary. Items that reduce the UCC (show amounts that reduce the UCC in brackets) include assistance received or receivable during the year for a property, subsequent to its disposition, if such assistance would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f). See the T2 Corporation Income Tax Guide for other examples of adjustments and transfers to include in column 5.
Also include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor at least 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 5. Include all amounts of assistance you received (or were entitled to receive) after the disposition of a depreciable property that would have decreased the capital cost of the property by virtue of paragraph 13(7.1)(f) if received before the disposition.

Note 6. Include all amounts you have repaid during the year with respect to any legally required repayment, made after the disposition of a corresponding property, of:

- assistance that would have otherwise increased the capital cost of the property under paragraph 13(7.1)(d) and
- an inducement, assistance or any other amount contemplated in paragraph 12(1)(x) received, that otherwise would have increased the capital cost of the property under paragraph 13(7.4)(b)

Include the UCC of each property of a prescribed class acquired in the course of a corporate reorganization described under paragraph 55(3)(b) of the Act (also known as "butterfly reorganization") or include property acquired in a non-arm's length transaction (other than by virtue of a right referred to in paragraph 251(5)(b) of the Act) if the property was a depreciable property acquired by the transferor less than 364 days before the end of your tax year and continuously owned by the transferor until it was acquired by you.

Note 7. For each property disposed of during the year, deduct from the proceeds of disposition any outlays and expenses to the extent that they were made or incurred for the purpose of making the disposition(s). The amount reported in respect of the property cannot exceed the property's capital cost, unless that property is a timber resource property as defined in subsection 13(21).
The proceeds of disposition of a ZEV that has been included in Class 54 and that is subject to the $55,000 (plus sales taxes) capital cost limit will be adjusted based on a factor equal to the capital cost limit of $55,000 (plus sales taxes) as a proportion of the actual cost of the vehicle.

Note 8. If the amount in column 5 reduces the undepreciated capital cost (i.e. it is shown in brackets), you must subtract it for the purposes of the calculation. Otherwise, add the amount in column 5 for the purposes of the calculation.

Note 9. The relevant factors for property of a class in Schedule II, that is AIIP or included in Classes 54 to 56, available for use before 2024 are:

- 2 1/3 for property in Classes 43.1, 54 and 56
- 1 1/2 for property in Class 55
- 1 for property in Classes 43.2 and 53
- 0 for property in Classes 12, 13, 14, and 15, as well as properties that are Canadian vessels included in paragraph 1100(1)(v) of the Regulations (see note 14 for additional information) and
- 0.5 for all other property that is AIIP

Note 10. The UCC adjustment for property acquired during the year other than AIIP and ZEV (formerly known as the half-year rule or 50% rule) does not apply to certain property (including AIIP). For special rules and exceptions, see Income Tax Folio S3-F4-C1, General Discussion of Capital Cost Allowance.

Note 11. Enter a rate only if you are using the declining balance method. For any other method (for example the straight-line method, where calculations are always based on the cost of acquisitions), enter N/A. Then enter the amount you are claiming in column 17.

Note 12. If the amount in column 9 is negative, you have a recapture of CCA. If applicable, enter the negative amount from column 9 in column 15 as a positive. The recapture rules do not apply to passenger vehicles in Class 10.1.

Note 13. If no property is left in the class at the end of the tax year and there is still a positive amount in the column 9, you have a terminal loss. If applicable, enter the positive amount from column 9 in column 16. The terminal loss rules do not apply to:

- passenger vehicles in Class 10.1
- property in Class 14.1, unless you have ceased carrying on the business to which it relates or
- limited-period franchises, concessions, or licences in Class 14 if, at the time of acquisition, the property was a former property of the transferor or any similar property attributable to the same fixed place of business, and you had jointly elected with the transferor to have the replacement property rules apply, unless certain conditions are met

Note 14. If the tax year is shorter than 365 days, prorate the CCA claim. Some classes of property do not have to be prorated. See the T2 Corporation Income Tax Guide for more information. For property in class 10.1 disposed of during the year, deduct a maximum of 50% of the regular CCA deduction if you owned the property at the beginning of the tax year. For AIIP listed below, the maximum first year allowance you can claim is determined as follows:

- Class 13: the lesser of 150% of the amount calculated in Schedule III of the Regulations and the UCC at the end of the tax year (before any CCA deduction)
- Class 14: the lesser of 150% of the allocation for the year of the capital cost of the property apportioned over the remaining life of the property (at the time the cost was incurred) and the UCC at the end of the tax year (before any CCA deduction)
- Class 15: the lesser of 150% of an amount computed on the basis of a rate per cord, board foot or cubic metre cut in the tax year and the UCC at the end of the tax year (before any CCA deduction)
- Canadian vessels described under paragraph 1100(1)(v) of the Regulations: the lesser of 50% of the capital cost of the property and the UCC at the end of the tax year (before any CCA deduction)
- Class 41.2: use a 25% CCA rate. The additional allowance under paragraph 1100(1)(y.2) (for single mine properties) and 1100(1)(ya.2) (for multiple mine properties) of the Regulations is not eligible for the accelerated investment incentive. The additional allowance in respect of natural gas liquefaction under paragraph 1100(1)(yb) of the Regulations is eligible for the accelerated investment incentive

The AIIP also apply to property (other than a timber resource property) that is a timber limit or a right to cut timber from a limit as well as to industrial mineral mine or a right to remove minerals from an industrial mineral mine. See the Income Tax Regulations for more detail.

Canada Revenue Agency | Agence du revenu du Canada

SCHEDULE 9

RELATED AND ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

- Complete this schedule if the corporation is related to or associated with at least one other corporation.
- For more information, see the *T2 Corporation Income Tax Guide*.

	Name 100	Country of residence (other than Canada) 200	Business number (see note 1) 300	Relationship code (see note 2) 400	Number of common shares you own 500	% of common shares you own 550	Number of preferred shares you own 600	% of preferred shares you own 650	Book value of capital stock 700
1.	PUC Inc		89839 7518 RC0001	1					
2.	PUC Services Inc		87626 3526 RC0002	3					

Note 1: Enter "NR" if the corporation is not registered or does not have a business number.
Note 2: Enter the code number of the relationship that applies from the following order: 1 - Parent 2 - Subsidiary 3 - Associated 4 - Related but not associated

T2 SCH 9 (11)

Canada

Continuity of financial statement reserves (not deductible)

Financial statement reserves (not deductible)

	Description	Balance at the beginning of the year	Transfer on an amalgamation or the wind-up of a subsidiary	Add	Deduct	Balance at the end of the year
1	AFDA	348,864		348,864	348,864	348,864
2						
	Reserves from Part 2 of Schedule 13					
	Totals	348,864		348,864	348,864	348,864

The total opening balance plus the total transfers should be entered on line 414 of Schedule 1 as a deduction.
The total closing balance should be entered on line 126 of Schedule 1 as an addition.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 23

Agreement Among Associated Canadian-Controlled Private Corporations to Allocate the Business Limit

- For use by a Canadian-controlled private corporation (CCPC) to identify all associated corporations and to assign a percentage for each associated corporation. This percentage will be used to allocate the business limit for the small business deduction. Information from this schedule will also be used to determine the date the balance of tax is due and to calculate the reduction to the business limit.
- An associated CCPC that has more than one tax year ending in a calendar year must file an agreement for each tax year ending in that calendar year.

Column 1: Enter the legal name of each of the corporations in the associated group, including those deemed to be associated under subsection 256(2) of the Income Tax Act.

Column 2: Provide the business number for each corporation (if a corporation is not registered, enter "NR").

Column 3: Enter the association code from the list below that applies to each corporation:

1 – Associated for purposes of allocating the business limit (unless association code 5 applies)

2 – CCPC that is a **third corporation** as referred to in subsection 256(2) and has filed Schedule 28, Election not to be Associated Through a Third Corporation

3 – Non-CCPC that is a **third corporation**

4 – Associated non-CCPC

5 – Associated CCPC to which association code 1 does not apply because a **third corporation** has filed Schedule 28

Column 4: Enter the business limit for the year of each corporation in the associated group. Enter "0" if the corporation has association code 2, 3 or 4 in column 3 (except if the corporation is a cooperative or a credit union eligible for the SBD and it has association code 4).

Column 5: Assign a percentage to allocate the business limit to each corporation that has association code 1 in column 3. The total of all percentages in column 5 cannot exceed 100%.

Column 6: Enter the business limit allocated to each corporation by multiplying the amount in column 4 by the percentage in column 5. Add all business limits allocated in column 6 and enter the total at line A.

Ensure that the total at line A does not exceed $500,000.

Allocating the business limit

Date filed (do not use this area) . . . . . . **025** Year Month Day

Enter the calendar year the agreement applies to . . . . . . **050** Year 2021

Is this an amended agreement for the above calendar year that is intended to replace an agreement previously filed by any of the associated corporations listed below? . . . . . . **075** ☐ Yes ☒ No

	1 Name of associated corporations **100**	2 Business number of associated corporations **200**	3 Association code **300**	4 Business limit for the year before the allocation $	5 Percentage of the business limit % **350**	6 Business limit allocated* $ **400**	
1	PUC Distribution Inc.	86709 6778 RC0001	1	500,000	100.0000	500,000	
2	PUC Inc	89839 7518 RC0001	1	500,000			
3	PUC Services Inc	87626 3526 RC0002	1	500,000			
				Total	100.0000	500,000	A

Business limit reduction under subsection 125(5.1) of the Act

The business limit reduction is calculated in the small business deduction area of the T2 return. One of the factors used in this calculation is the "large corporation amount" at line 415 of the T2 return. The amount at line 415 is determined using the formula 0.225% x (C - $10,000,000). Another factor is the "adjusted aggregate investment income" from lines 744 and 745 of Schedule 7, Aggregate Investment Income and Income Eligible for the Small Business Deduction. Details of these formulas and variable C are in subsection 125(5.1) of the Act.

* Each corporation will enter on line 410 of the T2 return, the amount allocated to it in column 6. However, if the corporation's tax year is less than 51 weeks, prorate the amount in column 6 by the number of days in the tax year divided by 365, and enter the result on line 410 of the T2 return.

Special rules for business limit

Special rules apply under subsection 125(5) if a CCPC has more than one tax year ending in the same calendar year and it is associated in more than one of those tax years with another CCPC that has a tax year ending in that calendar year. The business limit for the second or later tax year will be equal to the lesser of: the business limit determined for the first tax year ending in the calendar year or the business limit determined for the second or later tax year ending in the same calendar year.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 33

Taxable Capital Employed in Canada – Large Corporations

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

- Use this schedule in determining if the total taxable capital employed in Canada of the corporation (other than a financial institution or an insurance corporation) and its related corporations is greater than $10,000,000.
- If the total taxable capital employed in Canada of the corporation and its related corporations is greater than $10,000,000, file a completed Schedule 33 with your T2 *Corporation Income Tax Return* no later than six months from the end of the tax year.
- Unless otherwise noted, all legislative references are to the *Income Tax Act* and the *Income Tax Regulations*.
- Subsection 181(1) defines the terms **financial institution**, **long-term debt**, and **reserves**.
- Subsection 181(3) provides the basis to determine the carrying value of a corporation's assets or any other amount under Part I.3 for its capital, investment allowance, taxable capital, or taxable capital employed in Canada, or for a partnership in which it has an interest.
- If the corporation was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada, go to Part 4, **Taxable capital employed in Canada**.

Part 1 – Capital

Add the following year-end amounts:

Reserves that have not been deducted in calculating income for the year under Part I	101	348,864	
Capital stock (or members' contributions if incorporated without share capital)	103	20,062,107	
Retained earnings	104	18,618,415	
Contributed surplus	105		
Any other surpluses	106		
Deferred unrealized foreign exchange gains	107		
All loans and advances to the corporation	108	12,638,877	
All indebtedness of the corporation represented by bonds, debentures, notes, mortgages, hypothecary claims, bankers' acceptances, or similar obligations	109	68,079,765	
Any dividends declared but not paid by the corporation before the end of the year	110		
All other indebtedness of the corporation (other than any indebtedness for a lease) that has been outstanding for more than 365 days before the end of the year	111		
The total of all amounts, each of which is the amount, if any, in respect of a partnership in which the corporation held a membership interest at the end of the year, either directly or indirectly through another partnership (see note below)	112		
Subtotal (**add** lines 101 to 112)		119,748,028 ▶	119,748,028 A

Note:

Line 112 is determined by the formula (A – B) x C/D (as per paragraph 181.2(3)(g)) where:

A is the total of all amounts that would be determined for lines 101, 107, 108, 109, and 111 in respect of the partnership for its last fiscal period that ends at or before the end of the year if
- a) those lines applied to partnerships in the same manner that they apply to corporations, and
- b) those amounts were computed without reference to amounts owing by the partnership
  - (i) to any corporation that held a membership interest in the partnership either directly or indirectly through another partnership, or
  - (ii) to any partnership in which a corporation described in subparagraph (i) held a membership interest either directly or indirectly through another partnership.

B is the partnership's deferred unrealized foreign exchange losses at the end of the period,

C is the share of the partnership's income or loss for the period to which the corporation is entitled either directly or indirectly through another partnership, and

D is the partnership's income or loss for the period.

Part 1 – Capital (continued)

Subtotal A (from page 1)		119,748,028 A
Deduct the following amounts:		
Deferred tax debit balance at the end of the year	121	
Any deficit deducted in calculating its shareholders' equity (including, for this purpose, the amount of any provision for the redemption of preferred shares) at the end of the year	122	
To the extent that the amount may reasonably be regarded as being included in any of lines 101 to 112 above for the year, any amount deducted under subsection 135(1) in calculating income under Part I for the year.	123	
Deferred unrealized foreign exchange losses at the end of the year	124	
Subtotal (**add** lines 121 to 124) ▶		B
Capital for the year (amount A **minus** amount B) (if negative, enter "0")	190	119,748,028

Part 2 – Investment allowance

Add the carrying value at the end of the year of the following assets of the corporation:

A share of another corporation	401	
A loan or advance to another corporation (other than a financial institution)	402	
A bond, debenture, note, mortgage, hypothecary claim, or similar obligation of another corporation (other than a financial institution)	403	
Long-term debt of a financial institution	404	
A dividend payable on a share of the capital stock of another corporation	405	
A loan or advance to, or a bond, debenture, note, mortgage, hypothecary claim or similar obligation of, a partnership each member of which was, throughout the year, another corporation (other than a financial institution) that was not exempt from tax under this Part (otherwise than because of paragraph 181.1(3)(d)), or another partnership described in paragraph 181.2(4)(d.1)	406	
An interest in a partnership (see note 2 below)	407	
Investment allowance for the year (add lines 401 to 407)	490	

Notes:

1. Lines 401 to 405 should not include the carrying value of a share of the capital stock of, a dividend payable by, or indebtedness of a corporation that is exempt from tax under Part I.3 (other than a non-resident corporation that at no time in the year carried on business in Canada through a permanent establishment).
2. Where the corporation has an interest in a partnership held either directly or indirectly through another partnership, refer to subsection 181.2(5) for additional rules regarding the carrying value of an interest in a partnership.
3. Where a trust is used as a conduit for loaning money from a corporation to another related corporation (other than a financial institution), the loan will be considered to have been made directly from the lending corporation to the borrowing corporation. Refer to subsection 181.2(6) for special rules that may apply.

Part 3 – Taxable capital

Capital for the year (line 190)		119,748,028 C
Deduct: Investment allowance for the year (line 490)		D
Taxable capital for the year (amount C **minus** amount D) (if negative, enter "0")	500	119,748,028

Part 4 – Taxable capital employed in Canada

To be completed by a corporation that was resident in Canada at any time in the year

Taxable capital for the year (line 500) 119,748,028 x (Taxable income earned in Canada **610** 1,000 / Taxable income 1,000) = **Taxable capital employed in Canada** **690** 119,748,028

Notes:
1. Regulation 8601 gives details on calculating the amount of taxable income earned in Canada.
2. Where a corporation's taxable income for a tax year is "0," it shall, for the purposes of the above calculation, be deemed to have a taxable income for that year of $1,000.
3. In the case of an airline corporation, Regulation 8601 should be considered when completing the above calculation.

To be completed by a corporation that was a non-resident of Canada throughout the year and carried on a business through a permanent establishment in Canada

Total of all amounts each of which is the carrying value at the end of the year of an asset of the corporation used in the year or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . **701** ____________

Deduct the following amounts:

Corporation's indebtedness at the end of the year [other than indebtedness described in any of paragraphs 181.2(3)(c) to (f)] that may reasonably be regarded as relating to a business it carried on during the year through a permanent establishment in Canada . . . . **711** ____________

Total of all amounts each of which is the carrying value at the end of year of an asset described in subsection 181.2(4) of the corporation that it used in the year, or held in the year, in the course of carrying on any business during the year through a permanent establishment in Canada . . . . **712** ____________

Total of all amounts each of which is the carrying value at the end of year of an asset of the corporation that is a ship or aircraft the corporation operated in international traffic, or personal or movable property used or held by the corporation in carrying on any business during the year through a permanent establishment in Canada (see note below) . . . . **713** ____________

Total deductions (**add** lines 711, 712, and 713) ____________ ▶ ____________ E

Taxable capital employed in Canada (line 701 **minus** amount E) (if negative, enter “0“) . . . . **790** ____________

Note: Complete line 713 only if the country in which the corporation is resident did not impose a capital tax for the year on similar assets, or a tax for the year on the income from the operation of a ship or aircraft in international traffic, of any corporation resident in Canada during the year.

Part 5 – Calculation for purposes of the small business deduction

This part is applicable to corporations that are not associated in the current year, but were associated in the prior year.

Taxable capital employed in Canada (amount from line 690)		F
Deduct:	10,000,000	G
Excess (amount F **minus** amount G) (if negative, enter "0")		H
Calculation for purposes of the small business deduction (amount H x 0.225%)		I

Enter this amount at line 415 of the T2 return.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 50

Shareholder Information

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

- All private corporations must complete this schedule for any shareholder who holds 10% or more of the corporation's common and/or preferred shares.
- Provide only one number (business number, partnership account number, social insurance number or trust number) per shareholder.

	Name of shareholder (after name, indicate in brackets if the shareholder is a corporation, partnership, individual, or trust) 100	Business number or partnership account number (9 digits, 2 letters, and 4 digits. If not registered, enter "**NR**") 200	Social insurance number (9 digits) 300	Trust number (T followed by 8 digits) 350	Percentage common shares 400	Percentage preferred shares 500
1	PUC Inc	898397518RC0001			100.000	
2						
3						
4						
5						
6						
7						
8						
9						
10						

Canada Revenue Agency / Agence du revenu du Canada

Schedule 55

Part III.1 Tax on Excessive Eligible Dividend Designations

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

Do not use this area

- Every corporation resident in Canada that pays a taxable dividend (other than a capital gains dividend within the meaning assigned by subsection 130.1(4) or 131(1)) in the tax year must file this schedule.
- Canadian-controlled private corporations (CCPC) and deposit insurance corporations (DIC) must complete Part 1 of this schedule. All other corporations must complete Part 2.
- Every corporation that has paid an eligible dividend must also file Schedule 53, General Rate Income Pool (GRIP) Calculation, or Schedule 54, Low Rate Income Pool (LRIP) Calculation, whichever is applicable.
- File the schedules with your T2 Corporation Income Tax Return no later than six months from the end of the tax year.
- All legislative references are to the Income Tax Act and the Income Tax Regulations.
- Subsection 89(1) defines the terms **eligible dividend**, **excessive eligible dividend designation**, **general rate income pool**, and **low rate income pool**.
- The calculations in Part 1 and Part 2 do not apply if the excessive eligible dividend designation arises from the application of paragraph (c) of the definition of excessive eligible dividend designation in subsection 89(1). This paragraph applies when an eligible dividend is paid to artificially maintain or increase the GRIP or to artificially maintain or decrease the LRIP.

Part 1 – Canadian-controlled private corporations and deposit insurance corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3				
Total taxable dividends paid in the tax year	100			
Total eligible dividends paid in the tax year			150	
GRIP at the end of the tax year (line 590 on Schedule 53) (if negative, enter "0")			160	
Excessive eligible dividend designation (line 150 **minus** line 160)				A
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			180	
Subtotal (amount A **minus** line 180)				B
Part III.1 tax on excessive eligible dividend designations – CCPC or DIC (amount B **multiplied** by 20 %)			190	

Enter the amount from line 190 on line 710 of the T2 return.

Part 2 – Other corporations

Taxable dividends paid in the tax year **not included** in Schedule 3				
Taxable dividends paid in the tax year **included** in Schedule 3		610,080		
Total taxable dividends paid in the tax year	200	610,080		
Total excessive eligible dividend designations in the tax year (amount A of Schedule 54)				C
Excessive eligible dividend designations elected under subsection 185.1(2) to be treated as ordinary dividends *			280	
Subtotal (amount C **minus** line 280)				D
Part III.1 tax on excessive eligible dividend designations – Other corporations (amount D **multiplied** by 20 %)			290	

Enter the amount from line 290 on line 710 of the T2 return.

* You can elect to treat all or part of your excessive eligible dividend designation as a separate taxable dividend in order to eliminate or reduce the Part III.1 tax otherwise payable. You must file the election on or before the day that is 90 days **after** the day the notice of assessment for Part III.1 tax was sent. We will accept an election before the assessment of the tax.

Canada Revenue Agency / Agence du revenu du Canada

Schedule 510

Ontario Corporate Minimum Tax

Corporation's name	Business number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

- File this schedule if the corporation is subject to Ontario corporate minimum tax (CMT). CMT is levied under section 55 of the *Taxation Act, 2007* (Ontario), referred to as the "Ontario Act".
- Complete Part 1 to determine if the corporation is subject to CMT for the tax year.
- A corporation not subject to CMT in the tax year is still required to file this schedule if it is deducting a CMT credit, has a CMT credit carryforward, or has a CMT loss carryforward or a current year CMT loss.
- A corporation that has Ontario special additional tax on life insurance corporations (SAT) payable in the tax year must complete Part 4 of this schedule even if it is not subject to CMT for the tax year.
- A corporation is exempt from CMT if, throughout the tax year, it was one of the following:
  1) a corporation exempt from income tax under section 149 of the federal *Income Tax Act*;
  2) a mortgage investment corporation under subsection 130.1(6) of the federal Act;
  3) a deposit insurance corporation under subsection 137.1(5) of the federal Act;
  4) a congregation or business agency to which section 143 of the federal Act applies;
  5) an investment corporation as referred to in subsection 130(3) of the federal Act; or
  6) a mutual fund corporation under subsection 131(8) of the federal Act.
- File this schedule with the *T2 Corporation Income Tax Return*.

Part 1 – Determination of CMT applicability

Total assets of the corporation at the end of the tax year *	112	142,184,900
Share of total assets from partnership(s) and joint venture(s) *	114	
Total assets of associated corporations (amount from line 450 on Schedule 511)	116	104,323,807
Total assets (total of lines 112 to 116)		246,508,707
Total revenue of the corporation for the tax year **	142	98,256,261
Share of total revenue from partnership(s) and joint venture(s) **	144	
Total revenue of associated corporations (amount from line 550 on Schedule 511)	146	25,336,286
Total revenue (total of lines 142 to 146)		123,592,547

The corporation is subject to CMT if:
- for tax years ending before July 1, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are more than $5,000,000, or the total revenue for the year of the corporation or the associated group of corporations is more than $10,000,000.
- for tax years ending after June 30, 2010, the total assets at the end of the year of the corporation or the associated group of corporations are equal to or more than $50,000,000, and the total revenue for the year of the corporation or the associated group of corporations is equal to or more than $100,000,000.

If the corporation is not subject to CMT, do not complete the remaining parts unless the corporation is deducting a CMT credit, or has a CMT credit carryforward, a CMT loss carryforward, a current year CMT loss, or SAT payable in the year.

* **Rules for total assets**
- Report total assets according to generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- Do not include unrealized gains and losses on assets and foreign currency gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.
- The amount on line 114 is determined at the end of the last fiscal period of the partnership or joint venture that ends in the tax year of the corporation. Add the proportionate share of the assets of the partnership(s) and joint venture(s), and deduct the recorded asset(s) for the investment in partnerships and joint ventures.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

** **Rules for total revenue**
- Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
- If the tax year is less than 51 weeks, **multiply** the total revenue of the corporation or the partnership, whichever applies, by 365 and **divide** by the number of days in the tax year.
- The amount on line 144 is determined for the partnership or joint venture fiscal period that ends in the tax year of the corporation. If the partnership or joint venture has 2 or more fiscal periods ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.
- A corporation's share in a partnership or joint venture is determined under paragraph 54(5)(b) of the Ontario Act and, if the partnership or joint venture had no income or loss, is calculated as if the partnership's or joint venture's income were $1 million. For a corporation with an indirect interest in a partnership or joint venture, determine the corporation's share according to paragraph 54(5)(c) of the Ontario Act.

Part 2 – Adjusted net income/loss for CMT purposes

Net income/loss per financial statements *			210	2,417,255
Add (to the extent reflected in income/loss):				
Provision for current income taxes/cost of current income taxes	220	71,089		
Provision for deferred income taxes (debits)/cost of future income taxes	222	602,000		
Equity losses from corporations	224			
Financial statement loss from partnerships and joint ventures	226			
Dividends deducted on financial statements (subsection 57(2) of the Ontario Act), excluding dividends paid by credit unions under subsection 137(4.1) of the federal Act	230			
Other additions (see note below):				
Share of adjusted net income of partnerships and joint ventures **	228			
Total patronage dividends received, not already included in net income/loss	232			
281	282			
283	284			
Subtotal		673,089 ▶		673,089 A
Deduct (to the extent reflected in income/loss):				
Provision for recovery of current income taxes/benefit of current income taxes	320			
Provision for deferred income taxes (credits)/benefit of future income taxes	322			
Equity income from corporations	324			
Financial statement income from partnerships and joint ventures	326			
Dividends deductible under section 112, section 113, or subsection 138(6) of the federal Act	330			
Dividends not taxable under section 83 of the federal Act (from Schedule 3)	332			
Gain on donation of listed security or ecological gift	340			
Accounting gain on transfer of property to a corporation under section 85 or 85.1 of the federal Act ***	342			
Accounting gain on transfer of property to/from a partnership under section 85 or 97 of the federal Act ****	344			
Accounting gain on disposition of property under subsection 13(4), subsection 14(6), or section 44 of the federal Act *****	346			
Accounting gain on a windup under subsection 88(1) of the federal Act or an amalgamation under section 87 of the federal Act	348			
Other deductions (see note below):				
Share of adjusted net loss of partnerships and joint ventures **	328			
Tax payable on dividends under subsection 191.1(1) of the federal Act **multiplied** by 3	334			
Interest deducted/deductible under paragraph 20(1)(c) or (d) of the federal Act, not already included in net income/loss	336			
Patronage dividends paid (from Schedule 16) not already included in net income/loss	338			
381 Tax on regulatory	382	602,000		
383	384			
385	386			
387	388			
389	390			
Subtotal		602,000 ▶		602,000 B
Adjusted net income/loss for CMT purposes (line 210 **plus** amount A **minus** amount B)			490	2,488,344

If the amount on line 490 is positive and the corporation is subject to CMT as determined in Part 1, enter the amount on line 515 in Part 3.

If the amount on line 490 is negative, enter the amount on line 760 in Part 7 (enter as a positive amount).

Note

In accordance with *Ontario Regulation 37/09*, when calculating net income for CMT purposes, accounting income should be adjusted to:

- exclude unrealized gains and losses due to mark-to-market changes or foreign currency changes on specified mark-to-market property (assets only);
- include realized gains and losses on the disposition of specified mark-to-market property not already included in the accounting income, if the property is not a capital property or is a capital property disposed in the year or in a previous tax year ended after March 22, 2007.

"Specified mark-to-market property" is defined in subsection 54(1) of the Ontario Act.

These rules also apply to partnerships. A corporate partner's share of a partnership's adjusted income flows through on a proportionate basis to the corporate partner.

* **Rules for net income/loss**

- Banks must report net income/loss as per the report accepted by the Superintendent of Financial Institutions under the federal *Bank Act*, adjusted so consolidation and equity methods are not used.

Part 2 – Calculation of adjusted net income/loss for CMT purposes (continued)

– Life insurance corporations must report net income/loss as per the report accepted by the federal Superintendent of Financial Institutions or equivalent provincial insurance regulator, before SAT and adjusted so consolidation and equity methods are not used. If the life insurance corporation is resident in Canada and carries on business in and outside of Canada, **multiply** the net income/loss by the ratio of the Canadian reserve liabilities **divided** by the total reserve liability. The reserve liabilities are calculated in accordance with Regulation 2405(3) of the federal Act.

– Other corporations must report net income/loss in accordance with generally accepted accounting principles, except that consolidation and equity methods must not be used. When the equity method has been used for accounting purposes, equity losses and equity income are removed from book income/loss on lines 224 and 324 respectively.

– Corporations, other than insurance corporations, should report net income from line 9999 of the GIFI (Schedule 125) on line 210.

** The share of the adjusted net income of a partnership or joint venture is calculated as if the partnership or joint venture were a corporation and the tax year of the partnership or joint venture were its fiscal period. For a corporation with an indirect interest in a partnership through one or more partnerships, determine the corporation's share according to clause 54(5)(c) of the Ontario Act.

*** A joint election will be considered made under subsection 60(1) of the Ontario Act if there is an entry on line 342, and an election has been made for transfer of property to a corporation under subsection 85(1) of the federal Act.

**** A joint election will be considered made under subsection 60(2) of the Ontario Act if there is an entry on line 344, and an election has been made under subsection 85(2) or 97(2) of the federal Act.

***** A joint election will be considered made under subsection 61(1) of the Ontario Act if there is an entry on line 346, and an election has been made under subsection 13(4) or 14(6) and/or section 44 of the federal Act.

For more information on how to complete this part, see the *T2 Corporation – Income Tax Guide*.

Part 3 – CMT payable

Adjusted net income for CMT purposes (line 490 in Part 2, if positive)	515	2,488,344	
Deduct:			
CMT loss available (amount R from Part 7)			
Minus: Adjustment for an acquisition of control *	518		
Adjusted CMT loss available	▶		C
Net income subject to CMT calculation (if negative, enter "0")	520	2,488,344	

Amount from line 520	2,488,344	x	Number of days in the tax year before July 1, 2010 / Number of days in the tax year	/ 365	x 4 % =		1
Amount from line 520	2,488,344	x	Number of days in the tax year after June 30, 2010 / Number of days in the tax year	365 / 365	x 2.7 % =	67,185	2
			Subtotal (amount 1 **plus** amount 2)			67,185	3

Gross CMT: amount on line 3 above x OAF **	540	67,185	
Deduct:			
Foreign tax credit for CMT purposes ***	550		
CMT after foreign tax credit deduction (line 540 **minus** line 550) (if negative, enter "0")		67,185	D
Deduct:			
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)			
Net CMT payable (if negative, enter "0")		67,185	E

Enter amount E on line 278 of Schedule 5, *Tax Calculation Supplementary – Corporations*, and complete Part 4.

* Enter the portion of CMT loss available that exceeds the adjusted net income for the tax year from carrying on a business before the acquisition of control. See subsection 58(3) of the Ontario Act.

*** Enter "0" on line 550 for life insurance corporations as they are not eligible for this deduction. For all other corporations, enter the cumulative total of amount J for the province of Ontario from Part 9 of Schedule 21 on line 550.

** **Calculation of the Ontario allocation factor (OAF):**

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "Ontario," enter "1" on line F.

If the provincial or territorial jurisdiction entered on line 750 of the T2 return is "multiple," complete the following calculation, and enter the result on line F:

Ontario taxable income **** / Taxable income ***** ______ = ______

Ontario allocation factor 1.00000 F

**** Enter the amount allocated to Ontario from column F in Part 1 of Schedule 5. If the taxable income is nil, calculate the amount in column F as if the taxable income were $1,000.

***** Enter the taxable income amount from line 360 or amount Z of the T2 return, whichever applies. If the taxable income is nil, enter "1,000".

Part 4 – Calculation of CMT credit carryforward

CMT credit carryforward at the end of the previous tax year *		366,350	G		
Deduct:					
CMT credit expired *	600				
CMT credit carryforward at the beginning of the current tax year * (see note below)		366,350	▶ 620	366,350	
Add:					
CMT credit carryforward balances transferred on an amalgamation or the windup of a subsidiary (see note below)			650		
CMT credit available for the tax year (amount on line 620 **plus** amount on line 650)				366,350	H
Deduct:					
CMT credit deducted in the current tax year (amount P from Part 5)					I
Subtotal (amount H **minus** amount I)				366,350	J
Add:					
Net CMT payable (amount E from Part 3)		67,185			
SAT payable (amount O from Part 6 of Schedule 512)					
Subtotal		67,185	▶	67,185	K
CMT credit carryforward at the end of the tax year (amount J **plus** amount K)			670	433,535	L

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line G or line 600;
- for line 620, enter the amount from line 2336 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line G the amount from line 670 of Schedule 510 from the previous tax year.

Note: If you entered an amount on line 620 or line 650, complete Part 6.

Part 5 – Calculation of CMT credit deducted from Ontario corporate income tax payable

CMT credit available for the tax year (amount H from Part 4)					366,350	M
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)				1		
For a corporation that is not a life insurance corporation:						
CMT after foreign tax credit deduction (amount D from Part 3)	67,185	2				
For a life insurance corporation:						
Gross CMT (line 540 from Part 3)		3				
Gross SAT (line 460 from Part 6 of Schedule 512)		4				
The **greater** of amounts 3 and 4		5				
Deduct: line 2 or line 5, whichever applies:			67,185	6		
Subtotal (if negative, enter "0")				▶		N
Ontario corporate income tax payable before CMT credit (amount F6 from Schedule 5)						
Deduct:						
Total refundable tax credits excluding Ontario qualifying environmental trust tax credit (amount J6 **minus** line 450 from Schedule 5)						
Subtotal (if negative, enter "0")				▶		O
CMT credit deducted in the current tax year (least of amounts M, N, and O)						P

Enter amount P on line 418 of Schedule 5 and on line I in Part 4 of this schedule.

Is the corporation claiming a CMT credit earned before an acquisition of control? 675 1 Yes ☐ 2 No ☒

If you answered **yes** to the question at line 675, the CMT credit deducted in the current tax year may be restricted. For information on how the deduction may be restricted, see subsections 53(6) and (7) of the Ontario Act.

Part 6 – Analysis of CMT credit available for carryforward by year of origin

Complete this part if:
- the tax year includes January 1, 2009; or
- the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	CMT credit balance *
10th previous tax year	680
9th previous tax year	681
8th previous tax year	682
7th previous tax year	683
6th previous tax year	684
5th previous tax year	685
4th previous tax year	686
3rd previous tax year	687
2nd previous tax year	688
1st previous tax year	689
Total **	

* CMT credit that was earned (by the corporation, predecessors of the corporation, and subsidiaries wound up into the corporation) in each of the previous 10 tax years and has not been deducted.

** Must equal the total of the amounts entered on lines 620 and 650 in Part 4.

Part 7 – Calculation of CMT loss carryforward

CMT loss carryforward at the end of the previous tax year * . . . . Q

Deduct:

CMT loss expired * 700

CMT loss carryforward at the beginning of the tax year * (see note below) . . . . ▶ 720

Add:

CMT loss transferred on an amalgamation under section 87 of the federal Act ** (see note below) 750

CMT loss available (line 720 **plus** line 750) . . . . R

Deduct:

CMT loss deducted against adjusted net income for the tax year (lesser of line 490 (if positive) and line C in Part 3) . . . .

Subtotal (if negative, enter "0") S

Add:

Adjusted net loss for CMT purposes (amount from line 490 in Part 2, if **negative**) (enter as a positive amount) 760

CMT loss carryforward balance at the end of the tax year (amount S **plus** line 760) . . . . 770 T

* For the first harmonized T2 return filed with a tax year that includes days in 2009:
- do not enter an amount on line Q or line 700;
- for line 720, enter the amount from line 2214 of Ontario CT23 Schedule 101, *Corporate Minimum Tax (CMT)*, for the last tax year that ended in 2008.

For other tax years, enter on line Q the amount from line 770 of Schedule 510 from the previous tax year.

** Do not include an amount from a predecessor corporation if it was controlled at any time before the amalgamation by any of the other predecessor corporations.

Note: If you entered an amount on line 720 or line 750, complete Part 8.

Part 8 – Analysis of CMT loss available for carryforward by year of origin

Complete this part if:

– the tax year includes January 1, 2009; or
– the previous tax year-end is deemed to be December 31, 2008, under subsection 249(3) of the federal Act.

Year of origin	Balance earned in a tax year ending before March 23, 2007 *	Balance earned in a tax year ending after March 22, 2007 **
10th previous tax year	810	820
9th previous tax year	811	821
8th previous tax year	812	822
7th previous tax year	813	823
6th previous tax year	814	824
5th previous tax year	815	825
4th previous tax year	816	826
3rd previous tax year	817	827
2nd previous tax year	818	828
1st previous tax year		829
Total ***		

* Adjusted net loss for CMT purposes that was earned (by the corporation, by subsidiaries wound up into or amalgamated with the corporation before March 22, 2007, and by other predecessors of the corporation) in each of the previous 10 tax years that ended before March 23, 2007, and has not been deducted.

** Adjusted net loss for CMT purposes that was earned (by the corporation and its predecessors, but not by a subsidiary predecessor) in each of the previous 20 tax years that ended after March 22, 2007, and has not been deducted.

*** The total of these two columns must equal the total of the amounts entered on lines 720 and 750.

Canada Revenue Agency / Agence du revenu du Canada

SCHEDULE 511

ONTARIO CORPORATE MINIMUM TAX – TOTAL ASSETS AND REVENUE FOR ASSOCIATED CORPORATIONS

Name of corporation	Business Number	Tax year-end Year Month Day
PUC Distribution Inc.	86709 6778 RC0001	2021-12-31

- For use by corporations to report the total assets and total revenue of all the Canadian or foreign corporations with which the filing corporation was associated at any time during the tax year. These amounts are required to determine if the filing corporation is subject to corporate minimum tax.
- Total assets and total revenue include the associated corporation's share of any partnership(s)/joint venture(s) total assets and total revenue.
- Attach additional schedules if more space is required.
- File this schedule with the *T2 Corporation Income Tax Return*.

	Names of associated corporations 200	Business number (Canadian corporation only) (see Note 1) 300	Total assets* (see Note 2) 400	Total revenue** (see Note 2) 500
1	PUC Inc	89839 7518 RC0001	62,636,738	2,967,099
2	PUC Services Inc	87626 3526 RC0002	41,687,069	22,369,187
		Total	450 104,323,807	550 25,336,286

Enter the total assets from line 450 on line 116 in Part 1 of Schedule 510, *Ontario Corporate Minimum Tax*.
Enter the total revenue from line 550 on line 146 in Part 1 of Schedule 510.

Note 1: Enter ¨NR¨ if a corporation is not registered.

Note 2: If the associated corporation does not have a tax year that ends in the filing corporation's current tax year but was associated with the filing corporation in the previous tax year of the filing corporation, enter the total revenue and total assets from the tax year of the associated corporation that ends in the previous tax year of the filing corporation.

* **Rules for total assets**

– Report total assets in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– Include the associated corporation's share of the total assets of partnership(s) and joint venture(s) but exclude the recorded asset(s) for the investment in partnerships and joint ventures.
– Exclude unrealized gains and losses on assets that are included in net income for accounting purposes but not in income for corporate income tax purposes.

** **Rules for total revenue**

– Report total revenue in accordance with generally accepted accounting principles, adjusted so that consolidation and equity methods are not used.
– If the associated corporation has 2 or more tax years ending in the filing corporation's tax year, **multiply** the sum of the total revenue for each of those tax years by 365 and **divide** by the total number of days in all of those tax years.
– If the associated corporation's tax year is less than 51 weeks and is the only tax year of the associated corporation that ends in the filing corporation's tax year, **multiply** the associated corporation's total revenue by 365 and **divide** by the number of days in the associated corporation's tax year.
– Include the associated corporation's share of the total revenue of partnerships and joint ventures.
– If the partnership or joint venture has 2 or more fiscal periods ending in the associated corporation's tax year, **multiply** the sum of the total revenue for each of the fiscal periods by 365 and **divide** by the total number of days in all the fiscal periods.

APPENDIX C
2023 Test Year
Income Tax (PILS)

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Version 1.00

Utility Name	PUC Distribution Inc.
Assigned EB Number	EB-2022-0059
Name and Title	Tyler Kasubeck, Regulatory Financial Analyst
Phone Number	705-759-6500
Email Address	tyler.kasubeck@ssmpuc.com
Date	31-Aug-22
Last COS Re-based Year	**2018**

Ontario Energy Board

Income Tax/PILs Workform for 2023 File

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

No inputs required on this worksheet.

Inputs on Service Revenue Requirement Worksheet

The Service Revenue Requirement is in the 'Revenue Requirement Workform' - Tab 3.

Item	Working Paper Reference		
Adjustments required to arrive at taxable income	as below	**-3,121,700**	
Test Year - Payments in Lieu of Taxes (PILs)	T0	**421,994**	
Test Year - Grossed-up PILs	T0	**574,141**	
Effective Federal Tax Rate	T0	**15.0%**	
Effective Ontario Tax Rate	T0	**11.5%**	
Calculation of Adjustments required to arrive at Taxable Income			
Regulatory Income (before income taxes)	T1	4,714,129	
Taxable Income	T1	1,592,430	
Difference	calculated	-3,121,700	as above

Income Tax/PILs Workform for 2023 Filers

Integrity Checks

The applicant must ensure the following integrity checks have been completed and confirm this is the case in the table below, or provide an explanation if this is not the case:

	Item	Utility Confirmation (Y/N)	Notes
1	The depreciation and amortization added back in the application's PILs model agree with the numbers disclosed in the rate base section of the application	Y	
2	The capital additions and deductions in the CCA Schedule 8 agree with the rate base section for historical, bridge and test years	Y	
3	Schedule 8 of the most recent federal T2 tax return filed with the application has a closing December 31 historical year UCC that agrees with the opening (January 1) bridge year UCC. If the amounts do not agree, then the applicant must provide a reconciliation with explanations. Distributors must segregate non-distribution tax amounts on Schedule 8.	Y	
4	The CCA deductions in the application's PILs tax model for historical, bridge and test years (as applicable) agree with the numbers in the CCA Schedule 8 for the same years filed in the application	Y	
5	Loss carry-forwards, if any, from prior year tax returns' Schedule 4 agree with those disclosed in the application	Y	
6	A discussion is included in the application as to when the loss carry-forwards, if any, will be fully utilized	Y	
7	CCA is maximized even if there are tax loss carry-forwards	Y	
8	Other post-employment benefits and pension expenses that are added back on Schedule 1 to reconcile accounting income to net income for tax purposes agree with the OM&A analysis for compensation. The amounts deducted are reasonable when compared with the notes to the audited financial statements, Financial Services Commission of Ontario reports, and actuarial valuations.	Y	
9	The income tax rate used to calculate the tax expense is consistent with the utility's actual tax facts and evidence filed in the application	Y	

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

			Test Year	Bridge Year	
Rate Base		S	**$ 136,089,187**	**$ 118,202,229**	

Return on Ratebase

Deemed ShortTerm Debt %	4.00%	T	$ 5,443,567	*W = S * T*	
Deemed Long Term Debt %	56.00%	U	$ 76,209,945	*X = S * U*	
Deemed Equity %	40.00%	V	$ 54,435,675	*Y = S * V*	
Short Term Interest Rate	1.17%	Z	$ 63,690	*AC = W * Z*	
Long Term Interest	3.97%	AA	$ 3,025,535	*AD = X * AA*	
Return on Equity (Regulatory Income)	8.66%	AB	**$ 4,714,129**	*AE = Y * AB*	T1
Return on Rate Base			**$ 7,803,354**	*AF = AC + AD + AE*	

Questions that must be answered

	Historical Year	Bridge Year	Test Year
1. Does the applicant have any Investment Tax Credits (ITC)?	No	No	No
2. Does the applicant have any SRED Expenditures?	No	No	No
3. Does the applicant have any Capital Gains or Losses for tax purposes?	No	No	No
4. Does the applicant have any Capital Leases?	No	No	No
5. Does the applicant have any Loss Carry-Forwards (non-capital or net capital)?	Yes	Yes	Yes
6. Since 1999, has the applicant acquired another regulated applicant's assets?	No	No	No
7. Did the applicant pay dividends? *If Yes, please describe the tax treatment in the manager's summary.*	Yes	Yes	Yes
8. Did the applicant elect to capitalize interest incurred on CWIP for tax purposes?	Yes	Yes	Yes

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Tax Rates **Federal & Provincial** **As of MMM XX, 2019**	**Effective January 1, 2016**	**Effective January 1, 2017**	**Effective January 1, 2018**	**Effective January 1, 2019**	**Effective January 1, 2020**	**Effective January 1, 2021**	**Effective January 1, 2022**
Federal income tax							
General Corporate Rate	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%	38.00%
Federal Tax Abatement	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%	-10.00%
Adjusted Federal Rate	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%	28.00%
Rate Reduction	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%	-13.00%
Federal Income Tax	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%	15.00%
Ontario Income Tax	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%	11.50%
Combined Federal and Ontario	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%	26.50%
Federal & Ontario Small Business							
Federal Small Business Limit	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Ontario Small Business Limit	500,000	500,000	500,000	500,000	500,000	500,000	500,000
Federal Small Business Rate	11.00%	10.50%	10.50%	10.00%	9.00%	9.00%	9.00%
Ontario Small Business Rate	4.50%	4.50%	3.50%	3.50%	3.20%	3.20%	3.20%

Income Tax/PILs Workform for 2023 Filers

PILs Tax Provision - Historical Year

Note: Input the actual information from the tax returns for the historical year.

				Wires Only	
Regulatory Taxable Income			H1	-$ 432,110	A
Combined Tax Rate and PILs	Ontario Tax Rate (Maximum 11.5%)	11.50%	B		
	Federal tax rate (Maximum 15%)	15.00%	C		
	Combined tax rate (Maximum 26.5%)			26.50%	D = B+C
Total Income Taxes				**-$ 114,509**	E = A * D
Investment Tax Credits					F
Miscellaneous Tax Credits					G
Total Tax Credits				**$ -**	H = F + G
Corporate PILs/Income Tax Provision for Historical Year				**$ -**	I = E - H

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Adjusted Taxable Income - Historical Year

	T2S1 line #	Total for Legal Entity	Non-Distribution Eliminations	Historic Wires Only
Income before PILs/Taxes	**(A + 101 + 102)**	3,090,344		3,090,344
Additions:				
Interest and penalties on taxes	103			0
Amortization of tangible assets	104	3,842,226		3,842,226
Amortization of intangible assets	106			0
Recapture of capital cost allowance from Schedule 8	107			0
Income inclusion under subparagraph 13(38)(d)(iii) from Schedule 10	108			0
Loss in equity of subsidiaries and affiliates	110			0
Loss on disposal of assets	111			0
Charitable donations and gifts from Schedule 2	112			0
Taxable capital gains from Schedule 6	113			0
Political contributions	114			0
Deferred and prepaid expenses	116			0
Scientific research expenditures deducted on financial statements	118			0
Capitalized interest	119			0
Non-deductible club dues and fees	120			0
Non-deductible meals and entertainment expense	121	1,623		1,623
Non-deductible automobile expenses	122			0
Non-deductible life insurance premiums	123			0
Non-deductible company pension plans	124			0
Tax reserves deducted in prior year	125			0
Reserves from financial statements – balance at the end of the year	126	348,864		348,864
Soft costs on construction and renovation of buildings	127			0
Capital items expensed	206			0
Debt issue expense	208			0
Development expenses claimed in current year	212			0
Financing fees deducted in books	216			0
Gain on settlement of debt	220			0
Non-deductible advertising	226			0
Non-deductible interest	227			0
Non-deductible legal and accounting fees	228			0
Recapture of SR&ED expenditures	231			0
Share issue expense	235			0
Write down of capital property	236			0
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237			0
Other additions				
Interest Expensed on Capital Leases	295			0
Realized Income from Deferred Credit Accounts	295			0
Pensions	295			0
Non-deductible penalties	295			0
	295			0
	295			0
ARO Accretion expense				0
Capital Contributions Received (ITA 12(1)(x))		3,674,486		3,674,486
Lease Inducements Received (ITA 12(1)(x))				0
Deferred Revenue (ITA 12(1)(a))				0
Prior Year Investment Tax Credits received				0
Sub 16 Depreciation - Charged To Regulatory		75,251		75,251
				0
				0
				0
				0
				0
				0
				0
				0
				0
Total Additions		**7,942,450**	**0**	**7,942,450**

Deductions:				
Gain on disposal of assets per financial statements	401			0
Non-taxable dividends under section 83	402			0
Capital cost allowance from Schedule 8	403	6,699,325		6,699,325
Terminal loss from Schedule 8	404			0
Allowable business investment loss	406			0
Deferred and prepaid expenses	409			0
Scientific research expenses claimed in year	411			0
Tax reserves claimed in current year	413			0
Reserves from financial statements - balance at beginning of year	414	348,864		348,864
Contributions to deferred income plans	416			0
Book income of joint venture or partnership	305			0
Equity in income from subsidiary or affiliates	306			0
Other deductions				
Interest capitalized for accounting deducted for tax	395			0
Capital Lease Payments	395			0
Non-taxable imputed interest income on deferral and variance accounts	395			0
Amortization of Contributed Capital	395	140,229		140,229
Regulatory Charges for Account Purposes	395	284,569		284,569
ARO Payments - Deductible for Tax when Paid				0
ITA 13(7.4) Election - Capital Contributions Received		3,674,486		3,674,486
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds				0
Deferred Revenue - ITA 20(1)(m) reserve				0
Principal portion of lease payments				0
Lease Inducement Book Amortization credit to income				0
Financing fees for tax ITA 20(1)(e) and (e.1)				0
				0
Non Taxable/deductible other comprehensive income items		317,431		317,431
				0
				0
				0
				0
				0
				0
Total Deductions		**11,464,904**	**0**	**11,464,904**
Net Income for Tax Purposes		**-432,110**	**0**	**-432,110**
Charitable donations from Schedule 2	311			0
Taxable dividends received under section 112 or 113	320			0
Non-capital losses of previous tax years from Schedule 4	331			0
Net capital losses of previous tax years from Schedule 4	332			0
Limited partnership losses of previous tax years from Schedule 4	335			0
TAXABLE INCOME		**-432,110**	**0**	**-432,110**

H0

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 4 Loss Carry Forward - Historical

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical	1,999,056		1,999,056	B4

Net Capital Loss Carry Forward Deduction	Total	Non-Distribution Portion	Utility Balance	
Actual Historical			0	B4

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 8 - Historical Year

Class	Class Description	UCC End of Year Historical per tax returns	Less: Non-Distribution Portion	UCC Regulated Historical Year	Working Paper Reference
1	Buildings, Distribution System (acq'd post 1987)	$ 35,891,868		$ 35,891,868	B8
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	$ 892,076		$ 892,076	B8
2	Distribution System (acq'd pre 1988)			$ -	B8
3	Buildings (acq'd pre 1988)			$ -	B8
6	Certain Buildings; Fences			$ -	B8
8	General Office Equipment, Furniture, Fixtures			$ -	B8
10	Motor Vehicles, Fleet			$ -	B8
10.1	Certain Automobiles			$ -	B8
12	Computer Application Software (Non-Systems)			$ -	B8
13_1	Lease # 1			$ -	B8
13_2	Lease # 2			$ -	B8
13_3	Lease # 3			$ -	B8
13_4	Lease # 4			$ -	B8
14	Limited Period Patents, Franchises, Concessions or Licences			$ -	B8
14.1	Eligible Capital Property (acq'd pre 2017)	$ 1,741,453		$ 1,741,453	B8
14.1	Eligible Capital Property (acq'd post 2016)			$ -	B8
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage			$ -	B8
42	Fibre Optic Cable			$ -	B8
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -	B8
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment			$ -	B8
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)			$ -	B8
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)			$ -	B8
47	Distribution System (acq'd post Feb 22/05)	$ 52,249,054		$ 52,249,054	B8
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)			$ -	B8
95	CWIP			$ -	B8
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
				$ -	
	SUB-TOTAL - UCC	90,774,451	0	90,774,451	

Only if election under ONTARIO REGULATION 162/01 ss. 5 or 7 filed in 2001 to have ITR 1102(14) apply

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 13 Tax Reserves - Historical

Continuity of Reserves

Description	Historical Balance as per tax returns	Non-Distribution Eliminations	Utility Only	
Capital gains reserves ss.40(1)			0	B13
Tax reserves not deducted for accounting purposes				
Reserve for doubtful accounts ss. 20(1)(l)	348,864		348,864	B13
Reserve for undelivered goods and services not rendered ss. 20(1)(m)			0	B13
Reserve for unpaid amounts ss. 20(1)(n)			0	B13
Debt & share issue expenses ss. 20(1)(e)			0	B13
Other tax reserves			0	B13
			0	
			0	
			0	
			0	
			0	
Total	**348,864**	**0**	**348,864**	
Financial Statement Reserves (not deductible for Tax Purposes)				
General reserve for inventory obsolescence (non-specific)			0	B13
General reserve for bad debts	348,864		348,864	B13
Accrued Employee Future Benefits:			0	B13
- Medical and Life Insurance			0	B13
-Short & Long-term Disability			0	B13
-Accmulated Sick Leave			0	B13
- Termination Cost			0	B13
- Other Post-Employment Benefits			0	B13
Provision for Environmental Costs			0	B13
Restructuring Costs			0	B13
Accrued Contingent Litigation Costs			0	B13
Accrued Self-Insurance Costs			0	B13
Other Contingent Liabilities			0	B13
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)			0	B13
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)			0	B13
Other			0	B13
			0	
			0	
Total	**348,864**	**0**	**348,864**	

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

PILS Tax Provision - Bridge Year

Wires Only

						Reference		
Regulatory Taxable Income						B1	-$ 2,136,588	**A**
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate				
Ontario (Max 11.5%)	11.5%	11.5%	-$ 245,708	11.5%	**B**			
Federal (Max 15%)	15.0%	15.0%	-$ 320,488	15.0%	**C**			
Combined effective tax rate (Max 26.5%)							26.50%	**D = B + C**
Total Income Taxes							$ -	**E = A * D**
Investment Tax Credits								**F**
Miscellaneous Tax Credits								**G**
Total Tax Credits							$ -	**H = F + G**
Corporate PILs/Income Tax Provision for Bridge Year							$ -	**I = E - H**

Note:

1. This is for the derivation of Bridge year PILs income tax expense and should not be used for Test year revenue requirement calculations.

Income Tax/PILs Workform for 2023 Filers

Adjusted Taxable Income - Bridge Year

	T2S1 line #	Working Paper Reference	Total for Regulated Utility
Income before PILs/Taxes	**(A + 101 + 102)**		2,550,824
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets	104		4,868,490
Amortization of intangible assets	106		
Recapture of capital cost allowance from Schedule 8	107	B8	0
Income inclusion under subparagraph 13(38)(d)(iii)	108		
Income or loss for tax purposes- joint ventures or partnerships	109		
Loss in equity of subsidiaries and affiliates	110		
Loss on disposal of assets	111		
Charitable donations and gifts from Schedule 2	112		
Taxable capital gains	113		
Political contributions	114		
Deferred and prepaid expenses	116		
Scientific research expenditures deducted on financial statements	118		
Capitalized interest	119		
Non-deductible club dues and fees	120		
Non-deductible meals and entertainment expense	121		
Non-deductible automobile expenses	122		
Non-deductible life insurance premiums	123		
Non-deductible company pension plans	124		
Tax reserves deducted in prior year	125	B13	0
Reserves from financial statements- balance at end of year	126	B13	348,864
Soft costs on construction and renovation of buildings	127		
Capital items expensed	206		
Debt issue expense	208		
Development expenses claimed in current year	212		
Financing fees deducted in books	216		
Gain on settlement of debt	220		
Non-deductible advertising	226		
Non-deductible interest	227		
Non-deductible legal and accounting fees	228		
Recapture of SR&ED expenditures	231		
Share issue expense	235		
Write down of capital property	236		
Amounts received in respect of qualifying environment trust per paragraphs 12(1)(z.1) and 12(1)(z.2)	237		
Other Additions			
Interest Expensed on Capital Leases	295		
Realized Income from Deferred Credit Accounts	295		
Pensions	295		
Non-deductible penalties	295		
	295		
	295		
ARO Accretion expense			
Capital Contributions Received (ITA 12(1)(x))			
Lease Inducements Received (ITA 12(1)(x))			
Deferred Revenue (ITA 12(1)(a))			
Prior Year Investment Tax Credits received			
Total Additions			**5,217,354**

Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	B8	9,309,554
Terminal loss from Schedule 8	404	B8	0
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves claimed in current year	413	B13	0
Reserves from financial statements - balance at beginning of year	414	B13	348,864
Contributions to deferred income plans	416		
Book income of joint venture or partnership	305		
Equity in income from subsidiary or affiliates	306		
Other deductions			
Interest capitalized for accounting deducted for tax	395		
Capital Lease Payments	395		
Non-taxable imputed interest income on deferral and variance accounts	395		
	395		
	395		
ARO Payments - Deductible for Tax when Paid			
ITA 13(7.4) Election - Capital Contributions Received			
ITA 13(7.4) Election - Apply Lease Inducement to cost of Leaseholds			
Deferred Revenue - ITA 20(1)(m) reserve			
Principal portion of lease payments			
Lease Inducement Book Amortization credit to income			
Financing fees for tax ITA 20(1)(e) and (e.1)			
amortization of contributed capital			246,348
Total Deductions		calculated	**9,904,766**
Net Income for Tax Purposes		calculated	**-2,136,588**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	B4	0
Net capital losses of previous tax years from Schedule 4	332	B4	0
Limited partnership losses of previous tax years from Schedule 4	335		
TAXABLE INCOME		calculated	**-2,136,588**

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Corporation Loss Continuity and Application

Schedule 4 Loss Carry Forward - Bridge Year

Non-Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	1,999,056	
Amount to be used in Bridge Year	B1	0	
Loss Carry Forward Generated in Bridge Year (if any)	B1	2,136,588	
Other Adjustments			
Balance available for use post Bridge Year	calculated	4,135,644	T4

Net Capital Loss Carry Forward Deduction		**Total**	
Actual Historical	H4	0	
Amount to be used in Bridge Year			
Loss Carry Forward Generated in Bridge Year (if any)	B1		
Other Adjustments			
Balance available for use post Bridge Year	calculated	0	T4

Ontario Energy Board

ıcome Tax/PILs Workform for 2023 Filers

Schedule 8 CCA - Bridge Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the bridge year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the bridge year (column 9 minus column 17)
1	Buildings, Distribution System (acq'd post 1987)	H8	$ 35,891,868							$ 35,891,868	$ -	$ -	0.50	$ -	$ -	4%			$ 1,435,675		$ 34,456,193
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	H8	$ 892,076	$ 35,828	$ 35,828					$ 927,904	$ -	$ 35,828	0.50	$ 17,914	$ -	6%			$ 56,749		$ 871,155
2	Distribution System (acq'd pre 1988)	H8	$ -							$ -	$ -	$ -		$ -	$ -	6%			$ -		$ -
3	Buildings (acq'd pre 1988)	H8	$ -							$ -	$ -	$ -		$ -	$ -	5%			$ -		$ -
6	Certain Buildings; Fences	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -
8	General Office Equipment, Furniture, Fixtures	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	20%			$ -		$ -
10	Motor Vehicles, Fleet	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
10.1	Certain Automobiles	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
12	Computer Application Software (Non-Systems)	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	100%			$ -		$ -
14	Limited Period Patents, Franchises, Concessions or Licences	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	H8	$ 1,741,453							$ 1,741,453	$ -	$ -		$ -	$ -	7%			$ 121,902		$ 1,619,551
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	5%			$ -		$ -
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -
42	Fibre Optic Cable	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	H8	$ -							$ -	$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	H8	$ -							$ -	$ -	$ -		$ -	$ -	45%			$ -		$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
47	Distribution System (acq'd post Feb 22/05)	H8	$ 52,249,054	$ 29,294,205	$ 29,294,205					$ 81,543,259	$ -	$ 29,294,205	0.50	$ 14,647,103	$ -	8%			$ 7,695,229		$ 73,848,030
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	H8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	55%			$ -		$ -
95	CWIP	H8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	0%			$ -		$ -
	TOTALS		$ 90,774,451	$ 29,330,033	$ 29,330,033	$ -	$ -	$ -	$ -	$ 120,104,484	$ -	$ 29,330,033		$ 14,665,016	$ -		$ -	$ -	$ 9,309,554	B1	$ 110,794,929

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 13 Tax Reserves - Bridge Year

Continuity of Reserves

						Bridge Year Adjustments					
Description	**Reference**	**Historical Utility Only**	**Eliminate Amounts Not Relevant for Bridge Year**	**Adjusted Utility Balance**		**Additions**	**Disposals**	**Balance for Bridge Year**		**Change During the Year**	**Disallowed Expenses**
Capital gains reserves ss.40(1)	H13	0		0				0	T13	0	
Tax Reserves Not Deducted for Accounting Purposes											
Reserve for doubtful accounts ss. 20(1)(l)	H13	348,864	-348,864	0				0	T13	0	
Reserve for goods and services not delivered ss. 20(1)(m)	H13	0		0				0	T13	0	
Reserve for unpaid amounts ss. 20(1)(n)	H13	0		0				0	T13	0	
Debt & share issue expenses ss. 20(1)(e)	H13	0		0				0	T13	0	
Other tax reserves	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		**348,864**	**-348,864**	**0**	B1	**0**	**0**	**0**	B1	**0**	**0**
Financial statement reserves (not deductible for tax purposes)											
General Reserve for Inventory Obsolescence (non-specific)	H13	0		0				0	T13	0	
General Reserve for Bad Debts	H13	348,864		348,864				348,864	T13	0	
Accrued Employee Future Benefits:	H13	0		0				0	T13	0	
- Medical and Life Insurance	H13	0		0				0	T13	0	
- Short & Long-term Disability	H13	0		0				0	T13	0	
- Accumulated Sick Leave	H13	0		0				0	T13	0	
- Termination Cost	H13	0		0				0	T13	0	
- Other Post-Employment Benefits	H13	0		0				0	T13	0	
Provision for Environmental Costs	H13	0		0				0	T13	0	
Restructuring Costs	H13	0		0				0	T13	0	
Accrued Contingent Litigation Costs	H13	0		0				0	T13	0	
Accrued Self-Insurance Costs	H13	0		0				0	T13	0	
Other Contingent Liabilities	H13	0		0				0	T13	0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	H13	0		0				0	T13	0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	H13	0		0				0	T13	0	
Other	H13	0		0				0	T13	0	
		0		0				0		0	
		0		0				0		0	
Total		**348,864**	**0**	**348,864**	B1	**0**	**0**	**348,864**	B1	**0**	**0**

Income Tax/PILs Workform for 2023 Filers

Ontario Energy Board

PILs Tax Provision - Test Year

								Wires Only	
Regulatory Taxable Income							T1	$ 1,592,430	A
	Tax Rate	Small Business Rate (If Applicable)	Taxes Payable	Effective Tax Rate					
Ontario (Max 11.5%)	11.5%	11.5%	$ 183,129	11.5%	B				
Federal (Max 15%)	15.0%	15.0%	$ 238,864	15.0%	C				
Combined effective tax rate (Max 26.5%)								26.50%	D = B + C
Total Income Taxes								**$ 421,994**	E = A * D
Investment Tax Credits									F
Miscellaneous Tax Credits									G
Total Tax Credits								$ -	H = F + G
Corporate PILs/Income Tax Provision for Test Year								**$ 421,994**	I = E - H S. Summary
Corporate PILs/Income Tax Provision Gross Up [1]						73.50%	J = 1-D	**$ 152,147**	K = I/J-I
Income Tax (grossed-up)								**$ 574,141**	L = K + I S. Summary

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Taxable Income - Test Year

	T2 S1 line #	Working Paper Reference	Test Year Taxable Income
Net Income Before Taxes		A.	4,714,129
Additions:			
Interest and penalties on taxes	103		
Amortization of tangible assets *2-4 ADJUSTED ACCOUNTING DATA P489*	104		5,425,413
Amortization of intangible assets *2-4 ADJUSTED ACCOUNTING DATA P490*	106		
Recapture of capital cost allowance from Schedule 8	107	T8	0
Tax reserves beginning of year	125	T13	0
Reserves from financial statements- balance at end of year	126	T13	350,000
Total Additions			**5,775,413**
Deductions:			
Gain on disposal of assets per financial statements	401		
Dividends not taxable under section 83	402		
Capital cost allowance from Schedule 8	403	T8	8,648,021
Terminal loss from Schedule 8	404	T8	0
Allowable business investment loss	406		
Deferred and prepaid expenses	409		
Scientific research expenses claimed in year	411		
Tax reserves end of year	413	T13	0
Reserves from financial statements - balance at beginning of year	414	T13	350,000
Amortization of Contributed Capital			351,857
Adjustment for Bill C-97 CCA Smoothing			-452,766
Total Deductions		calculated	**8,897,112**
NET INCOME FOR TAX PURPOSES		calculated	**1,592,430**
Charitable donations	311		
Taxable dividends received under section 112 or 113	320		
Non-capital losses of previous tax years from Schedule 4	331	T4	0
Net capital losses of previous tax years from Schedule 4	332	T4	0
Limited partnership losses of previous tax years from Schedule 4	335		
REGULATORY TAXABLE INCOME		calculated	**1,592,430**

T0

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 4 Loss Carry Forward - Test Year

Corporation Loss Continuity and Application

Non-Capital Loss Carry Forward Deduction	Working Paper Reference	Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	4,135,644		4,135,644
Amount to be used in Test Year and Price Cap Years	T1	0		0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)		0		
Amount to be used in Test Year	calculated	0		0
Loss Carry Forward Generated in Test Year (if any)	T1	0		0
Other Adjustments				0
Balance available for use in Future Years	calculated	4,135,644		4,135,644

Net Capital Loss Carry Forward Deduction		Total	Non-Distribution Portion	Utility Balance
Actual/Estimated Bridge Year Carried Forward	B4	0		0
Amount to be used in Test Year and Price Cap Years				0
Number of years loss until next cost of service (i.e. years the loss is to be spread over)				
Amount to be used in Test Year	T1	0		0
Loss Carry Forward Generated in Test Year (if any)				0
Other Adjustments				0
Balance available for use in Future Years		0		0

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 8 CCA - Test Year

(1) Class	Class Description	Working Paper Reference	(2) Undepreciated capital cost (UCC) at the beginning of the test year	(3) Cost of acquisitions during the year (new property must be available for use, except CWIP)	(4) Cost of acquisitions from column 3 that are accelerated investment incentive property (AIIP)	(5) Adjustments and transfers (enter amounts that will reduce the UCC as negatives)	(6) Amount from column 5 that is assistance received or receivable during the year for a property, subsequent to its disposition	(7) Amount from column 5 that is repaid during the year for a property, subsequent to its disposition	(8) Proceeds of dispositions	(9) UCC (column 2 plus column 3 plus or minus column 5 minus column 8)	(10) Proceeds of disposition available to reduce the UCC of AIIP (column 8 plus column 6 minus column 3 plus column 4 minus column 7) (if negative, enter "0")	(11) Net capital cost additions of AIIP acquired during the year (column 4 minus column 10) (if negative, enter "0")	Relevant factor	(12) UCC adjustment for AIIP acquired during the year (column 11 multiplied by the relevant factor)	(13) UCC adjustment for non-AIIP acquired during the year (0.5 multiplied by the result of column 3 minus column 4 minus column 6 plus column 7 minus column 8) (if negative, enter "0")	(14) CCA Rate %	(15) Recapture of CCA	(16) Terminal Loss	(17) CCA (for declining balance method, the result of column 9 plus column 12 minus column 13, multiplied by column 14)		(18) UCC at the end of the test year (column 9 minus column 17)
1	Buildings, Distribution System (acq'd post 1987)	B8	$ 34,456,1							$ 34,456,193	$ -	$ -	0.50	$ -	$ -	4%			$ 1,378,248		$ 33,077,946
1b	Non-Residential Buildings [Reg. 1100(1)(a.1) election]	B8	$ 871,155	577,035	577,035					$ 1,448,189	$ -	$ 577,035	0.50	$ 288,517	$ -	6%			$ 104,202		$ 1,343,987
2	Distribution System (acq'd pre 1988)	B8	$ -							$ -	$ -	$ -		$ -	$ -	6%			$ -		$ -
3	Buildings (acq'd pre 1988)	B8	$ -							$ -	$ -	$ -		$ -	$ -	5%			$ -		$ -
6	Certain Buildings; Fences	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	10%			$ -		$ -
8	General Office Equipment, Furniture, Fixtures	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	20%			$ -		$ -
10	Motor Vehicles, Fleet	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
10.1	Certain Automobiles	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
12	Computer Application Software (Non-Systems)	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	100%			$ -		$ -
14	Limited Period Patents, Franchises, Concessions or Licences	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	NA					$ -
14.1	Eligible Capital Property (acq'd pre Jan 1, 2017)	B8	$ 1,619,551							$ 1,619,551	$ -	$ -		$ -	$ -	7%			$ 113,369		$ 1,506,183
14.1	Eligible Capital Property (acq'd post Jan 1, 2017)	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	5%			$ -		$ -
17	Elec. Generation Equip. (Non-Bldng, acq'd post Feb 27/00); Roads, Lots, Storage	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	8%			$ -		$ -
42	Fibre Optic Cable	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	12%			$ -		$ -
43.1	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -	$ -	$ -	2.33	$ -	$ -	30%			$ -		$ -
43.2	Certain Clean Energy/Energy-Efficient Generation Equipment	B8	$ -							$ -	$ -	$ -	1.00	$ -	$ -	50%			$ -		$ -
45	Computers & System Software (acq'd post Mar 22/04 and pre Mar 19/07)	B8	$ -							$ -	$ -	$ -		$ -	$ -	45%			$ -		$ -
46	Data Network Infrastructure Equipment (acq'd post Mar 22/04)	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	30%			$ -		$ -
47	Distribution System (acq'd post Feb 22/05)	B8	$ 73,848,030	9,536,336	9,536,336					$ 83,384,366	$ -	$ 9,536,336	0.50	$ 4,768,168	$ -	8%			$ 7,052,203		$ 76,332,163
50	General Purpose Computer Hardware & Software (acq'd post Mar 18/07)	B8	$ -							$ -	$ -	$ -	0.50	$ -	$ -	55%			$ -		$ -
95	CWIP	B8	$ -							$ -	$ -	$ -	0.00	$ -	$ -	0%			$ -		$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
		B8	$ -							$ -	$ -	$ -		$ -	$ -						$ -
	TOTALS		$ 110,794,929	$ 10,113,371	$ 10,113,371	$ -	$ -	$ -	$ -	$ 120,908,300	$ -	$ 10,113,371		$ 5,056,685	$ -		$ -	$ -	$ 8,648,021	T1	$ 112,260,279

Only if election under ONTARIO REGULATION 162/01 ss. 5 or 7 filed in 2001 to have ITR 1102(14) apply

Ontario Energy Board

Income Tax/PILs Workform for 2023 Filers

Schedule 13 Tax Reserves - Test Year

Continuity of Reserves

Description	Working Paper Reference	Bridge Year	Eliminate Amounts Not Relevant for Test Year	Adjusted Utility Balance		Test Year Adjustments: Additions	Test Year Adjustments: Disposals	Balance for Test Year		Change During the Year	Disallowed Expenses
Capital Gains Reserves ss.40(1)	B13	0		0				0		0	
Tax Reserves Not Deducted for accounting purposes											
Reserve for doubtful accounts ss. 20(1)(l)	B13	0		0				0		0	
Reserve for goods and services not delivered ss. 20(1)(m)	B13	0		0				0		0	
Reserve for unpaid amounts ss. 20(1)(n)	B13	0		0				0		0	
Debt & Share Issue Expenses ss. 20(1)(e)	B13	0		0				0		0	
Other tax reserves	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		**0**	**0**	**0**	T1	**0**	**0**	**0**	T1	**0**	**0**
Financial Statement Reserves (not deductible for Tax Purposes)											
General Reserve for Inventory Obsolescence (non-specific)	B13	0		0				0		0	
General reserve for bad debts	B13	348,864	1,136	350,000				350,000		0	
Accrued Employee Future Benefits:	B13	0		0				0		0	
- Medical and Life Insurance	B13	0		0				0		0	
-Short & Long-term Disability	B13	0		0				0		0	
-Accmulated Sick Leave	B13	0		0				0		0	
- Termination Cost	B13	0		0				0		0	
- Other Post-Employment Benefits	B13	0		0				0		0	
Provision for Environmental Costs	B13	0		0				0		0	
Restructuring Costs	B13	0		0				0		0	
Accrued Contingent Litigation Costs	B13	0		0				0		0	
Accrued Self-Insurance Costs	B13	0		0				0		0	
Other Contingent Liabilities	B13	0		0				0		0	
Bonuses Accrued and Not Paid Within 180 Days of Year-End ss. 78(4)	B13	0		0				0		0	
Unpaid Amounts to Related Person and Not Paid Within 3 Taxation Years ss. 78(1)	B13	0		0				0		0	
Other	B13	0		0				0		0	
		0		0				0		0	
		0		0				0		0	
Total		**348,864**	**1,136**	**350,000**	T1	**0**	**0**	**350,000**	T1	**0**	**0**

EXHIBIT 7
COST ALLOCATION

TABLE OF CONTENTS

LIST OF TABLES

EXHIBIT 7: COST ALLOCATION

7.1 COST ALLOCATION STUDY REQUIREMENTS

In this application, PUC Distribution Inc. ("PUC") has used the 2023 version of the cost allocation model released by the OEB on May 27, 2022. The model has been loaded with 2023 Test year costs, customer numbers and demand values. The 2023 demand values were based on the 2023 weather normalized load forecast used to design rates. The various weighting factors used in the 2023 study have been updated and explained below.

7.1.1 Weighting Factors

PUC has reviewed its weighting factors from its 2018 COS Application and discussed with staff to determine that there have been no changes. Labour, materials, and outside costs required to perform the specific tasks below were estimated to determine each rate class factor. PUC assigned a weighting factor of 1 to the Residential rate class and further calculated the associated weighting factors for the remaining rate classes.

7.1.2 Services (Account 1855)

Table 7-1: Service Weighting Factors

Rate Class	Factor
Residential	1.0
General Service < 50 kW	0.7
General Service ≥ 50 kW	0.4
Sentinel Lighting	0.1
Street Lights	0.1
Unmetered Scattered Load	0.1

7.1.3 Billing and Collection (Accounts 5315 – 5340, except 5335)

Table 7-2: Billing Weighting Factors

Rate Class	Factor
Residential	1.0
General Service < 50 kW	1.1
General Service ≥ 50 kW	4.0
Sentinel Lighting	0.8
Street Lights	0.8
Unmetered Scattered Load	0.8

7.1.4 Meter Capital (Sheet I7.1)

Table 7-3: Meter Capital Installation Costs

Meter Type	Installation Cost per Meter
Smart Meter - Residential	$538
Smart Meter - General Service < 50 kW	$502
Smart Meter - General Service ≥ 50 kW	$993

7.1.5 Meter Reading (Sheet I7.2)

Table 7-4: Meter Reading Weighting Factor

Meter Type	Factor
Smart Meter - Residential	1.0
Smart Meter - General Service < 50 kW	0.9
Smart Meter - General Service ≥ 50 kW	1.9

7.1.6 Summary of Results and Proposed Changes

The data used in the updated cost allocation study is consistent with PUC's cost data that supports the proposed 2023 revenue requirement outlined in this application. PUC's assets were broken out into primary and secondary distribution functions using breakout percentages used in PUC's 2013 and 2018 cost of service rate application (EB-2012-0162/EB-2017-0071). The breakout of assets, capital contributions, depreciation, accumulated depreciation, customer data and load data by primary, line transformer and secondary categories were developed from the best data available to PUC, its engineering records, and its customer and financial information systems. An Excel version of the updated cost allocation study has been included with the filed application material. In addition, Appendix A - outlines Input Sheets I-6 & I-8 and Output Sheets O-1 & O-2 (first page only).

Capital contributions, depreciation, and accumulated depreciation by USoA are consistent with the information provided in the 2023 continuity statement shown in Exhibit 2. The rate class customer data used in the updated cost allocation study is consistent with the 2023 customer forecast outlined in Exhibit 3.

7.1.7 Load Profiles and Demand Allocators

PUC used 2021 actual data as the basis of updating its demand profile in the cost allocation model for the 2023 Test year. PUC realizes that 2021 consumption was affected by COVID, however this was the only year PUC was able to compile enough hourly smart meter data to update the demand profiles. PUC compared the results using the load forecast with 2020 and 2021 actual data, the load forecast with 2020 and 2021 normalized data and the 2018 Cost Allocation methodology which used a weighting factor from previous COS applications. Table 7-5 summarizes these results.

Table 7-5: 2023 Cost Allocation Model Results Using Different Demand Profile Updates

2023 Cost Allocation Model Results							
Method	Data Used	Residential	GS<50	GS>50	Street Light	Sentinel Light	USL
1	2020 and 2021 Actual Consumption Data to produce Load Forecast	$ 17,117,204	$ 3,616,755	$ 6,463,068	$ 363,504	$ 51,852	$ 53,105
2	2020 and 2021 COVID Normalized Consumption Data to produce load forecast	$ 17,128,169	$ 3,501,771	$ 6,667,329	$ 349,542	$ 52,120	$ 53,269
3	2018 COS Methodology Allocation Factor (2020 and 2021 Actual COVID Normalized)	$ 17,661,682	$ 3,510,521	$ 6,016,424	$ 372,677	$ 52,205	$ 51,979

Using Method 3, which is the methodology from PUC's 2018 application, is now outdated and allocates $600,000 more to the residential class. PUC has seen a shift in the contribution to its peak load between the rate classes. Additionally, PUC has winter peaks as compared to Southern Ontario which has summer peaks. This changes the dynamic of what rate classes contribute to PUC's peak load as compared to using the Hydro One report.

Method 1 uses the load forecast prior to PUC normalizing 2020 and 2021 actual data. This results in a very similar demand profile to Method 2, but PUC felt that it was not capturing the demand profile of the rate classes for future years.

PUC opted to use Method 2 to update its demand profile within the cost allocation model. This Method normalizes 2020 and 2021 COVID consumption data within the load forecast to better reflect the demand each rate class will contribute in future years. The following paragraphs will explain the steps involved to produce the demand profile which produced the demand allocators provide in Table 7-6. These demand allocators used the 2023 Load Forecast with regression analysis – filed in live excel format with this application.

7.1.7.1 Demand Profile Methodology

PUC used 2021 smart meter data as the basis of its demand profile update. Using the load forecast regression model filed in live format with this exhibit PUC compared the predicted purchases for 2021 with Heating Degree Days ("HDD") and Cooling Degree Days ("CDD") and compared that to predicted purchases in both absence of HDD and CDD. The results are shown in Table 7-6 and 7-7 below.

Table 7-6: HDD Predicted Purchases (in kWh)

	Predicted Purchases **with HDD**	Predicted Purchases **without HDD**	% Var
Jan-21	66,744,959	40,842,460	39%
Feb-21	63,702,938	35,631,368	44%
Mar-21	58,934,630	37,889,727	36%
Apr-21	49,897,946	36,108,726	28%
May-21	47,970,685	38,631,044	19%
Jun-21	44,385,446	41,896,981	6%
Jul-21	45,048,626	43,841,247	3%
Aug-21	49,109,188	48,817,873	1%
Sep-21	40,250,874	36,123,321	10%
Oct-21	45,136,066	37,809,309	16%
Nov-21	53,210,197	35,647,039	33%
Dec-21	62,902,728	40,116,953	36%
Total	**627,294,284**	**473,356,048**	

Table 7-7: CDD Predicted Purchases (in kWh)

	Predicted Purchases **with CDD**	Predicted Purchases **without CDD**	% Var
Jan-21	66,744,959	66,744,959	0%
Feb-21	63,702,938	63,702,938	0%
Mar-21	58,934,630	58,934,630	0%
Apr-21	49,897,946	49,897,946	0%
May-21	47,970,685	47,097,457	2%
Jun-21	44,385,446	41,286,103	7%
Jul-21	45,048,626	41,654,108	8%
Aug-21	49,109,188	40,672,089	17%
Sep-21	40,250,874	39,906,503	1%
Oct-21	45,136,066	44,754,797	1%
Nov-21	53,210,197	53,210,197	0%
Dec-21	62,902,728	62,902,728	0%
Total	**627,294,284**	**610,764,456**	

The “% Var” column is used to weather normalize the hourly data for the residential, GS<50 and GS>50 rate classes which is explained further below.

The next step taken was to aggregate all the weather data from the last 10 years to create a 10-year average of HDD and CDD by day for each month. If any data was missing from the weather station, the previous and next day was averaged to get the missing data. The daily results for each month were sorted from most HDD to least and compared yearly to one another to get the 10-year average. For example, if the coldest day in January 2012 was on the 15th and the coldest day in January 2013 was on the 29th, those two days would form part of the 10-year average for comparison purposes for that particular month.

Once this average was obtained it could be used to help weather normalize the hourly data. On January 1, 2021 at 1:00 a.m. PUC’s actual residential demand was 38,446 kWh.

Table 7-8: 2021 Residential Demand

Year	Month	Day	Hour	Residential Demand
				(A)
2021	1	1	1	38,446

To weather normalize this, first the 39% from Table 7-6 above indicates that 39% of the consumption in January is dependent on HDD. This means that 14,920 kWh is the portion of consumption affected by HDD shown below.

Table 7-9: HDD Weather Related Data

HDD Adj	HDD Weather Related Hourly Data	*Lookup-Ref*	HDD Weather Normal Hourly Data
(B)	(E) = (A) x (B)	(D)	(F) = (E) x (10yr Av/2021 yr)
39%	14,920	1.10	16,418

Then to weather normalize that amount for 10-year average, a ratio of 1.10 was applied to get the HDD weather normal hourly data affected by weather. This results in an increase of 1,497.94 kWh adjustment for HDD. PUC also repeated the same process for cooling degree days. Since January is very cold in Sault Ste. Marie, there is no cooling degree day adjustment.

Table 7-10: CDD Weather Related Data

CDD Adj	CDD Weather Related Hourly Data	*Lookup-Ref*	
(B)	(E) = (A) x (B)	(D)	(F) = (E) x (10yr Av/2021
0%	0.00	0.00	0.00

Once this is all summarized it results in an hourly data adjusted for HDD and CDD weather of 39,944 kWh.

Table 7-11: Hourly Data Adjusted for HDD & CDD Weather

Hourly Data Adjusted For HDD & CDD Weather	
(G) = (A) - (E) + (F) for HDD & CDD	*Change*
39,944	*1,498*

This process is repeated for every hour of every day for all rate classes effected by weather.

PUC has three rate classes not affected by weather which include Street Lights, Sentinel Lights and Unmetered Scattered Load. The hourly load profiles of these rate classes have been calculated using internal billing data.

Once the hourly data for each rate class is compiled, it is all aggregated by day into one sheet. A snapshot is provided in Table 7-12.

Table 7-12: Demand Snapshot

Year	Month	Day	Hour	Residential	General Service <50kW	General Service 50-999kW	General Service 1000-4999kW	StreetLights	Sentinel Lights	USL		Total LDC Demand
2021	1	1	1	38,446	9,588	22,660	0	600	36	106		71,436
2021	1	1	2	36,020	9,528	22,162	0	600	36	106		68,452
2021	1	1	3	34,531	9,450	22,274	0	600	36	106		66,997
2021	1	1	4	33,472	9,455	22,070	0	600	36	106		65,739
2021	1	1	5	33,225	9,432	22,234	0	600	36	106		65,633
2021	1	1	6	33,540	9,483	21,998	0	600	36	106		65,763

Table 7-12 is based on 2021 actual data. Next, the 2023 load forecast to ratio that data for what PUC predicts to occur in 2023 which is shown in Table 7-13.

Table 7-13: 2023 Load Forecast

Input: Test Year Load Forecast:							
274,738,681	79,051,528	221,450,388	2,459,994	193,841	878,528		578,772,961
Residential	**General Service <50kW**	**General Service 50-999kW**	**StreetLights**	**Sentinel Lights**	**USL**		**Total LDC Demand**
36,410	8,816	24,987	600	34	106		70,952
34,112	8,761	24,438	600	34	106		68,051
32,702	8,689	24,561	600	34	106		66,692
31,699	8,693	24,337	600	34	106		65,469
31,465	8,673	24,517	600	34	106		65,395
31,763	8,720	24,257	600	34	106		65,480

The final step is to obtain the Non-Co-incident Peak and Co-Incident peak. Table 7-14 summarizes the Non-Co-incident Peaks used and input into Tab I8 of the 2023 Cost Allocation Model. Table 7-15 summarizes the Co-incident Peaks and the demand allocators input into Tab I8 of the 2023 Cost Allocation Model.

Table 7-14: Non-Co-Incident Peak Demand Allocators

	Residential	General Service <50kW	General Service 50-999kW	StreetLights	Sentinel Lights	USL	LDC Monthly Max Demand
Jan	59,195	13,365	35,450	600	34	106	101,018
Feb	61,091	14,407	37,114	600	40	106	103,944
Mar	53,727	13,924	35,952	600	40	106	97,949
Apr	43,761	12,844	33,331	600	48	106	84,548
May	40,637	10,942	30,301	600	52	106	73,410
Jun	48,595	12,278	34,244	600	63	106	91,101
Jul	45,609	13,494	33,058	600	60	106	84,297
Aug	47,568	14,288	33,654	600	53	106	88,591
Sep	34,647	12,205	31,125	600	49	106	69,891
Oct	39,680	18,427	31,894	600	42	106	74,669
Nov	51,538	14,435	30,839	600	38	106	91,666
Dec	57,681	15,216	33,020	600	35	106	99,770
1NCP	**61,091**	**18,427**	**37,114**	**600**	**63**	**106**	
4NCP	**231,694**	**62,486**	**142,759**	**2,401**	**228**	**423**	
12NCP	**583,727**	**165,825**	**399,980**	**7,202**	**554**	**1,268**	

Table 7-15: Co-Incident Peak Demand Allocators

	Residential	General Service <50kW	GS 50 - 999kW	Street Lighting	Sentinel Lighting	USL	LDC Monthly Coincident Peak Demand
Jan	55,229	11,831	33,218	600	34	106	101,018
Feb	57,694	12,145	33,359	600	40	106	103,944
Mar	53,727	11,365	32,112	600	40	106	97,949
Apr	40,874	11,370	32,209	0	0	95	84,548
May	40,637	8,315	24,364	0	0	95	73,410
Jun	48,535	10,781	31,690	0	0	95	91,101
Jul	40,103	12,579	31,520	0	0	95	84,297
Aug	45,195	12,212	31,089	0	0	95	88,591
Sep	31,294	9,841	28,660	0	0	95	69,891
Oct	27,032	18,427	29,114	0	0	95	74,669
Nov	51,309	11,969	28,243	0	38	106	91,666
Dec	57,681	12,704	29,244	0	35	106	99,770
1CP	**57,694**	**12,145**	**33,359**	**600**	**40**	**106**	**103,944**
4CP	**224,331**	**48,044**	**127,933**	**1,800**	**149**	**423**	**402,681**
12CP	**549,310**	**143,538**	**364,822**	**1,800**	**187**	**1,195**	**1,060,854**

7.1.8 Specific Customer Classes

7.1.8.1 Large General Service and Large User Classes

PUC is aware of the transformer allowance contained within the cost allocation model.

7.1.8.2 Embedded Distributor Class

PUC does not have an embedded distributor rate class.

7.1.8.3 Unmetered Loads

PUC communicates with unmetered load customers, including Street Lighting customers, to assist them in understanding the regulatory context in which distributors operate and how it affects unmetered load customers. This communication takes place on an on-going basis and is not driven by the rate application process.

7.1.8.4 microFIT Class

PUC is not proposing to include microFIT as a separate class in the cost allocation model in 2023. PUC understands that the cost allocation model will produce a calculation of unit costs which the OEB will use to update the uniform microFIT rate at a future date.

7.1.8.5 Standby Rates

PUC does not charge Standby Rates to any of its customers as of August 31, 2022.

7.1.9 New Customer Classes

PUC is not proposing to include a new customer class.

7.1.10 Eliminated Customer Classes

PUC is not proposing to eliminate a rate class.

7.2 CLASS REVENUE REQUIREMENTS

The following Table 7-16 provides information on calculated class revenue. The resulting 2023 proposed base revenue will be the amount used in Exhibit 8 to design the proposed distribution charges in this application.

Table 7-16 Calculated Class Revenue –
(Consistent with RRWF, Tab 11 Cost Allocation, Calculated Class Revenues)

Rate Class	2023 Base Revenue at Existing Rates	2023 Proposed Base Revenue Allocated at Existing Rates Proportion	2023 Proposed Base Revenue	Miscellaneous Revenue
Residential	$12,939,404	$15,344,320	$15,344,320	$1,774,752
General Service < 50 kW	$3,189,277	$3,782,036	$3,782,036	$345,328
General Service ≥ 50 kW	$4,653,058	$5,517,875	$5,517,875	$559,803
Sentinel Lighting	$36,638	$43,448	$43,448	$8,575
Street Lights	$222,463	$263,810	$263,810	$53,728
Unmetered Scattered Load	$42,539	$50,446	$50,446	$8,079
Total	$21,083,380	$25,001,934	$25,001,935	$2,750,265

7.3 REVENUE-TO-COST RATIOS

The results of a cost allocation study are typically presented in the form of revenue-to-cost ratios. The ratio is shown by rate classification and is the percentage of distribution revenue collected by rate classification compared to the costs allocated to the classification. The percentage identifies the rate classifications that are being subsidized and those that are over-contributing. A percentage of less than 100% means the rate classification is under-contributing and is being subsidized by other classes of customers. A percentage of greater than 100% indicates the rate classification is over-contributing and is subsidizing other classes of customers.

In the OEB's Letter from June 12, 2015[1], the Board established what it considered to be the appropriate ranges of revenue to cost ratios which are summarized in Table 7-17 below. In addition, Table 7-17 provides PUC's revenue-to-cost ratios from the 2018 application and the updated 2023 cost allocation study.

Table 7-17 Revenue-to-Cost Ratios – (Consistent with RRWF, Tab 11 Cost Allocation, Proposed & Rebalancing Revenue to Cost Ratios)

Rate Class	2018 Board Approved Cost Allocation Study	2023 Cost Allocation Study	2023 Proposed Ratios	OEB Targets Min to Max	
Residential	92.62%	99.95%	99.95%	85.0%	115.0%
General Service < 50 kW	116.08%	117.87%	117.87%	80.0%	120.0%
General Service ≥ 50 kW	111.07%	91.16%	91.16%	80.0%	120.0%
Sentinel Lighting	97.22%	99.81%	99.81%	80.0%	120.0%
Street Lights	120.00%	90.84%	90.84%	80.0%	120.0%
Unmetered Scattered Load	112.71%	109.87%	109.87%	80.0%	120.0%

The 2023 Cost Allocation Study percentages all fall within the OEB targets, but PUC has decided to adjust them closer to each rate classes portion of revenue-to-costs. Since the demand profile was updated in this rate application, it has caused a shift in the revenue-to-cost percentages for this application compared to the 2018 application.

Three rate classes were chosen to change the revenue-to-cost percentages from the default presented in the 2023 Cost allocation model. First the General Service <50kW rate class was adjusted down to 110%. This amount was allocated to General Service >50kW and Street Light rate class in unity bringing them both up to 95.07%. PUC ran these changes through the bill impacts model and feels that the bill impacts presented in Exhibit 8 are still reasonable for all rate classes.

[1] OEB letter, June 12, 2005, Review of Cost Allocation Policy for Unmetered Loads OEB File No. EB-2012-0383, Issuance of New Cost Allocation Policy for Street Lighting Rate Class

APPENDIX A
2023 Cost Allocation Model

Input Sheets I-6 & I-8

Output Sheets O-1 & O-2 (first page only).

Ontario Energy Board

2023 Cost Allocation Model

EB-2022-0059

Sheet I6.1 Revenue Worksheet - Final

Total kWhs from Load Forecast	578,772,961

Total kWs from Load Forecast	555,454

Deficiency/sufficiency (RRWF 8. cell F51)	- 3,918,555

Miscellaneous Revenue (RRWF 5. cell F48)	2,750,265

			1	**2**	**3**	**7**	**8**	**9**
	ID	**Total**	**Residential**	**GS <50**	**GS>50-Regular**	**Street Light**	**Sentinel**	**Unmetered Scattered Load**
Billing Data								
Forecast kWh	**CEN**	578,772,961	274,738,681	79,051,528	221,450,388	2,459,994	193,841	878,528
Forecast kW	**CDEM**	555,454			547,687	7,200	566	
Forecast kW, included in CDEM, of customers receiving line transformer allowance		112,000			112,000			
Optional - Forecast kWh, included in CEN, from customers that receive a line transformation allowance on a kWh basis. In most cases this will not be applicable and will be left blank.		-						
KWh excluding KWh from Wholesale Market Participants	**CEN EWMP**	578,772,961	274,738,681	79,051,528	221,450,388	2,459,994	193,841	878,528
Existing Monthly Charge			$33.72	$22.32	$123.27	$1.47	$3.83	$13.67
Existing Distribution kWh Rate				$0.0268				$0.0412
Existing Distribution kW Rate					$7.2479	$9.6161	$35.7037	
Existing TOA Rate					$0.60			
Additional Charges			$662,626.00	$160,040.00	$241,816.00	$11,454.00	$1,852.00	$2,243.00
Distribution Revenue from Rates		$21,150,579	$12,939,404	$3,189,277	$4,720,258	$222,463	$36,638	$42,539
Transformer Ownership Allowance		$67,200	$0	$0	$67,200	$0	$0	$0
Net Class Revenue	**CREV**	$21,083,379	$12,939,404	$3,189,277	$4,653,058	$222,463	$36,638	$42,539

Ontario Energy Board

2023 Cost Allocation Model

EB-2022-0059

Sheet I6.2 Customer Data Worksheet - Final

			1	2	3	7	8	9
	ID	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Billing Data								
Bad Debt 3 Year Historical Average	BDHA	$366,575	$275,704	$54,065	$36,805	$0	$0	$0
Late Payment 3 Year Historical Average	LPHA	$257,333	$189,877	$36,868	$30,588			
Number of Bills	CNB	409,368	364,080	40,800.00	4,128.00	48.00	12.00	300.00
Number of Devices	CDEV					8,037		
Number of Connections (Unmetered)	CCON	8,649				8,037	317	295
Total Number of Customers	CCA	34,114	30,340	3,400	344	4	1	25
Bulk Customer Base	CCB	-						
Primary Customer Base	CCP	34,418	30,340	3,435	303	314	1	25
Line Transformer Customer Base	CCLT	34,368	30,340	3,435	253	314	1	25
Secondary Customer Base	CCS	33,341	30,340	2,840	135		1	25
Weighted - Services	CWCS	32,760	30,340	1,931	57	402	16	15
Weighted Meter -Capital	CWMC	18,226,142	16,252,980	1,683,206	289,956	-	-	-
Weighted Meter Reading	CWMR	40,555	30,340	3,400	6,815	-	-	-
Weighted Bills	CWNB	426,322	364,080	45,288	16,677	37	9	231

Bad Debt Data

Historic Year:	2019	378,475	286,175	54,008	38,291			
Historic Year:	2020	354,696	266,022	53,204	35,470			
Historic Year:	2021	366,554	274,915	54,983	36,655			
Three-year average		**366,575**	**275,704**	**54,065**	**36,805**	-	-	-

Street Lighting Adjustment Factors

NCP Test Results	4 NCP

	Primary Asset Data		Line Transformer Asset Data	
Class	**Customers/ Devices**	**4 NCP**	**Customers/ Devices**	**4 NCP**
Residential	30,340	231,694	30,340	231,694
Street Light	8,037	2,401	8,037	2,401

Street Lighting Adjustment Factors	
Primary	25.5668
Line Transformer	25.5668

Ontario Energy Board

2023 Cost Allocation Model

EB-2022-0059

Sheet O1 Revenue to Cost Summary Worksheet - Final

Instructions:
Please see the first tab in this workbook for detailed instructions

Class Revenue, Cost Analysis, and Return on Rate Base

			1	2	3	7	8	9
Rate Base Assets		Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
crev	Distribution Revenue at Existing Rates	$21,083,379	$12,939,404	$3,189,277	$4,653,058	$222,463	$36,638	$42,539
mi	Miscellaneous Revenue (mi)	$2,750,265	$1,774,752	$345,328	$559,803	$53,728	$8,575	$8,079
		Miscellaneous Revenue Input equals Output						
	Total Revenue at Existing Rates	$23,833,644	**$14,714,155**	**$3,534,605**	**$5,212,861**	**$276,191**	**$45,214**	**$50,618**
	Factor required to recover deficiency (1 + D)	1.1859						
	Distribution Revenue at Status Quo Rates	$25,001,935	$15,344,320	$3,782,036	$5,517,875	$263,810	$43,448	$50,446
	Miscellaneous Revenue (mi)	$2,750,265	$1,774,752	$345,328	$559,803	$53,728	$8,575	$8,079
	Total Revenue at Status Quo Rates	$27,752,200	**$17,119,072**	**$4,127,364**	**$6,077,678**	**$317,538**	**$52,023**	**$58,525**
	Expenses							
di	Distribution Costs (di)	$6,612,535	$3,972,990	$850,817	$1,674,974	$80,612	$16,670	$16,473
cu	Customer Related Costs (cu)	$1,958,371	$1,570,497	$201,427	$126,331	$55,561	$2,202	$2,353
ad	General and Administration (ad)	$5,378,385	$3,440,394	$664,878	$1,168,603	$81,468	$11,511	$11,532
dep	Depreciation and Amortization (dep)	$5,425,413	$3,298,583	$688,272	$1,361,363	$59,043	$8,895	$9,257
INPUT	PILs (INPUT)	$574,141	$332,095	$75,139	$160,099	$4,993	$880	$936
INT	Interest	$3,089,225	$1,786,867	$404,292	$861,428	$26,867	$4,736	$5,035
	Total Expenses	$23,038,070	**$14,401,425**	**$2,884,825**	**$5,352,798**	**$308,543**	**$44,893**	**$45,586**
	Direct Allocation	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
NI	Allocated Net Income (NI)	$4,714,129	$2,726,744	$616,946	$1,314,531	$40,998	$7,227	$7,683
	Revenue Requirement (includes NI)	$27,752,200	$17,128,169	$3,501,771	$6,667,329	$349,542	$52,120	$53,269
		Revenue Requirement Input equals Output						
	Rate Base Calculation							
	Net Assets							
dp	Distribution Plant - Gross	$186,612,420	$110,607,083	$24,090,003	$49,359,589	$1,870,666	$336,932	$348,147
gp	General Plant - Gross	$5,516,178	$3,228,356	$718,741	$1,495,693	$53,049	$10,037	$10,301
accum dep	Accumulated Depreciation	($36,460,701)	($22,560,605)	($4,539,970)	($8,837,892)	($403,804)	($56,595)	($61,835)
co	Capital Contribution	($25,236,014)	($15,804,439)	($3,201,121)	($5,675,940)	($382,045)	($89,334)	($83,134)
	Total Net Plant	$130,431,883	**$75,470,395**	**$17,067,653**	**$36,341,450**	**$1,137,866**	**$201,040**	**$213,479**
	Directly Allocated Net Fixed Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
COP	Cost of Power (COP)	$61,481,413	$29,258,624	$8,391,185	$23,457,434	$260,578	$20,533	$93,059
	OM&A Expenses	$13,949,291	$8,983,880	$1,717,122	$2,969,908	$217,640	$30,383	$30,358
	Directly Allocated Expenses	$0	$0	$0	$0	$0	$0	$0
	Subtotal	*$75,430,704*	***$38,242,504***	***$10,108,307***	***$26,427,342***	***$478,218***	***$50,916***	***$123,417***
	Working Capital	$5,657,303	**$2,868,188**	**$758,123**	**$1,982,051**	**$35,866**	**$3,819**	**$9,256**
	Total Rate Base	$136,089,186	**$78,338,583**	**$17,825,776**	**$38,323,500**	**$1,173,732**	**$204,859**	**$222,736**
		Rate Base Input equals Output						
	Equity Component of Rate Base	$54,435,674	**$31,335,433**	**$7,130,310**	**$15,329,400**	**$469,493**	**$81,944**	**$89,094**
	Net Income on Allocated Assets	$4,714,129	**$2,717,647**	**$1,242,539**	**$724,880**	**$8,995**	**$7,130**	**$12,938**
	Net Income on Direct Allocation Assets	$0	**$0**	**$0**	**$0**	**$0**	**$0**	**$0**
	Net Income	$4,714,129	**$2,717,647**	**$1,242,539**	**$724,880**	**$8,995**	**$7,130**	**$12,938**
	RATIOS ANALYSIS							
	REVENUE TO EXPENSES STATUS QUO%	100.00%	**99.95%**	**117.87%**	**91.16%**	**90.84%**	**99.81%**	**109.87%**
	EXISTING REVENUE MINUS ALLOCATED COSTS	($3,918,555)	($2,414,013)	$32,834	($1,454,468)	($73,350)	($6,907)	($2,651)
		Deficiency Input equals Output						
	STATUS QUO REVENUE MINUS ALLOCATED COSTS	($0)	($9,097)	$625,593	($589,651)	($32,003)	($97)	$5,256
	RETURN ON EQUITY COMPONENT OF RATE BASE	8.66%	8.67%	17.43%	4.73%	1.92%	8.70%	14.52%

Ontario Energy Board

2023 Cost Allocation Model

EB-2022-0059

Sheet O2 Monthly Fixed Charge Min. & Max. Worksheet - Final

Output sheet showing minimum and maximum level for Monthly Fixed Charge

Summary

	1	2	3	7	8	9
	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
Customer Unit Cost per month - Avoided Cost	$4.45	$4.03	$15.88	$0.57	$0.56	$0.64
Customer Unit Cost per month - Directly Related	$6.63	$6.29	$30.10	$0.92	$0.92	$1.05
Customer Unit Cost per month - Minimum System with PLCC Adjustment	$20.40	$19.84	$53.50	$2.82	$13.39	$13.55
Existing Approved Fixed Charge	$33.72	$22.32	$123.27	$1.47	$3.83	$13.67

Information to be Used to Allocate PILs, ROD, ROE and A&G

		1	2	3	7	8	9
	Total	Residential	GS <50	GS>50-Regular	Street Light	Sentinel	Unmetered Scattered Load
General Plant - Gross Assets	$5,516,178	$3,228,356	$718,741	$1,495,693	$53,049	$10,037	$10,301
General Plant - Accumulated Depreciation	($1,701,790)	($995,977)	($221,738)	($461,435)	($16,366)	($3,097)	($3,178)
General Plant - Net Fixed Assets	$3,814,387	$2,232,379	$497,003	$1,034,258	$36,683	$6,941	$7,123
General Plant - Depreciation	($121,558)	($71,142)	($15,839)	($32,960)	($1,169)	($221)	($227)
Total Net Fixed Assets Excluding General Plant	$126,617,496	$73,238,016	$16,570,649	$35,307,191	$1,101,183	$194,100	$206,356
Total Administration and General Expense	$5,378,385	$3,440,394	$664,878	$1,168,603	$81,468	$11,511	$11,532
Total O&M	$8,414,934	$5,442,607	$1,033,095	$1,768,525	$133,694	$18,528	$18,484

EXHIBIT 8

RATE DESIGN

PUC Distribution Inc • EB-2022-0059 • Filed: August 31,2022

TABLE OF CONTENTS

LIST OF TABLES

EXHIBIT 8: RATE DESIGN

This Exhibit documents the calculation of PUC Distribution Inc.'s ("PUC") proposed distribution rates by rate class for the test year, based on the rate design as proposed in this Exhibit.

PUC has determined its total service revenue requirement to be $27,752,199. The total revenue offsets in the amount of $2,750,265 reduces PUC's total service revenue requirement to a base revenue requirement of $25,001,934 which is used to determine the proposed distribution rates. The base revenue requirement is derived from PUC's capital and operating forecasts, weather normalized usage, forecasted customer counts, and regulated return on rate base. The revenue requirement is summarized in Table 8-1 below:

Table 8-1: Calculation of Base Revenue Requirement

Description	Amount
OM&A Expenses	$13,949,291
Amortization Expenses	$5,425,413
Regulated Return On Capital	$7,803,354
PILs	$574,141
Service Revenue Requirement	**$27,752,199**
Less Revenue Offsets	$2,750,265
Base Revenue Requirement	**$25,001,934**

The outstanding base revenue requirement is allocated to the various rate classes as outlined in Exhibit 7 – Cost Allocation, Table 7-2. The following Table 8-2 outlines the allocation of the base revenue requirement to the rate classes.

Table 8-2: Proposed Apportionment of Base Revenue to Rate Classes

Rate Class	2023 Proposed Base Revenue Requirement
Residential	15,344,320
General Service < 50 kW	3,782,036
General Service 50 to 4,999 kW	5,517,875
Street Lighting	$263,810
Sentinel Lighting	$43,448
Unmetered Scattered Load	$50,446
Total	**$25,001,934**

8.1 FIXED/VARIABLE PROPORTION

Based on applying the existing approved monthly service charges to the forecasted number of customers for PUC along with the existing approved distribution volumetric charge, excluding rate riders, and the transformer allowance, to the PUC forecasted volumes, the following Table 8-3 outlines PUC's current split between fixed and variable distribution revenue.

Table 8-3: Current Fixed/Variable Split

Rate Class	2023 Fixed Base Revenue with 2022 Approved Rates	2023 Variable Base Revenue with 2022 Approved Rates	2023 Total Base Revenue with 2022 Approved Rates	Fixed Revenue Proportion	Variable Revenue Proportion
Residential	$15,344,320	$0	$15,344,320	100.0%	0.0%
General Service < 50 kW	$1,138,454	$2,643,582	$3,782,036	30.1%	69.9%
General Service 50 to 4,999 kW	$635,988	$4,881,887	$5,517,875	11.5%	88.5%
Street Lighting	$18,179	$25,269	$43,448	41.8%	58.2%
Sentinel Lighting	$177,272	$86,538	$263,810	67.2%	32.8%
Unmetered Scattered Load	$5,152	$45,293	$50,446	10.2%	89.8%
Total	**$17,319,366**	**$7,682,569**	**$25,001,934**	**69.3%**	**30.7%**

PUC is proposing to maintain this fixed/variable split assumed in current rates to design the proposed monthly service charges. This proposal is consistent with PUC's 2018 COS application.

Table 8-4 shows the breakdown of the proposed fixed/variable split, the resulting monthly service charge with the floor and ceiling as calculated in the cost allocation study. This proposal is consistent with the Ontario Energy Board's ("Board") Decision in the following cases:

a) Centre Wellington Hydro Ltd. - 2013 Cost of Service Rate (*EB-2012-0113*);
b) Atikokan Hydro Inc. - 2012 Cost of Service Rate (*EB-2011-0293*);
c) Espanola Regional Hydro Distribution Corporation - 2012 Cost of Service Rate (*EB-2011-0319*);
d) Horizon Utilities Corporation - 2011 Cost of Service Application (*EB-2010-0131*);
e) Hydro One Brampton Networks Inc. - 2011 Cost of Service Application (*EB-2010-0132*);
f) Kenora Hydro Electric Corporation Ltd. - 2011 Cost of Service Application (*EB-2010-0135*); and
g) In Horizon Utilities Corporation's ("Horizon") decision on their 2015 rates (EB-2014-0002) the Board approved Horizon's proposal to maintain the fixed/variable split. The following outlines the Board findings with regards to proposed fixed/variable split.

   The Board accepts Horizon's proposal. While the Board's current policy direction is to move toward an increased fixed charge, this consideration was not the sole basis upon which the Board reached its Decision. The Settlement Agreement contains a re-opener provision which would address any policy change related to an increased fixed charge.

   A fixed/variable split above the ceiling was approved in Horizon's last cost of service proceeding. In this application, Horizon has maintained the fixed/variable split.

   The Board notes that a principle of rate design is that in most circumstances rate stability is desirable. Counter-direction in rates can be confusing to ratepayers. Horizon has chosen to maintain a fixed/variable split that moves above the ceiling. Intervenors argue that this is contrary to the Board's report in EB-2007-0667.

Table 8-4: Proposed Fixed/Variable Split

Rate Class	Total Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue	Annualized Customers / Connections	Proposed Monthly Service Charge	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model)
Residential	$15,344,320	100.0%	$15,344,320	364,080	$42.15	20.39
General Service < 50 kW	$3,782,036	30.1%	$1,138,454	40,800	$27.90	19.84
General Service 50 to 4,999 kW	$5,517,875	11.5%	$635,988	4,128	$154.07	53.50
Sentinel Lighting	$43,448	41.8%	$18,179	3,804	$4.78	2.82
Street Lighting	$263,810	67.2%	$177,272	96,444	$1.84	13.39
Unmetered Scattered Load	$50,446	10.2%	$5,127	300	$17.09	13.67
Total	**$25,001,935**		**$17,319,339**	**509,556**		

Based on the above, it is PUC's proposal that it would be reasonable to maintain the current fixed/variable split for all rate classes, and not move a higher proportion of costs to the usage rate.

The following Table 8-5 outlines the proposed monthly service charge by rate class for PUC.

Table 8-5: Proposed Monthly Service Charge

Rate Class	Total Base Revenue Requirement	Fixed Revenue Proportion	Fixed Revenue	Annualized Customers / Connections	Proposed Monthly Service Charge
Residential	$15,344,320	100.0%	$15,344,320	364,080	$42.15
General Service < 50 kW	$3,782,036	30.1%	$1,138,454	40,800	$27.90
General Service 50 to 4,999 kW	$5,517,875	11.5%	$635,988	4,128	$154.07
Sentinel Lighting	$43,448	41.8%	$18,179	3,804	$4.78
Street Lighting	$263,810	67.2%	$177,272	96,444	$1.84
Unmetered Scattered Load	$50,446	10.2%	$5,127	300	$17.09
Total	**$25,001,935**		**$17,319,339**	**509,556**	

For comparison purposes, the following Table 8-6 provides the current and proposed monthly service charge by rate class as well as monthly service charge information from the cost allocation model.

Table 8-6: Monthly Service Charge Comparison

Rate Class	Current 2022 Monthly Service Charge	Proposed 2023 Monthly Service Charge	Minimum System with PLCC Adustment (Ceiling Fixed Charge From Cost Allocation Model
Residential	$33.72	$42.15	$20.43
General Service < 50 kW	$22.32	$27.90	$19.53
General Service 50 to 4,999 kW	$123.27	$154.07	$59.71
Sentinel Lighting	$3.83	$4.78	$13.32
Street Lighting	$1.47	$1.84	$3.01
Unmetered Scattered Load	$13.67	$17.09	$13.47

8.1.1 Proposed Volumetric Charges

The variable distribution charge is calculated by dividing the variable distribution portion of the base revenue requirement by the appropriate PUC Test year usage, kWh, or kW, as the class charge determinant.

The following Table 8-7 provides PUC's calculations of its proposed variable distribution charges for the Test year which maintains the same fixed/variable split used in designing the current approved rates.

Table 8-7: Proposed Distribution Volumetric Charge

Rate Class	Total Base Revenue Requirement	Variable Revenue Proportion	Variable Revenue	Annualized kWh or kW as required	Unit of Measure	Proposed Distribution Volumtric Charge before Transformer Allowance
Residential	$15,344,320	0.0%	$0	274,738,681	kWh	$0.0000
General Service < 50 kW	$3,782,036	69.9%	$2,643,582	79,051,528	kWh	$0.0334
General Service 50 to 4,999 kW	$5,517,875	88.5%	$4,949,087	547,687	kW	$9.0363
Sentinel Lighting	$43,448	58.2%	$25,269	566	kW	$44.6252
Street Lighting	$263,810	32.8%	$86,538	7,200	kW	$12.0191
Unmetered Scattered Load	$50,446	89.8%	$45,293	878,528	kWh	$0.0516
Total	**$25,001,935**		**$7,749,769**			

8.1.2 Proposed Adjustment for Transformer Allowance

Currently, PUC provides a transformer allowance to those customers that own their transformation facilities. PUC proposes to maintain the current approved transformer ownership allowance of $0.60 per kW ("Transformer Allowance"). The Transformer Allowance is intended to reflect the costs to a distributor of providing step down transformation facilities to the customer's utilization voltage level. Since the distributor provides electricity at utilization voltage, the cost of this transformation is captured in and recovered through the distribution rates. Therefore, when a customer provides its own step down transformation from primary to secondary, it should receive a credit of these costs already included in the distribution rates.

The amount of Transformer Allowance expected to be provided to the customers in the General Service 50 to 4,999 kW class that owns their transformers has been included in the volumetric charge for this class. This means the General Service 50 to 4,999 kW volumetric charge of $8.9136 per kW will increase by $0.1227 per kW to a total of $9.0363 per kW to recover the amount of the Transformer Allowance over all kWs in the General Service 50 to 4,999 kW class.

8.1.3 Proposed Distribution Rates

The following Table 8-8 sets out PUC's proposed electricity distribution rates based on the foregoing calculations, including adjustments for the recovery of transformer allowance.

Table 8-8: Proposed Distribution Rates

Rate Class	Proposed Monthly Service Charge	Unit of Measure	Proposed Distribution Volumetric Charge incl Transformer Allowance Adjustment
Residential	$42.15	kWh	$0.0000
General Service < 50 kW	$27.90	kWh	$0.0334
General Service 50 to 4,999 kW	$154.07	kW	$9.0363
Sentinel Lighting	$4.78	kW	$44.6252
Street Lighting	$1.84	kW	$12.0191
Unmetered Scattered Load	$17.09	kW	$0.0516
Transformer Discount		kW	($0.6000)

8.2 RETAIL TRANSMISSION SERVICE RATES

PUC receives wholesale transmission service from metered points that are directly connected to the grid. PUC is billed Uniform Transmission Rates by the IESO on all capacity delivered through these points. PUC passes these charges unto their customers with Board approved Retail Transmission Service Rates ("RTSR"). In order to determine the RTSR, PUC has completed the 2023_RTSR_Workform and it has been filed as part of this application. The RTSR information is also consistent with the Working Capital Allowance calculation. The RTSR Work Form is also provided in Appendix A in PDF format. Table 8-9 provides the RTSR rates generated from the PUC Distribution 2023_RTSR_Workform.

Table 8-9: Proposed Retail Transmission Rates

	Retail Transmission Network Rates	
Rate Class	**Per kWh**	**Per kW**
Residential	$0.0084	
General Service < 50 kW	$0.0078	
General Service 50 to 4,999 kW		$3.1660
General Service ≥ 50 kW Interval		$3.9826
Sentinel Lighting		$2.4003
Street Lighting		$2.3886
Unmetered Scattered Load	$0.0078	

8.3 RETAIL SERVICE CHARGES

As outlined in Exhibit 9 Section 9.5.2.4, PUC is claiming the disposition for amounts forecasted to April 30, 2023. PUC is proposing to dispose of the balances in Account 1518 RCVA Retail and Account 1548 RCVA STR in this Application and to discontinue these accounts after April 1, 2023 on the assumption that PUC's 2023 rates are approved effective May 1, 2023.

8.4 REGULATORY CHARGES

On December 16, 2021, the Board issued a Decision with Reasons and Rate Order (EB-2021-0300) establishing that the Wholesale Market Service ("WMS") used by rate-regulated distributors to bill their customers shall be $0.0030 per kilowatt-hour, effective January 1, 2022. For Class B customers a CBR component of $0.0004 per kilowatt-hour shall be added to the WMS rate for a total of $0.0034 per kilowatt-hour. For Class A customers, distributors shall bill the actual CBR costs to Class A customers in proportion to their contribution to peak. Furthermore, the same decision established that the Rural or Remote Electricity Rate Protection charge ("RRRP") used by rate regulated distributors to bill their customers shall be .0005 per kilowatt-hour for electricity consumed after January 1, 2022. This unit rate shall apply to a customer's metered energy consumption adjusted by the distributor's Board-approved Total Loss Factor.

Embedded Generation Rate Rider

As part of PUC's 2018 COS Application (EB-2017-0071), the OEB approved an embedded generation rate rider refund of ($.0004/kWh) for all rate classes. This rate rider was to address the systematic over collection of the WMS and RRRP from customers relative to the obligation to the Independent Electricity System Operator ("IESO"). The over collection is driven, in part, by embedded generation for which PUC is not required to pay the WMS or RRRP to the IESO. The rate rider is calculated by calculating the forecasted energy from embedded generation. PUC has updated its forecast of embedded generation for this application to 78,372,260 kWh which is the most recent 5 year average of historical actual presented in Table 8-10.

Table 8-10: Historical Embedded Generation (in kWh)

Year	Embedded Generation	5 Year Moving Average
2012	78,154,102	
2013	70,733,589	
2014	67,412,356	
2015	76,318,882	
2016	68,431,934	72,210,173
2017	74,074,630	71,394,278
2018	82,762,000	73,799,960
2019	71,267,915	74,571,072
2020	80,485,738	75,404,443
2021	83,271,017	78,372,260

The forecasted amount of embedded generation of 78,372,260 kWh is divided by the WMS and RRRP charge to get the total credit to refund to customer as presented in Table 8-11.

Table 8-11: Calculation of WMS Credit to Customers (in kWh)

Calculation of WMS Credit to Customers	
Embedded Generation	78,372,260
WMS & RRRP	-0.0034
WMS credit to customers	(266,466)

This credit of ($266,466) is divided by the load forecast total kWh of consumption of 578,772,961 kWh to get a round rate rider refund of ($.0005) as shown in table 8-12 below. The actual credit due to round will be approximately $289,386.

Table 8-12: Embedded Generation Rate Rider Refund

Rate Class	Units	kWh	Allocated Group 1 Balance	Rate Rider for DVA Accounts	Actual Credit Due to Rounding
Residential	kWh	274,738,681	($126,489)	($0.0005)	($137,369)
GS<50	kWh	79,051,528	($36,395)	($0.0005)	($39,526)
GS>50	kWh	221,450,388	($101,955)	($0.0005)	($110,725)
USL	kWh	878,528	($404)	($0.0005)	($439)
Sentinel	kWh	193,841	($89)	($0.0005)	($97)
Street Light	kWh	2,459,994	($1,133)	($0.0005)	($1,230)
		578,772,961	($266,466)		($289,386)

8.5 SPECIFIC SERVICE CHARGES

PUC is proposing the current specific service charges be maintained in this application. PUC has followed the OEB Report on Wireline Pole Attachment Charges in its 2018 COS application and has continued to follow additional guidance released by the OEB on December 16, 2021. PUC is requesting disposition of a variance in account 1508 – Pole Attachment Variance which is explained further in Exhibit 9 Section 9.5.2.1. PUC has not forecasted an amount for disposition in 2022 as amounts are not final and PPUC will continue with this DVA account.

8.6 LOW VOLTAGE SERVICE RATES (WHERE APPLICABLE)

PUC does not charge any low voltage service rates.

8.7 SMART METER ENTITY CHARGE

The Independent Electricity System Operator, in its capacity as the Smart Metering Entity, filed an application for the 2023 - 2027 Smart Meter Charge with the OEB on March 31, 2022. The application and other documents which form the record of the proceeding are available on the OEB Website (EB-2022-0137). A Smart Metering Charge of $0.43 per meter per month has been proposed, a reduction from the currently approved Smart Metering Charge of $0.57 per meter per month. This charge is considered interim until a final decision is rendered. PUC has used the interim rate of $0.43 per meter per month in its application.

8.8 LOSS ADJUSTMENT FACTORS

PUC is not an embedded distributor. There have been no previous studies or recommendations by the OEB in previous decisions. PUC has calculated the total loss factor to be applied to customers' consumption based on the average wholesale and retail kWh for the years 2017 to 2021. The calculations are summarized in the following Table 8-13 which also consistent with calculations provided in Chapter 2 Appendix 2-R. The numbers reflected in this table match PUC's RRR filing for 2017-2021.

Table 8-13: Loss Factor Calculation

		Historical Years					5-Year Average
		2017	2018	2019	2020	2021	
	Losses Within Distributor's System						
A(1)	"Wholesale" kWh delivered to distributor (higher value)	652,970,471	666,736,298	660,423,172	640,745,749	628,757,114	649,926,561
A(2)	"Wholesale" kWh delivered to distributor (lower value)	652,970,471	666,736,298	660,423,172	640,745,749	628,757,114	649,926,561
B	Portion of "Wholesale" kWh delivered to distributor for its Large Use Customer(s)						-
C	Net "Wholesale" kWh delivered to distributor = **A(2) - B**	652,970,471	666,736,298	660,423,172	640,745,749	628,757,114	649,926,561
D	"Retail" kWh delivered by distributor	622,542,513	633,697,927	631,945,814	613,632,199	604,318,512	621,227,393
E	Portion of "Retail" kWh delivered by distributor to its Large Use Customer(s)						-
F	Net "Retail" kWh delivered by distributor = **D - E**	622,542,513	633,697,927	631,945,814	613,632,199	604,318,512	621,227,393
G	Loss Factor in Distributor's system = **C / F**	1.0489	1.0521	1.0451	1.0442	1.0404	1.0462
	Losses Upstream of Distributor's System						
H	Supply Facilities Loss Factor	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
	Total Losses						
I	Total Loss Factor = **G x H**	1.0489	1.0521	1.0451	1.0442	1.0404	1.0462

The following Table 8-14 provides the total loss factor for secondary and primary customers.

Table 8-14: Total Loss Factor

Total Loss Factors	
Supply Facility Loss Factor	**1.0000**
Distribution Loss Factor	
Distribution Loss Factor - Secondary Metered Customer < 5,000kW	**1.0462**
Distribution Loss Factor - Primary Metered Customer < 5,000kW	**1.0357**
Total Loss Factor	
Total Loss Factor - Secondary Metered Customer < 5,000kW	**1.0462**
Total Loss Factor - Primary Metered Customer < 5,000kW	**1.0357**

Materiality Analysis on Distribution Losses

PUC's 5-year average Loss Adjustment factor is 4.62%. Pursuant to the Filing Requirements, as the Distribution Loss Adjustment factor is less than 5.00%, PUC is not required to provide an explanation of, or justification for, its loss adjustment factor.

8.9 TARIFF OF RATES AND CHARGES

The current and proposed tariff of rates and charges are provided in Appendix B and Appendix C. For the current tariff of rates and charges from the current approved rate order for PUC Distribution dated March 24, 2022 (EB-2021-0054), please see Appendix B. For the proposed tariff of rates and charges please see Tab 5. Final Tariff Schedule from the following live Excel file "2023_Tariff_Schedule_and_Bill_Impact_Model" and see Appendix C.

The current definition of rate classes and the current terms and conditions of service has been maintained in this application. PUC completed an update to its conditions of service on June 30, 2022, and gave customers until August 1, 2022, to comment. There were no comments received by customers and PUC filed the update with the OEB on August 8, 2022.

8.10 REVENUE RECONCILIATION

Table 8-15 provides reconciliation between the revenue based on the PUC proposed distribution rates and the total base revenue requirement. The calculation of revenue under current rates is provided in Table 3-1 at section 2.3.1 of Exhibit 3.

Table 8-15: PUC Distribution Test Year Distribution Revenue Reconciliation

Rate Class	Customers/ Connections	Number of Customers/ Connections	Test Year Consumption		Proposed Rates			Revenues at Proposed Rates	Class Specific Revenue Requirement	Transformer Allowance Credit	Total	Difference
		Average	kWh	kW	Monthly Service Charge	Volumetric						
						kWh	kW					
Residential	Customers	30,340	274,738,681		$ 42.15	$ -		$ 15,345,972	$ 15,344,320		$ 15,344,320	-$ 1,652
General Service < 50 kW	Customers	3,400	79,051,528		$ 27.90	$ 0.0334		$ 3,778,641	$ 3,782,036		$ 3,782,036	$ 3,395
General Service 50 to 4,999 kW	Customers	344		547,687	$ 154.07		$ 9.0363	$ 5,517,868	$ 5,585,075	$ 67,200	$ 5,517,875	$ 6
Sentinel Lighting	Connections	317		566	$ 4.78		$ 44.6252	$ 43,452	$ 43,448		$ 43,448	-$ 4
Street Lighting	Connections	8,037		7,200	$ 1.84		$ 12.0191	$ 263,995	$ 263,810		$ 263,810	-$ 185
Unmetered Scattered Load	Customers	25	878,528		$ 17.09	$ 0.0516		$ 50,459	$ 50,446		$ 50,446	-$ 13
Total								$ 25,000,388	$ 25,069,135	$ 67,200	$ 25,001,935	$ 1,547

8.11 BILL IMPACT INFORMATION

PUC submits that the bill impacts of its proposed electricity distribution rates are reasonable and do not require rate mitigation. The total bill impacts for a PUC Residential RPP customer at the 10th consumption percentile is 6.18%. This impact is below the standard acceptable impact of 10.00% and therefore does not require further mitigation. Table 8-16 summarizes the bill impacts.

Table 8-16 Bill Impact Summary with SSG Savings

Bill Impacts			Total Bill Impacts		Distribution only Imacts	
Class	**Consumption (kWh)**	**Consumption (kW)**	**Total Bill Increase/Decrease**	**Total Bill Impact %**	**Total Distribution Bill Increase/ Decrease**	**Total Distribution Bill Impact %**
Residential	750	0	$3.16	2.59%	$5.67	15.79%
GS<50	2,000	0	-$1.40	-0.45%	$5.09	6.13%
GS>50	57,220	145	-$265.91	-2.84%	$190.24	15.28%
USL	3600	0	$9.17	1.58%	$26.29	15.27%
Sentinel Light	50	1.00	$6.34	13.13%	$6.61	15.77%
Street Light	199852	585	$2,184.67	5.28%	$3,912.43	21.15%

Appendix D to this Exhibit presents the results of the assessment of customer total bill impacts by level of consumption by rate class. Appendix D is consistent with Tab 6 - Bill Impacts from the following live Excel file “2023_Tariff_Schedule_and_Bill_Impact_Model”. Impacts are shown using the applicable current approved rates and the proposed PUC Distribution rates for distribution, including Rate Riders for the recovery of Deferral and Variance accounts discussed in Exhibit 9. These bill impacts also include the reduction of approximately 2.70% in VVO consumption savings from the SSGICM (EB-2018-0219 / EB-2020-0249). The rate impacts are assessed on the basis of moving to the proposed distribution rates.

8.12 RATE MITIGATION

PUC submits that the bill impacts of its proposed electricity distribution rates are reasonable and do not require rate mitigation. PUC has consulted with the one customer of the Sentinel Light Class and confirms that they are agreeable with this increase.

8.13 RATE HARMONIZATION MITIGATION ISSUES

PUC has not been a part of any MAADs transactions and therefore any rate harmonization issues are not applicable to PUC.

APPENDIX A

Retail Transmission Service Rate Work Form

Ontario Energy Board

v 1.0

2023 RTSR Workform for Electricity Distributors

Drop-down lists are shaded blue; Input cells are shaded green.

Utility Name	PUC Distribution Inc.
Assigned EB Number	EB-2022-0059
Name and Title of Contact	Tyler Kasubeck, Regulatory Financial Analyst
Phone Number	705-759-3009
Email Address	tyler.kasubeck@ssmpuc.com
Last COS Re-based Year	**2018**

Ontario Energy Board

v 1.0

2023 RTSR Workform for Electricity Distributors

Rate Class	Rate Description	Unit	Rate	Non-Loss Adjusted Metered kWh	Non-Loss Adjusted Metered kW	Applicable Loss Factor *eg: (1.0325)*	Loss Adjusted Billed kWh
RESIDENTIAL SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kWh	0.0086	292,491,184	0	1.0481	306,560,010
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kWh	0.0080	88,569,433	0	1.0481	92,829,623
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	3.2330	87,886,230	214,683	1.0481	92,113,558
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	4.0669	131,829,141	322,024	1.0481	138,170,122
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kWh	0.0080	877,918	0	1.0481	920,146
SENTINEL LIGHTING SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	2.4511	203,611	596	1.0481	213,404
STREET LIGHTING SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	2.4391	249,994	7,202	1.0481	262,019

Ontario Energy Board

v 1.0

2023 RTSR Workform for Electricity Distributors

Uniform Transmission Rates	Unit	2021 Jan to Jun	2021 Jul to Dec	2022	2023
Rate Description		Rate		Rate	Rate
Network Service Rate	kW	$ 4.67	$ 4.90	$ 5.13	$ 5.13
Line Connection Service Rate	kW	$ 0.77	$ 0.81	$ 0.88	$ 0.88
Transformation Connection Service Rate	kW	$ 2.53	$ 2.65	$ 2.10	$ 2.10

Hydro One Sub-Transmission Rates	Unit	2021	2022	2023
Rate Description		Rate	Rate	Rate
Network Service Rate	kW	$ 3.4778	4.3473	$ 4.3473
Line Connection Service Rate	kW	$ 0.8128	0.6788	$ 0.6788
Transformation Connection Service Rate	kW	$ 2.0458	2.3267	$ 2.3267
Both Line and Transformation Connection Service Rate	kW	$ 2.8586	3.0055	$ 3.0055

If needed, add extra host here. (I)	Unit	2021	2022	2023
Rate Description		Rate	Rate	Rate
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

If needed, add extra host here. (II)	Unit	2021	2022	2023
Rate Description		Rate	Rate	Rate
Network Service Rate	kW			
Line Connection Service Rate	kW			
Transformation Connection Service Rate	kW			
Both Line and Transformation Connection Service Rate	kW	$ -	$ -	$ -

		Historical 2021	Current 2022	Forecast 2023
Low Voltage Switchgear Credit (if applicable, enter as a negative value)	$			

Ontario Energy Board

v 1.0

2023 RTSR Workform for Electricity Distributors

In the green shaded cells, enter billing detail for wholesale transmission for the same reporting period as the billing determinants on Sheet "3. RRR Data". For Hydro One Sub-transmission Rates, if you are charged a combined Line and Transformation Connection rate, please ensure that both the Line Connection and Transformation Connection columns are completed. If any of the Hydro One Sub-transmission rates (column E, I and M) are highlighted in red, please double check the billing data entered in "Units Billed" and "Amount" columns. The highlighted rates do not match the Hydro One Sub-transmission rates approved for that time period. If data has been entered correctly, please provide explanation for the discrepancies in rates.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	107,975	$4.6700	504,243		$0.0000			$0.0000		$ -
February	108,561	$4.6700	506,980		$0.0000			$0.0000		$ -
March	105,073	$4.6700	490,691		$0.0000			$0.0000		$ -
April	87,429	$4.6700	408,293		$0.0000			$0.0000		$ -
May	64,144	$4.6700	299,552		$0.0000			$0.0000		$ -
June	72,483	$4.6700	338,496		$0.0000			$0.0000		$ -
July	69,449	$4.9000	340,300		$0.0000			$0.0000		$ -
August	74,032	$4.9000	362,757		$0.0000			$0.0000		$ -
September	68,321	$4.9000	334,773		$0.0000			$0.0000		$ -
October	73,309	$4.9000	359,214		$0.0000			$0.0000		$ -
November	95,200	$4.9000	466,480		$0.0000			$0.0000		$ -
December	106,596	$4.9000	522,320		$0.0000			$0.0000		$ -
Total	1,032,572	$ 4.78	$ 4,934,100	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.0000			$0.0000			$0.0000		$ -
February		$0.0000			$0.0000			$0.0000		$ -
March		$0.0000			$0.0000			$0.0000		$ -
April		$0.0000			$0.0000			$0.0000		$ -
May		$0.0000			$0.0000			$0.0000		$ -
June		$0.0000			$0.0000			$0.0000		$ -
July		$0.0000			$0.0000			$0.0000		$ -
August		$0.0000			$0.0000			$0.0000		$ -
September		$0.0000			$0.0000			$0.0000		$ -
October		$0.0000			$0.0000			$0.0000		$ -
November		$0.0000			$0.0000			$0.0000		$ -
December		$0.0000			$0.0000			$0.0000		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I) (if needed)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.0000			$0.0000			$0.0000		$ -
February		$0.0000			$0.0000			$0.0000		$ -
March		$0.0000			$0.0000			$0.0000		$ -
April		$0.0000			$0.0000			$0.0000		$ -
May		$0.0000			$0.0000			$0.0000		$ -
June		$0.0000			$0.0000			$0.0000		$ -
July		$0.0000			$0.0000			$0.0000		$ -
August		$0.0000			$0.0000			$0.0000		$ -
September		$0.0000			$0.0000			$0.0000		$ -
October		$0.0000			$0.0000			$0.0000		$ -
November		$0.0000			$0.0000			$0.0000		$ -
December		$0.0000			$0.0000			$0.0000		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II) (if needed)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January		$0.0000			$0.0000			$0.0000		$ -
February		$0.0000			$0.0000			$0.0000		$ -
March		$0.0000			$0.0000			$0.0000		$ -
April		$0.0000			$0.0000			$0.0000		$ -
May		$0.0000			$0.0000			$0.0000		$ -
June		$0.0000			$0.0000			$0.0000		$ -
July		$0.0000			$0.0000			$0.0000		$ -
August		$0.0000			$0.0000			$0.0000		$ -
September		$0.0000			$0.0000			$0.0000		$ -
October		$0.0000			$0.0000			$0.0000		$ -
November		$0.0000			$0.0000			$0.0000		$ -
December		$0.0000			$0.0000			$0.0000		$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	107,975	$4.6700	$ 504,243	-	$0.0000	$ -	-	$0.0000	$ -	$ -
February	108,561	$4.6700	$ 506,980	-	$0.0000	$ -	-	$0.0000	$ -	$ -
March	105,073	$4.6700	$ 490,691	-	$0.0000	$ -	-	$0.0000	$ -	$ -
April	87,429	$4.6700	$ 408,293	-	$0.0000	$ -	-	$0.0000	$ -	$ -
May	64,144	$4.6700	$ 299,552	-	$0.0000	$ -	-	$0.0000	$ -	$ -
June	72,483	$4.6700	$ 338,496	-	$0.0000	$ -	-	$0.0000	$ -	$ -
July	69,449	$4.9000	$ 340,300	-	$0.0000	$ -	-	$0.0000	$ -	$ -
August	74,032	$4.9000	$ 362,757	-	$0.0000	$ -	-	$0.0000	$ -	$ -
September	68,321	$4.9000	$ 334,773	-	$0.0000	$ -	-	$0.0000	$ -	$ -
October	73,309	$4.9000	$ 359,214	-	$0.0000	$ -	-	$0.0000	$ -	$ -
November	95,200	$4.9000	$ 466,480	-	$0.0000	$ -	-	$0.0000	$ -	$ -
December	106,596	$4.9000	$ 522,320	-	$0.0000	$ -	-	$0.0000	$ -	$ -
Total	1,032,572	$ 4.78	$ 4,934,100	-	$ -	$ -	-	$ -	$ -	$ -

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ -

Ontario Energy Board v 1.0

2023 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when current 2022 Uniform Transmission Rates and Hydro One Sub-transmission Rates are applied against historical 2021 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	107,975	$ 5.1300	$ 553,912	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
February	108,561	$ 5.1300	$ 556,918	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
March	105,073	$ 5.1300	$ 539,024	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
April	87,429	$ 5.1300	$ 448,511	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
May	64,144	$ 5.1300	$ 329,059	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
June	72,483	$ 5.1300	$ 371,838	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
July	69,449	$ 5.1300	$ 356,273	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
August	74,032	$ 5.1300	$ 379,784	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
September	68,321	$ 5.1300	$ 350,487	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
October	73,309	$ 5.1300	$ 376,075	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
November	95,200	$ 5.1300	$ 488,376	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
December	106,596	$ 5.1300	$ 546,837	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
Total	1,032,572	$ 5.13	$ 5,297,094	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Units Billed	Rate	Amount	Amount
January	107,975	$5.13	$ 553,912	-	$0.00	$ -	-	$0.00	$ -	$ -
February	108,561	$5.13	$ 556,918	-	$0.00	$ -	-	$0.00	$ -	$ -
March	105,073	$5.13	$ 539,024	-	$0.00	$ -	-	$0.00	$ -	$ -
April	87,429	$5.13	$ 448,511	-	$0.00	$ -	-	$0.00	$ -	$ -
May	64,144	$5.13	$ 329,059	-	$0.00	$ -	-	$0.00	$ -	$ -
June	72,483	$5.13	$ 371,838	-	$0.00	$ -	-	$0.00	$ -	$ -
July	69,449	$5.13	$ 356,273	-	$0.00	$ -	-	$0.00	$ -	$ -
August	74,032	$5.13	$ 379,784	-	$0.00	$ -	-	$0.00	$ -	$ -
September	68,321	$5.13	$ 350,487	-	$0.00	$ -	-	$0.00	$ -	$ -
October	73,309	$5.13	$ 376,075	-	$0.00	$ -	-	$0.00	$ -	$ -
November	95,200	$5.13	$ 488,376	-	$0.00	$ -	-	$0.00	$ -	$ -
December	106,596	$5.13	$ 546,837	-	$0.00	$ -	-	$0.00	$ -	$ -
Total	1,032,572	$ 5.13	$ 5,297,094	-	$ -	$ -	-	$ -	$ -	$ -

Low Voltage Switchgear Credit (if applicable)	$ -
Total including deduction for Low Voltage Switchgear Credit	$ -

Ontario Energy Board

v 1.0

2023 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate the expected billing when forecasted 2023 Uniform Transmission Rates and Hydro One Sub-transmission Rates are applied against historical 2021 transmission units.

IESO	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	107,975	$ 5.1300	$ 553,912	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
February	108,561	$ 5.1300	$ 556,918	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
March	105,073	$ 5.1300	$ 539,024	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
April	87,429	$ 5.1300	$ 448,511	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
May	64,144	$ 5.1300	$ 329,059	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
June	72,483	$ 5.1300	$ 371,838	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
July	69,449	$ 5.1300	$ 356,273	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
August	74,032	$ 5.1300	$ 379,784	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
September	68,321	$ 5.1300	$ 350,487	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
October	73,309	$ 5.1300	$ 376,075	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
November	95,200	$ 5.1300	$ 488,376	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
December	106,596	$ 5.1300	$ 546,837	-	$ 0.8800	$ -	-	$ 2.1000	$ -	$ -
Total	1,032,572	$ 5.13	$ 5,297,094	-	$ -	$ -	-	$ -	$ -	$ -

Hydro One	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
February	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
March	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
April	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
May	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
June	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
July	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
August	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
September	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
October	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
November	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
December	-	$ 4.3473	$ -	-	$ 0.6788	$ -	-	$ 2.3267	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (I)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Add Extra Host Here (II)	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
February	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
March	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
April	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
May	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
June	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
July	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
August	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
September	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
October	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
November	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
December	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -
Total	-	$ -	$ -	-	$ -	$ -	-	$ -	$ -	$ -

Total	Network			Line Connection			Transformation Connection			Total Connection
Month	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Units Billed**	**Rate**	**Amount**	**Amount**
January	107,975	$ 5.13	553,912	-	$ -	-	-	$ -	-	$ -
February	108,561	$ 5.13	556,918	-	$ -	-	-	$ -	-	$ -
March	105,073	$ 5.13	539,024	-	$ -	-	-	$ -	-	$ -
April	87,429	$ 5.13	448,511	-	$ -	-	-	$ -	-	$ -
May	64,144	$ 5.13	329,059	-	$ -	-	-	$ -	-	$ -
June	72,483	$ 5.13	371,838	-	$ -	-	-	$ -	-	$ -
July	69,449	$ 5.13	356,273	-	$ -	-	-	$ -	-	$ -
August	74,032	$ 5.13	379,784	-	$ -	-	-	$ -	-	$ -
September	68,321	$ 5.13	350,487	-	$ -	-	-	$ -	-	$ -
October	73,309	$ 5.13	376,075	-	$ -	-	-	$ -	-	$ -
November	95,200	$ 5.13	488,376	-	$ -	-	-	$ -	-	$ -
December	106,596	$ 5.13	546,837	-	$ -	-	-	$ -	-	$ -
Total	1,032,572	$ 5.13	$ 5,297,094	-	$ -	$ -	-	$ -	$ -	$ -

Low Voltage Switchgear Credit (if applicable) $ -

Total including deduction for Low Voltage Switchgear Credit $ -

Ontario Energy Board

v 1.0

2023 RTSR Workform for Electricity Distributors

The purpose of this sheet is to re-align the current RTS Network Rates to recover current wholesale network costs.

Rate Class	Rate Description	Unit	Current RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Current Wholesale Billing	Adjusted RTSR Network
RESIDENTIAL SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kWh	0.0086	306,560,010	0	2,636,416	48.7%	2,581,800	0.0084
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATIOI	Retail Transmission Rate - Network Service Rate	$/kWh	0.0080	92,829,623	0	742,637	13.7%	727,252	0.0078
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	3.2330	92,113,558	214,683	694,070	12.8%	679,692	3.1660
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	4.0669	138,170,122	322,024	1,309,639	24.2%	1,282,509	3.9826
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kWh	0.0080	920,146	0	7,361	0.1%	7,209	0.0078
SENTINEL LIGHTING SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	2.4511	213,404	596	1,461	0.0%	1,431	2.4003
STREET LIGHTING SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	2.4391	262,019	7,202	17,566	0.3%	17,202	2.3886

The purpose of this table is to update the re-aligned RTS Network Rates to recover future wholesale network costs.

Rate Class	Rate Description	Unit	Adjusted RTSR-Network	Loss Adjusted Billed kWh	Billed kW	Billed Amount	Billed Amount %	Forecast Wholesale Billing	Proposed RTSR-Network
RESIDENTIAL SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kWh	0.0084	306,560,010	0	2,581,800	48.7%	2,581,800	**0.0084**
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATIOI	Retail Transmission Rate - Network Service Rate	$/kWh	0.0078	92,829,623	0	727,252	13.7%	727,252	**0.0078**
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	3.1660	92,113,558	214,683	679,692	12.8%	679,692	**3.1660**
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	3.9826	138,170,122	322,024	1,282,509	24.2%	1,282,509	**3.9826**
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kWh	0.0078	920,146	0	7,209	0.1%	7,209	**0.0078**
SENTINEL LIGHTING SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	2.4003	213,404	596	1,431	0.0%	1,431	**2.4003**
STREET LIGHTING SERVICE CLASSIFICATION	Retail Transmission Rate - Network Service Rate	$/kW	2.3886	262,019	7,202	17,202	0.3%	17,202	**2.3886**

Ontario Energy Board

v 1.0

2022 RTSR Workform for Electricity Distributors

The purpose of this sheet is to calculate Low Voltage service rates based on a forecasted host distribution expense.

Low Voltage Charges

Host I

	2017	2018	2019	2020	2021	2022 Forecast	2023 Forecast	Forecast Methodology
Host Volume								
Host Charges								

Host II

	2017	2018	2019	2020	2021	2022 Forecast	2023 Forecast	Forecast Methodology
Host Volume								
Host Charges								

Instructions: The methodology of the test year forecast for host charges is at the distributor's discretion. Please provide a brief descriptor of the methodology used here, and a complete description with rationale in the filed evidence.
Regardless of the methodology chosen, please ensure that the Host Charges for the test year is completed for each host distributor.

Low Voltage Rates

Proposed Loss Factor 1.0410

Instructions: Please enter the rate class volumes consistent with the proposed load forecast, and proposed loss factor.
If Low Voltage charges are applied based on volumes uplifted for losses, please select Loss Adjusted Volume in cell J34

Rate Class	Unit	2023 Forecasted Volume	RTSR Connection Rate	Loss Adjusted Volume	RTSR Connection Revenue	Allocation	Allocated Low Voltage Charges	Loss Adjusted Volume	Low Voltage Rates
RESIDENTIAL SERVICE CLASSIFICATION	$/kWh			0	0	0.0%	0	0	0.0000

APPENDIX B

Current Tariff of Rates and Charges

Ontario Energy Board

Tariff Schedule and Bill Impacts Model

(2023 Cost of Service Filers)

Please wait as macro imports and formats your current tariff schedule

PUC Distribution Inc.

X

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2022

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2021-0054

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a single family unit, non-commercial. This can be a separately metered living accommodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning. Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	33.72
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	1.43
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$	1.09
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$	0.39
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kWh	0.0003
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until April 30, 2023 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$/kWh	(0.0010)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0086

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	22.32
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.95
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$	0.14
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$	0.26
Smart Metering Entity Charge - effective until December 31, 2022	$	0.57
Distribution Volumetric Rate	$/kWh	0.0268
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kWh	0.0003
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until April 30, 2023 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$/kWh	0.0001
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$/kWh	0.0003
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kWh	0.0011
Retail Transmission Rate - Netw ork Service Rate	$/kWh	0.0080

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly peak demand used for billing purposes over the past 12 months is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	123.27
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	5.24
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$	0.80
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$	1.41
Distribution Volumetric Rate	$/kW	7.2479
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kW	0.1286
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until April 30, 2023 Applicable only for Class B Customers	$/kW	(0.0234)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$/kW	0.0427
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$/kW	0.0832
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.3082
Retail Transmission Rate - Network Service Rate	$/kW	3.2337
Retail Transmission Rate - Network Service Rate - Interval Metered	$/kW	4.0669

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information documentation with regard to electrical demand/consumption of the proposed unmetered load. Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the Distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	13.67
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.58
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$	0.09
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$	0.16
Distribution Volumetric Rate	$/kWh	0.0412
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until April 30, 2023 Applicable only for Class B Customers	$/kWh	(0.0001)
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kWh	0.0003
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$/kWh	0.0003
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$/kWh	0.0005
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kWh	0.0018
Retail Transmission Rate - Netw ork Service Rate	$/kWh	0.0080

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential or General Service customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	3.83
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.16
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$	0.03
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$	0.04
Distribution Volumetric Rate	$/kW	35.7037
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until April 30, 2023 Applicable only for Class B Customers	$/kW	(0.0201)
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kW	0.1057
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$/kW	0.2160
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$/kW	0.4096
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	1.5182
Retail Transmission Rate - Network Service Rate	$/kW	2.4511

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.47
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$	0.06
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$	0.01
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$	0.02
Distribution Volumetric Rate	$/kW	9.6161
Rate Rider for Disposition of Global Adjustment Account (2022) - effective until April 30, 2023 Applicable only for Non-RPP Customers	$/kWh	0.0033
Rate Rider for Disposition of Deferral/Variance Accounts (2022) - effective until April 30, 2023	$/kW	0.1061
Rate Rider for Disposition of Capacity Based Recovery Account (2022) - effective until April 30, 2023 Applicable only for Class B Customers	$/kW	(0.0194)
Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation - effective from November 1, 2020 and effective until October 31, 2022	$/kW	0.0594
Rate Rider for Recovery of Incremental Capital (2020) - effective until the effective date of the next cost of service based rate order	$/kW	0.1103
Rate Rider for Recovery of Incremental Capital - effective until the effective date of the next cost of service based rate order	$/kW	0.4089
Retail Transmission Rate - Network Service Rate	$/kW	2.4391

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment - effective until	$/kWh	(0.0004)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month		
(effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection charge - at meter - during regular hours	$	65.00
Reconnection charge - at meter - after hours	$	185.00
Reconnection charge - at pole - during regular hours	$	185.00
Reconnection charge - at pole - after hours	$	415.00

Other

Special meter reads	$	30.00
Service call - customer-owned equipment		Time & Materials
Service call - after regular hours		Time & Materials
Temporary service - install & remove - overhead - no transformer		Time & Materials
Temporary service - install & remove - underground - no transformer		Time & Materials
Temporary service - install & remove - overhead - with transformer		Time & Materials
Specific charge for access to the power poles - $/pole/year		
Specific charge for access to the power poles - $/pole/year		
(with the exception of wireless attachments)	$	34.76
Removal of overhead lines - during regular hours		Time & Materials
Removal of overhead lines - after hours		Time & Materials
Roadway escort - after regular hours		Time & Materials

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	107.68
Monthly fixed charge, per retailer	$	43.08
Monthly variable charge, per customer, per retailer	$/cust.	1.07
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.64
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.64)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.54
Processing fee, per request, applied to the requesting party	$	1.07
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.31
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.15

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0481
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0385

APPENDIX C
Proposed Tariff of Rates and Charges

PUC Distribution Inc.

TARIFF OF RATES AND CHARGES

Effective and Implementation Date May 1, 2023

This schedule supersedes and replaces all previously approved schedules of Rates, Charges and Loss Factors

EB-2022-0059

RESIDENTIAL SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less where the electricity is used exclusively in a single family unit, non-commercial. This can be a separately metered living accommodation, town house, apartment, semi-detached, duplex, triplex or quadruplex with residential zoning. Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	42.15
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	0.68
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$	(0.74)
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2025	$	(0.69)
Smart Metering Entity Charge - effective until December 31, 2023	$	0.43
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kWh	0.0008
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2024	$/kWh	0.0002
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0021)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0084

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0005)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION

This classification applies to a non residential account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW. Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	27.90
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	1.49
Smart Metering Entity Charge - effective until December 31, 2023	$	0.43
Distribution Volumetric Rate	$/kWh	0.0334
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kWh	0.0008
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2025	$/kWh	(0.0008)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2024	$/kWh	(0.0014)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kWh	(0.0010)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0021)
Retail Transmission Rate - Network Service Rate	$/kWh	0.7800

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0005)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005

GENERAL SERVICE 50 TO 4,999 KW SERVICE CLASSIFICATION

This classification applies to a non residential account whose average monthly peak demand used for billing purposes over the past 12 months is equal to or greater than, or is forecast to be equal to or greater than, 50 kW but less than 5,000 kW. Class A and Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of WMS - Sub-account CBR Class B is not applicable to wholesale market participants (WMP), customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new Class B customers.

If included in the following listing of monthly rates and charges, the rate rider for the disposition of Global Adjustment is only applicable to non-RPP Class B customers. It is not applicable to WMP, customers that transitioned between Class A and Class B during the variance account accumulation period, or to customers that were in Class A for the entire period. Customers who transitioned are to be charged or refunded their share of the variance disposed through customer specific billing adjustments. This rate rider is to be consistently applied for the entire period to the sunset date of the rate rider. In addition, this rate rider is applicable to all new non-RPP Class B customers.
It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	154.07
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	21.48
Distribution Volumetric Rate	$/kW	9.0363
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kW	0.3352
Rate Rider for Disposition of Tax Loss Carry-forw ard - effective until April 30, 2025	$/kW	(0.1638)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0561)
Rate Rider for Disposition of LRAMVA - effective until April 30, 2024	$/kW	0.4819
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2025	$/kW	(0.4286)
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0021)
Retail Transmission Rate - Netw ork Service Rate	$/kW	3.1660
Retail Transmission Rate - Netw ork Service Rate - Interval Metered	$/kW	3.9826

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0005)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION

This classification applies to an account taking electricity at 750 volts or less whose average monthly peak demand is less than, or is forecast to be less than, 50 kW and the consumption is unmetered. Such connections include cable TV power packs, bus shelters, telephone booths, traffic lights, railway crossings, etc. The customer will provide detailed manufacturer information documentation with regard to electrical demand/consumption of the proposed unmetered load. Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the Distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	17.09
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	2.70
Distribution Volumetric Rate	$/kWh	0.0516
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kWh	0.0008
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2025	$/kWh	(0.0009)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kWh	(0.0001)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kWh	(0.0011)
Retail Transmission Rate - Network Service Rate	$/kWh	0.0078

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0005)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

SENTINEL LIGHTING SERVICE CLASSIFICATION

This classification applies to safety/security lighting with a Residential or General Service customer. This is typically exterior lighting, and unmetered. Consumption is estimated based on the equipment rating and estimated hours of use. Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	4.78
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	0.18
Distribution Volumetric Rate	$/kW	44.6252
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kW	0.3374
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2025	$/kW	(1.2481)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0480)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kW	0.1754
Retail Transmission Rate - Network Service Rate	$/kW	2.4003

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment	$/kWh	(0.0005)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

STREET LIGHTING SERVICE CLASSIFICATION

This classification applies to an account for roadway lighting with a Municipality, Regional Municipality, Ministry of Transportation and private roadway lighting operation, controlled by photo cells. The consumption for these customers will be based on the calculated connected load times the required lighting times established in the approved Ontario Energy Board street lighting load shape template. Class B consumers are defined on accordance with O. Reg. 429/04. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor’s Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable. In addition, the charges in the MONTHLY RATES AND CHARGES - Regulatory Component of this schedule do not apply to a customer that is an embedded wholesale market participant.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge (per connection)	$	1.84
Rate Rider for Disposition of Account 1509 - COVID - effective until April 30, 2024	$	0.04
Distribution Volumetric Rate	$/kW	12.0191
Rate Rider for Disposition of Deferral/Variance Accounts - effective until April 30, 2024	$/kW	0.2815
Rate Rider for Disposition of Tax Loss Carry-forward - effective until April 30, 2025	$/kW	(0.5957)
Rate Rider for Disposition of Capacity Based Recovery Account Applicable only for Class B Customers - effective until April 30, 2024	$/kW	(0.0479)
Rate Rider for Disposition of Group 2 Accounts - effective until April 30, 2024	$/kW	0.8293
Rate Rider for Disposition of Global Adjustment Account (2023) - Applicable only for Non-RPP Customers - effective until April 30, 2024	$/kWh	(0.0021)
Retail Transmission Rate - Network Service Rate	$/kW	2.3886

MONTHLY RATES AND CHARGES - Regulatory Component

Rate Rider for Embedded Generation Adjustment - effective until	$/kWh	(0.0005)
Wholesale Market Service Rate (WMS) - not including CBR	$/kWh	0.0030
Capacity Based Recovery (CBR) - Applicable for Class B Customers	$/kWh	0.0004
Rural or Remote Electricity Rate Protection Charge (RRRP)	$/kWh	0.0005
Standard Supply Service - Administrative Charge (if applicable)	$	0.25

microFIT SERVICE CLASSIFICATION

This classification applies to an electricity generation facility contracted under the Independent Electricity System Operator's microFIT program and connected to the distributor's distribution system. Further servicing details are available in the distributor's Conditions of Service.

APPLICATION

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

MONTHLY RATES AND CHARGES - Delivery Component

Service Charge	$	4.55

ALLOWANCES

Transformer Allowance for Ownership - per kW of billing demand/month	$/kW	(0.60)
Primary Metering Allowance for transformer losses - applied to measured demand and energy	%	(1.00)

SPECIFIC SERVICE CHARGES

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Customer Administration

Account set up charge/change of occupancy charge (plus credit agency costs if applicable)	$	30.00
Returned cheque (plus bank charges)	$	15.00
Legal letter charge	$	15.00
Meter dispute charge plus Measurement Canada fees (if meter found correct)	$	30.00

Non-Payment of Account

Late payment - per month (effective annual rate 19.56% per annum or 0.04896% compounded daily rate)	%	1.50
Reconnection charge - at meter - during regular hours	$	65.00
Reconnection charge - at meter - after hours	$	185.00
Reconnection charge - at pole - during regular hours	$	185.00
Reconnection charge - at pole - after hours	$	415.00

Other

Special meter reads	$	30.00
Service call - customer-owned equipment		Time & Materials
Service call - after regular hours		Time & Materials
Temporary service - install & remove - overhead - no transformer		Time & Materials
Temporary service - install & remove - underground - no transformer		Time & Materials
Temporary service - install & remove - overhead - with transformer		Time & Materials
Specific charge for access to the power poles - $/pole/year		
Specific charge for access to the power poles - $/pole/year (with the exception of wireless attachments)	$	34.76
Removal of overhead lines - during regular hours		Time & Materials
Removal of overhead lines - after hours		Time & Materials
Roadway escort - after regular hours		Time & Materials

RETAIL SERVICE CHARGES (if applicable)

The application of these rates and charges shall be in accordance with the Licence of the Distributor and any Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, which may be applicable to the administration of this schedule.

No rates and charges for the distribution of electricity and charges to meet the costs of any work or service done or furnished for the purpose of the distribution of electricity shall be made except as permitted by this schedule, unless required by the Distributor's Licence or a Code or Order of the Ontario Energy Board, and amendments thereto as approved by the Ontario Energy Board, or as specified herein.

Unless specifically noted, this schedule does not contain any charges for the electricity commodity, be it under the Regulated Price Plan, a contract with a retailer or the wholesale market price, as applicable.

It should be noted that this schedule does not list any charges, assessments, or credits that are required by law to be invoiced by a distributor and that are not subject to Ontario Energy Board approval, such as the Global Adjustment and the HST.

Retail Service Charges refer to services provided by a distributor to retailers or customers related to the supply of competitive electricity.

One-time charge, per retailer, to establish the service agreement between the distributor and the retailer	$	107.68
Monthly fixed charge, per retailer	$	43.08
Monthly variable charge, per customer, per retailer	$/cust.	1.07
Distributor-consolidated billing monthly charge, per customer, per retailer	$/cust.	0.64
Retailer-consolidated billing monthly credit, per customer, per retailer	$/cust.	(0.64)
Service Transaction Requests (STR)		
Request fee, per request, applied to the requesting party	$	0.54
Processing fee, per request, applied to the requesting party	$	1.07
Request for customer information as outlined in Section 10.6.3 and Chapter 11 of the Retail Settlement Code directly to retailers and customers, if not delivered electronically through the Electronic Business Transaction (EBT) system, applied to the requesting party		
Up to twice a year	$	no charge
More than twice a year, per request (plus incremental delivery costs)	$	4.31
Notice of switch letter charge, per letter (unless the distributor has opted out of applying the charge as per the Ontario Energy Board's Decision and Order EB-2015-0304, issued on February 14, 2019)	$	2.15

LOSS FACTORS

If the distributor is not capable of prorating changed loss factors jointly with distribution rates, the revised loss factors will be implemented upon the first subsequent billing for each billing cycle.

Total Loss Factor - Secondary Metered Customer < 5,000 kW	1.0462
Total Loss Factor - Primary Metered Customer < 5,000 kW	1.0357

APPENDIX D
Proposed Rates Bill Impacts

Customer Class:	RESIDENTIAL SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	750 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 33.72	1	$ 33.72	$ 42.15	1	$ 42.15	$ 8.43	25.00%
Distribution Volumetric Rate	$ -	750	$ -	$ -	730	$ -	$ -	
Fixed Rate Riders	$ 2.91	1	$ 2.91	$ (0.75)	1	$ (0.75)	$ (3.66)	-125.77%
Volumetric Rate Riders	$ (0.0010)	750	$ (0.75)	$ 0.0002	730	$ 0.15	$ 0.90	-119.47%
Sub-Total A (excluding pass through)			**$ 35.88**			**$ 41.55**	**$ 5.67**	**15.79%**
Line Losses on Cost of Power	$ 0.1031	36	$ 3.72	$ 0.1031	35	$ 3.57	$ (0.15)	-3.95%
Total Deferral/Variance Account Rate Riders	$ 0.0003	750	$ 0.23	$ 0.0008	730	$ 0.58	$ 0.36	159.47%
CBR Class B Rate Riders	$ (0.0001)	750	$ (0.08)	$ (0.0001)	730	$ (0.07)	$ 0.00	-2.70%
GA Rate Riders	$ -	750	$ -	$ -	730	$ -	$ -	
Low Voltage Service Charge	$ -	750	$ -		730	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.43	1	$ 0.43	$ 0.43	1	$ 0.43	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	750	$ (0.30)	$ (0.0005)	730	$ (0.36)	$ (0.06)	21.63%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 39.88**			**$ 45.69**	**$ 5.82**	**14.58%**
RTSR - Network	$ 0.0086	786	$ 6.76	$ 0.0084	763	$ 6.41	$ (0.35)	-5.14%
RTSR - Connection and/or Line and Transformation Connection	$ -	786	$ -	$ -	763	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 46.64**			**$ 52.11**	**$ 5.47**	**11.72%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	786	$ 2.67	$ 0.0034	763	$ 2.60	$ (0.08)	-2.88%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	786	$ 0.39	$ 0.0005	763	$ 0.38	$ (0.01)	-2.88%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	488	$ 39.98	$ 0.0820	474	$ 38.90	$ (1.08)	-2.70%
TOU - Mid Peak	$ 0.1130	128	$ 14.41	$ 0.1130	124	$ 14.02	$ (0.39)	-2.70%
TOU - On Peak	$ 0.1700	135	$ 22.95	$ 0.1700	131	$ 22.33	$ (0.62)	-2.70%
Total Bill on TOU (before Taxes)			**$ 127.29**			**$ 130.58**	**$ 3.29**	**2.59%**
HST	13%		$ 16.55	13%		$ 16.98	$ 0.43	2.59%
Ontario Electricity Rebate	17.0%		$ (21.64)	17.0%		$ (22.20)	$ (0.56)	
Total Bill on TOU			**$ 122.20**			**$ 125.36**	**$ 3.16**	**2.59%**

Customer Class:	GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	2,000 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 22.32	1	$ 22.32	$ 27.90	1	$ 27.90	$ 5.58	25.00%
Distribution Volumetric Rate	$ 0.0268	2000	$ 53.60	$ 0.0334	1946	$ 65.00	$ 11.40	21.26%
Fixed Rate Riders	$ 1.35	1	$ 1.35	$ 1.49	1	$ 1.49	$ 0.14	10.37%
Volumetric Rate Riders	$ 0.0029	2000	$ 5.80	$ (0.0032)	1946	$ (6.23)	$ (12.03)	-207.37%
Sub-Total A (excluding pass through)			**$ 83.07**			**$ 88.16**	**$ 5.09**	**6.13%**
Line Losses on Cost of Power	$ 0.1031	96	$ 9.92	$ 0.1031	90	$ 9.27	$ (0.65)	-6.54%
Total Deferral/Variance Account Rate Riders	$ 0.0003	2,000	$ 0.60	$ 0.0008	1,946	$ 1.56	$ 0.96	159.47%
CBR Class B Rate Riders	$ (0.0001)	2,000	$ (0.20)	$ (0.0001)	1,946	$ (0.19)	$ 0.01	-2.70%
GA Rate Riders	$ -	2,000	$ -	$ -	1,946	$ -	$ -	
Low Voltage Service Charge	$ -	2,000	$ -		1,946	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ 0.43	1	$ 0.43	$ 0.43	1	$ 0.43	$ -	0.00%
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	2,000	$ (0.80)	$ (0.0005)	1,946	$ (0.97)	$ (0.17)	21.63%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 93.02**			**$ 98.25**	**$ 5.23**	**5.62%**
RTSR - Network	$ 0.0080	2,096	$ 16.77	$ 0.0078	2,036	$ 15.88	$ (0.89)	-5.30%
RTSR - Connection and/or Line and Transformation Connection	$ -	2,096	$ -	$ -	2,036	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 109.79**			**$ 114.13**	**$ 4.34**	**3.95%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	2,096	$ 7.13	$ 0.0034	2,036	$ 6.92	$ (0.21)	-2.88%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	2,096	$ 1.05	$ 0.0005	2,036	$ 1.02	$ (0.03)	-2.88%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	1,300	$ 106.60	$ 0.0820	1,265	$ 103.72	$ (2.88)	-2.70%
TOU - Mid Peak	$ 0.1130	340	$ 38.42	$ 0.1130	331	$ 37.38	$ (1.04)	-2.70%
TOU - On Peak	$ 0.1700	360	$ 61.20	$ 0.1700	350	$ 59.55	$ (1.65)	-2.70%
Total Bill on TOU (before Taxes)			**$ 324.43**			**$ 322.97**	**$ (1.46)**	**-0.45%**
HST	13%		$ 42.18	13%		$ 41.99	$ (0.19)	-0.45%
Ontario Electricity Rebate	17.0%		$ (55.15)	17.0%		$ (54.91)	$ 0.25	
Total Bill on TOU			**$ 311.46**			**$ 310.05**	**$ (1.40)**	**-0.45%**

Customer Class:	**GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION**
RPP / Non-RPP:	**Non-RPP (Other)**
Consumption	**57,220 kWh**
Demand	**145 kW**
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 123.27	1	$ 123.27	$ 154.07	1	$ 154.07	$ 30.80	24.99%
Distribution Volumetric Rate	$ 7.2479	145	$ 1,050.95	$ 9.0363	141.085	$ 1,274.89	$ 223.94	21.31%
Fixed Rate Riders	$ 7.45	1	$ 7.45	$ 21.48	1	$ 21.48	$ 14.03	188.32%
Volumetric Rate Riders	$ 0.4341	145	$ 62.94	$ (0.1105)	141.085	$ (15.59)	$ (78.53)	-124.77%
Sub-Total A (excluding pass through)			**$ 1,244.61**			**$ 1,434.85**	**$ 190.24**	**15.28%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.1286	145	$ 18.65	$ 0.3352	141	$ 47.29	$ 28.64	153.62%
CBR Class B Rate Riders	$ (0.0234)	145	$ (3.39)	$ (0.0561)	141	$ (7.91)	$ (4.52)	133.27%
GA Rate Riders	$ 0.0021	57,220	$ 120.16	$ (0.0021)	55,675	$ (116.92)	$ (237.08)	-197.30%
Low Voltage Service Charge	$ -	145	$ -		141	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	57,220	$ (22.89)	$ (0.0005)	55,675	$ (27.84)	$ (4.95)	21.63%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 1,357.14**			**$ 1,329.47**	**$ (27.67)**	**-2.04%**
RTSR - Network	$ 3.2337	145	$ 468.89	$ 3.1660	141	$ 446.68	$ (22.21)	-4.74%
RTSR - Connection and/or Line and Transformation Connection	$ -	145	$ -	$ -	141	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 1,826.02**			**$ 1,776.14**	**$ (49.88)**	**-2.73%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	59,972	$ 203.91	$ 0.0034	58,247	$ 198.04	$ (5.87)	-2.88%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	59,972	$ 29.99	$ 0.0005	58,247	$ 29.12	$ (0.86)	-2.88%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
Average IESO Wholesale Market Price	$ 0.1036	59,972	$ 6,213.13	$ 0.1036	58,247	$ 6,034.41	$ (178.71)	-2.88%
Total Bill on Average IESO Wholesale Market Price			**$ 8,273.29**			**$ 8,037.97**	**$ (235.32)**	**-2.84%**
HST	13%		$ 1,075.53	13%		$ 1,044.94	$ (30.59)	-2.84%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Average IESO Wholesale Market Price			**$ 9,348.82**			**$ 9,082.91**	**$ (265.91)**	**-2.84%**

Customer Class:	UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION
RPP / Non-RPP:	RPP
Consumption	3,600 kWh
Demand	- kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 13.67	1	$ 13.67	$ 17.09	1	$ 17.09	$ 3.42	25.02%
Distribution Volumetric Rate	$ 0.0412	3600	$ 148.32	$ 0.0516	3503	$ 180.74	$ 32.42	21.86%
Fixed Rate Riders	$ 0.83	1	$ 0.83	$ 2.70	1	$ 2.70	$ 1.87	225.30%
Volumetric Rate Riders	$ 0.0026	3600	$ 9.36	$ (0.0020)	3503	$ (7.01)	$ (16.37)	-174.85%
Sub-Total A (excluding pass through)			**$ 172.18**			**$ 193.53**	**$ 21.35**	**12.40%**
Line Losses on Cost of Power	$ 0.1031	173	$ 17.85	$ 0.1031	162	$ 16.69	$ (1.17)	-6.54%
Total Deferral/Variance Account Rate Riders	$ 0.0003	3,600	$ 1.08	$ 0.0008	3,503	$ 2.80	$ 1.72	159.47%
CBR Class B Rate Riders	$ (0.0001)	3,600	$ (0.36)	$ (0.0001)	3,503	$ (0.35)	$ 0.01	-2.70%
GA Rate Riders	$ -	3,600	$ -	$ -	3,503	$ -	$ -	
Low Voltage Service Charge	$ -	3,600	$ -		3,503	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	3,600	$ (1.44)	$ (0.0005)	3,503	$ (1.75)	$ (0.31)	21.63%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 189.31**			**$ 210.92**	**$ 21.60**	**11.41%**
RTSR - Network	$ 0.0080	3,773	$ 30.19	$ 0.0078	3,665	$ 28.58	$ (1.60)	-5.30%
RTSR - Connection and/or Line and Transformation Connection	$ -	3,773	$ -	$ -	3,665	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 219.50**			**$ 239.50**	**$ 20.00**	**9.11%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	3,773	$ 12.83	$ 0.0034	3,665	$ 12.46	$ (0.37)	-2.88%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	3,773	$ 1.89	$ 0.0005	3,665	$ 1.83	$ (0.05)	-2.88%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	2,340	$ 191.88	$ 0.0820	2,277	$ 186.70	$ (5.18)	-2.70%
TOU - Mid Peak	$ 0.1130	612	$ 69.16	$ 0.1130	595	$ 67.29	$ (1.87)	-2.70%
TOU - On Peak	$ 0.1700	648	$ 110.16	$ 0.1700	631	$ 107.19	$ (2.97)	-2.70%
Total Bill on TOU (before Taxes)			**$ 605.66**			**$ 615.22**	**$ 9.55**	**1.58%**
HST	13%		$ 78.74	13%		$ 79.98	$ 1.24	1.58%
Ontario Electricity Rebate	17.0%		$ (102.96)	17.0%		$ (104.59)	$ (1.62)	
Total Bill on TOU			**$ 581.43**			**$ 590.61**	**$ 9.17**	**1.58%**

Customer Class:	**SENTINEL LIGHTING SERVICE CLASSIFICATION**
RPP / Non-RPP:	**RPP**
Consumption	**50** kWh
Demand	**1** kW
Current Loss Factor	**1.0481**
Proposed/Approved Loss Factor	**1.0462**

	Current OEB-Approved			**Proposed**			**Impact**	
	Rate ($)	**Volume**	**Charge ($)**	**Rate ($)**	**Volume**	**Charge ($)**	**$ Change**	**% Change**
Monthly Service Charge	$ 3.83	1	$ 3.83	$ 4.78	1	$ 4.78	$ 0.95	24.80%
Distribution Volumetric Rate	$ 35.7037	1	$ 35.70	$ 44.6252	1	$ 44.63	$ 8.92	24.99%
Fixed Rate Riders	$ 0.23	1	$ 0.23	$ 0.18	1	$ 0.18	$ (0.05)	-21.74%
Volumetric Rate Riders	$ 2.1438	1	$ 2.14	$ (1.0727)	1	$ (1.07)	$ (3.22)	-150.04%
Sub-Total A (excluding pass through)			**$ 41.91**			**$ 48.51**	**$ 6.61**	**15.76%**
Line Losses on Cost of Power	$ 0.1031	2	$ 0.25	$ 0.1031	2	$ 0.24	$ (0.01)	-3.95%
Total Deferral/Variance Account Rate Riders	$ 0.1057	1	$ 0.11	$ 0.3374	1	$ 0.34	$ 0.23	219.21%
CBR Class B Rate Riders	$ (0.0201)	1	$ (0.02)	$ (0.0480)	1	$ (0.05)	$ (0.03)	138.81%
GA Rate Riders	$ -	50	$ -	$ -	50	$ -	$ -	
Low Voltage Service Charge	$ -	1	$ -		1	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	50	$ (0.02)	$ (0.0005)	49	$ (0.02)	$ (0.00)	21.63%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 42.22**			**$ 49.02**	**$ 6.79**	**16.09%**
RTSR - Network	$ 2.4511	1	$ 2.45	$ 2.4003	1	$ 2.40	$ (0.05)	-2.07%
RTSR - Connection and/or Line and Transformation Connection	$ -	1	$ -	$ -	1	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 44.67**			**$ 51.42**	**$ 6.74**	**15.10%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	52	$ 0.18	$ 0.0034	52	$ 0.18	$ (0.00)	-0.18%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	52	$ 0.03	$ 0.0005	52	$ 0.03	$ (0.00)	-0.18%
Standard Supply Service Charge	$ 0.25	1	$ 0.25	$ 0.25	1	$ 0.25	$ -	0.00%
TOU - Off Peak	$ 0.0820	33	$ 2.67	$ 0.0820	32	$ 2.59	$ (0.07)	-2.70%
TOU - Mid Peak	$ 0.1130	9	$ 0.96	$ 0.1130	8	$ 0.93	$ (0.03)	-2.70%
TOU - On Peak	$ 0.1700	9	$ 1.53	$ 0.1700	9	$ 1.49	$ (0.04)	-2.70%
Total Bill on TOU (before Taxes)			**$ 50.28**			**$ 56.89**	**$ 6.60**	**13.13%**
HST	13%		$ 6.54	13%		$ 7.40	$ 0.86	13.13%
Ontario Electricity Rebate	17.0%		$ (8.55)	17.0%		$ (9.67)	$ (1.12)	
Total Bill on TOU			**$ 48.27**			**$ 54.61**	**$ 6.34**	**13.13%**

Customer Class:	STREET LIGHTING SERVICE CLASSIFICATION
RPP / Non-RPP:	Non-RPP (Retailer)
Consumption	199,852 kWh
Demand	585 kW
Current Loss Factor	1.0481
Proposed/Approved Loss Factor	1.0462

	Current OEB-Approved			Proposed			Impact	
	Rate ($)	Volume	Charge ($)	Rate ($)	Volume	Charge ($)	$ Change	% Change
Monthly Service Charge	$ 1.47	8037	$ 11,814.39	$ 1.84	8037	$ 14,788.08	$ 2,973.69	25.17%
Distribution Volumetric Rate	$ 9.6161	585	$ 5,625.42	$ 12.0191	585	$ 7,031.17	$ 1,405.76	24.99%
Fixed Rate Riders	$ 0.09	8037	$ 723.33	$ 0.04	8037	$ 321.48	$ (401.85)	-55.56%
Volumetric Rate Riders	$ 0.5786	585	$ 338.48	$ 0.4672	585	$ 273.31	$ (65.17)	-19.25%
Sub-Total A (excluding pass through)			**$ 18,501.62**			**$ 22,414.05**	**$ 3,912.43**	**21.15%**
Line Losses on Cost of Power	$ -	-	$ -	$ -	-	$ -	$ -	
Total Deferral/Variance Account Rate Riders	$ 0.1061	585	$ 62.07	$ 0.2815	585	$ 164.68	$ 102.61	165.32%
CBR Class B Rate Riders	$ (0.0194)	585	$ (11.35)	$ (0.0479)	585	$ (28.02)	$ (16.67)	146.91%
GA Rate Riders	$ 0.0033	199,852	$ 659.51	$ (0.0021)	194,456	$ (408.36)	$ (1,067.87)	-161.92%
Low Voltage Service Charge	$ -	585	$ -		585	$ -	$ -	
Smart Meter Entity Charge (if applicable)	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Fixed Rate Riders	$ -	1	$ -	$ -	1	$ -	$ -	
Additional Volumetric Rate Riders	$ (0.0004)	199,852	$ (79.94)	$ (0.0005)	194,456	$ (97.23)	$ (17.29)	21.63%
Sub-Total B - Distribution (includes Sub-Total A)			**$ 19,131.91**			**$ 22,045.12**	**$ 2,913.21**	**15.23%**
RTSR - Network	$ 2.4391	585	$ 1,426.87	$ 2.3886	585	$ 1,397.33	$ (29.54)	-2.07%
RTSR - Connection and/or Line and Transformation Connection	$ -	585	$ -	$ -	585	$ -	$ -	
Sub-Total C - Delivery (including Sub-Total B)			**$ 20,558.78**			**$ 23,442.45**	**$ 2,883.66**	**14.03%**
Wholesale Market Service Charge (WMSC)	$ 0.0034	209,465	$ 712.18	$ 0.0034	203,809	$ 692.95	$ (19.23)	-2.70%
Rural and Remote Rate Protection (RRRP)	$ 0.0005	209,465	$ 104.73	$ 0.0005	203,809	$ 101.90	$ (2.83)	-2.70%
Standard Supply Service Charge								
Non-RPP Retailer Avg. Price	$ 0.1036	209,465	$ 21,700.56	$ 0.1036	203,809	$ 21,114.65	$ (585.92)	-2.70%
Total Bill on Non-RPP Avg. Price			**$ 43,076.26**			**$ 45,351.95**	**$ 2,275.69**	**5.28%**
HST	13%		$ 5,599.91	13%		$ 5,895.75	$ 295.84	5.28%
Ontario Electricity Rebate	17.0%		$ -	17.0%		$ -		
Total Bill on Non-RPP Avg. Price			**$ 48,676.17**			**$ 51,247.70**	**$ 2,571.53**	**5.28%**

EXHIBIT 9

DEFERRAL AND VARIANCE ACCOUNTS

PUC Distribution Inc • EB-2022-0059 • Filed: August 31,2022

TABLE OF CONTENTS

LIST OF TABLES

EXHIBIT 9: DEFERRAL AND VARIANCE ACCOUNTS

9.1. DEFERRAL AND VARIANCE ACCOUNTS OVERVIEW

PUC Distribution Inc. ("PUC") has included in this Application, a request for approval for disposition of Group 1, Group 2 Deferral and Variance Account ("DVAs") and Uniform System of Accounts ("USoA") Account 1568 Lost Revenue Adjustment Mechanism Variance Account ("LRAMVA") balances as at December 31, 2021 and the forecasted interest through April 30, 2023. PUC has followed the Board's guidance in the *Accounting Procedures Handbook and FAQ's* ("APH") and related documents, and the Report of the Board on Electricity Distributors' Deferral and Variance Account Review Initiative ("EDDVAR Report"). PUC confirms that no adjustments have been made to DVA balances previously approved by the OEB on a final basis.

Table 9-1 provides a list of all the outstanding DVAs as at December 31, 2021. Table 9-2 provides a list of all outstanding DVAs being proposed for disposal, including forecasted principal, and carrying costs to April 30, 2023.

The balances in 1508 sub-accounts related to Incremental Capital Module ("ICM") applications submitted for Substation 16 ("Sub 16") and Sault Smart Grid ("SSG") projects will be moved to rate base in 2023. PUC is not requesting disposition of any residual balances in the 1508 Sub Accounts for Rate Riders collected from customers.

PUC confirms that it has used the DVAs in the same manner described in the APH. The Group 1 DVA balances presented in Table 9-1 reconcile with amounts on PUC's trial balance reported through the Electricity Reporting and Record-keeping Requirements ("RRR") and PUC's Audited Financial Statements. In addition, carrying charges are forecasted to April 30, 2023. The Group 2 DVAs are based on the December 31, 2021 audited balances, plus a forecast for the net principal transactions and carrying costs to April 30, 2023.

DVA Continuity Schedule

PUC has provided a continuity schedule of the Group 1 and Group 2 DVAs and LRAMVA in the live Excel format model named "2023_DVA_Continuity_Schedule_CoS" ("Model"). PUC has accepted the allocators as indicated in the EDDVAR Report. PUC accepts that it has relied on the default approach used by the 2023 DVA Continuity Schedule model including the customer class allocation rationale for each DVA account, the default proposed billing determinants including a charge type (fixed or variable) for recovery purposes, and the calculations of the rate riders. PUC confirms that it used the load data included in the Load Forecast section of the Application in the Model to calculate the DVA disposition rate riders.

Energy Sales & Cost of Power Balances

A breakdown of energy sales and cost of power expense balances, as reported in the Audited Financial Statements by PUC, is provided in Table 9-4. There are no differences between the reported energy sales and cost of power expenses.

Accounts not Requested for Disposition

PUC is not requesting to dispose of the residual balances in Account 1508 – ICM Substation 16 and Account 1508 – ICM SSG. PUC has followed the OEB Report of the Board: New Policy Options for the Funding of Capital Investments: The Advanced Capital Module (EB-2014-0219), released September 14, 2014 (the "ACM Report"). This section indicates the OEB will review the differences between actual ICM costs and amounts collected by the distributor, and determine at that time, based on materiality, whether any adjustment should be refunded or recovered by the distributor's rate payers. PUC has calculated the impact on account 1508 based on the approved incremental revenue requirement on actual spending and depreciation of the Sub 16 and SSG projects. These calculations resulted in non-material variances and therefore no disposal amounts are being requested. The details are provided in Exhibit 2, Section 2.8.1 and 2.8.2.

Carrying Charges

The forecasted interest on December 31, 2023 DVA balances is calculated using the Board's prescribed rate of 0.57% for the period of January 1, 2022 to March 31, 2022, 1.02% for the period April 1, 2023 to June 30, 2022 and 2.20% thereafter until April 30, 2023. The interest rates by quarter for each year are provided in Table 9-5 in this Exhibit.

OEB Commodity Pass Through Account Guidance

PUC confirms that it has complied with the OEB's February 21, 2019, guidance on the accounting for Accounts 1588 – RSVA Power and 1589 – RSVA Global Adjustment. PUC confirms that the balances being requested for disposition have been recorded in accordance with the aforementioned accounting guidance.

DVA Continue/Discontinue/Commence

PUC will continue or discontinue using the Group 2 accounts on a go-forward basis as outlined in Table 9-15 of this Exhibit. As well, PUC is requesting new sub-accounts in this Application, as set out in Table 9-15, to assist with the transactions related to its SSG project as outlined in section 9.7 below.

9.2. RECONCILIATION OF CONTINUITY SCHEDULE TO RRRS

Table 9-1 contains all DVA account balances from the 2021 Audited Financial Statements as at December 31, 2021. These balances agree to the 2021 year end balances in 2.1.7 Trial Balance of PUC's RRR filing on April 30, 2022. PUC confirms that no adjustments have been made to any DVA balances previously approved the OEB on a final basis. DVA Accounts were last disposed of on a final basis in PUC'S 2022 IRM Application for 2020 balances.

For Group 1 DVAs, a credit variance of $106,701 is calculated in the Model for account 1580, RSVA – Wholesale Market Service Charge, however, there is not an actual variance as the Model is double counting the CBR Class B balances.

PUC has used the DVAs in the same manner described in the APH and the Accounting Order approved with its SSG ICM application (EB-2018-0219/2020-0249) attached as Appendix A.

<u>Table 9-1: December 31, 2021 Audited Balances – DVAs</u>

Account Name	Account Number	Total Principal (Dec 31, 2021)	Total Interest (Dec 31, 2021)	Total Principal & Interest (Dec 31, 2021)	2.1.7 RRR Balances (Dec, 31, 2021)	Variance
Group 1 Accounts:						
Smart Metering Entity Charge Variance Account	1551	($16,762)	$53	($16,709)	($16,709)	$0
RSVA - Wholesale Market Service Charge	1580	$664,614	($8,090)	$656,524	$549,823	$106,701
RSVA - Wholesale Market Service Charge - CBR	1580	($106,072)	($630)	($106,701)	$0	($106,701)
RSVA - Retail Transmission Network Charge	1584	$685,423	$1,806	$687,230	$687,230	$0
RSVA - Power (excluding Global Adjustment)	1588	($718,815)	$6,969	($711,846)	($711,846)	($0)
RSVA - Global Adjustment	1589	$188,255	$24,535	$212,790	$212,790	$0
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	$25,811	$0	$25,811	$25,811	$0
Disposition and Recovery/Refund of Regulatory Balances (2019)	1595	($24,485)	$0	($24,485)	($24,485)	$0
Disposition and Recovery/Refund of Regulatory Balances (2020)	1595	$228,535	$0	$228,535	$228,535	$0
Subtotal - Group 1 Accounts		**$926,505**	**$24,644**	**$951,149**	**$951,149**	**($0)**
Group 2 Accounts:						
Other Regulatory Assets - Sub-Account - Pole Attachment Variance	1508	($25,567)	($1,165)	($26,732)	($26,732)	$0
Other Regulatory Assets - Sub-Account - ICM Substation 16	1508	$5,635,157	$1,389	$5,636,546	$5,636,546	$0
COVID-19 Rate Implementation Delay Variance Account	1509	$146,644	$0	$146,644	$146,644	$0
COVID-19 Incremental Expense Variance Account	1509	$383,029	$10,193	$393,221	$393,221	$0
Retail Cost Variance Account - Retail	1518	($5,273)	($915)	($6,188)	($6,188)	$0
Retail Cost Variance Account - STR	1548	$51,022	$2,373	$53,395	$53,395	$0
PILs & Taxes Variance	1592	($409,355)	($1,619)	($410,974)	($410,974)	$0
Subtotal - Group 2 Accounts		**$5,775,657**	**$10,255**	**$5,785,912**	**$5,785,912**	**$0**
Other Accounts:						
LRAM Variance Account	1568	$8,827	$5,436	$14,263	$14,263	$0
Subtotal - Other Accounts		**$8,827**	**$5,436**	**$14,263**	**$14,263**	**$0**
Total		**$6,710,988**	**$40,335**	**$6,751,324**	**$6,751,324**	**($0)**

9.3. ENERGY SALES AND COST OF POWER

For PUC, the sale of energy is a flow through revenue and the cost of power is a flow through expense. Energy sales and the cost of power expense, by component, are presented in Table 9-2 as reported in the Audited Financial Statements and the USoA within the RRR filing 2.1.7. PUC has no profit or loss resulting from the flow through of energy revenues and expenses. Any temporary variances are recorded in the Group 1 RSVA balances.

Table 9-2: Energy Revenue and Cost of Power Expenses

Account Name	Account Number	2017 Actual	2018 Actual	2019 Actual	2020 Actual	2021 Actual
ENERGY REVENUE:						
Residential Energy Sales	4006	($53,101,142)	($46,713,865)	($30,805,122)	($37,821,643)	($30,159,605)
Street Lighting Energy Sales	4025	($328,779)	($198,783)	($316,706)	($341,512)	($287,137)
Sentinel Energy Sales	4030	($23,255)	($19,380)	($21,128)	($29,928)	($23,526)
General Energy Sales	4035	($37,568,808)	($34,555,124)	($37,114,400)	($38,977,776)	($31,837,422)
Energy Sales for Resale	4055	($1,169,771)	($1,665,472)	($1,276,773)	($778,996)	($1,473,323)
Wholesale Market Service Charges	4062	($2,620,200)	($2,253,664)	($2,183,424)	($1,994,544)	($3,026,180)
Network	4066	($3,797,613)	($3,844,116)	($4,029,137)	($4,086,741)	($4,934,100)
Smart Meter Entity Charge	4076	($322,910)	($238,211)	($230,059)	($227,516)	($228,785)
TOTAL ENERGY REVENUE		**($98,932,478)**	**($89,488,616)**	**($75,976,750)**	**($84,258,657)**	**($71,970,078)**
COST OF POWER EXPENSES:						
Power Purchased	4705	$68,428,558	$61,672,851	$50,211,564	$56,117,835	$50,028,949
Global Adjustment	4707	$23,763,197	$21,479,774	$19,322,565	$21,832,021	$13,752,064
Wholesale Market Service	4708	$2,620,200	$2,253,664	$2,183,424	$1,994,544	$3,026,180
Network	4714	$3,797,613	$3,844,116	$4,029,137	$4,086,741	$4,934,100
Smart Meter Entity Charge Total	4751	$322,910	$238,211	$230,059	$227,516	$228,785
TOTAL COST OF POWER EXPENSES		**$98,932,478**	**$89,488,616**	**$75,976,750**	**$84,258,657**	**$71,970,078**
DIFFERENCE REVENUE VS EXPENSE		**$0**	**$0**	**($0)**	**($0)**	**$0**

9.4. INTEREST RATES APPLIED

PUC has used the Board’s prescribed interest rates when calculating carrying charges on the DVA balances. Table 9-3 below shows the Board’s prescribed interest rates starting from 2018 Q1 onward. Interest is calculated based on the opening monthly principal balances.

In accordance with the filing requirements, the most recent posted interest rate (2.2% for Q3 of 2022) has been used to forecast carrying charges to April 30, 2023. The interest component for DVA balances is included in the principal balance for each account.

Table 9-3: Interest Rates Applied to Deferral and Variance Accounts

Period	Interest Rate
Q1 2018	1.50%
Q2 2018	1.89%
Q3 2018	1.89%
Q4 2018	2.17%
Q1 2019	2.45%
Q2 2019	2.18%
Q3 2019	2.18%
Q4 2019	2.18%
Q1 2020	2.18%
Q2 2020	2.18%
Q3 2020	0.57%
Q4 2020	0.57%
Q1 2021	0.57%
Q2 2021	0.57%
Q3 2021	0.57%
Q4 2021	0.57%
Q1 2022	5.70%
Q2 2022	1.02%
Q3 2022 -2023 forecast	2.20%

9.5. DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS

PUC is requesting disposition of the variance accounts noted in Table 9-4 which summarizes the principal account balances in each DVA and sub-accounts for disposition. PUC is requesting a net disposition of $58,219 to be collected from customers, based on the 2021 year end balances plus 2022/2023 adjustments and interest from January 1, 2022 to April 30, 2023. Details of each account disposition request are discussed in detail in the evidence that follows.

The Group 1 balances differ from the RRR balances to account for the 2021 IRM disposal of 2020 DVA balances, as well as the forecasted interest to April 30, 2023. Group 2 balances differ from the RRR balances, as shown in tab. "3. Appendix A" in the Model. These differences are a result of PUC's request to dispose of principal balances for certain Group 2 accounts, up to and including April 30, 2023 activity, which the Model is unable to effectively accommodate. In order to incorporate this activity and associated carrying charges, PUC utilized column BF (Principal Adjustments during 2021) on tab "2b. Continuity Schedule" to input this information. The following summarizes the request for disposition of certain Group 2 accounts:

- For Account 1508, PUC calculated the difference between revenue requirement and the rate rider collected for its ICM projects as discussed in Exhibit 2. The difference has been determined to be immaterial and thus PUC is not requesting disposition of the residual balance. PUC had 2 ICMs during this period; Sub 16 [EB 2019-0170] and SSG [EB2020-0249/EB2018-0219].

  The reconciliation for the Sub 16 ICM includes account 1509 – ICM Rate Rider for Recovery of COVID-19 Forgone Revenue from Postponing Rate Implementation – effective November 1, 2020 until October 31, 2022. [EB 2019-0170]

- PUC is requesting to collect the difference between the calculated revenue and the actual collected rate rider in account 1509 – IRM Forgone Revenue Rate Rider which was due to the delayed implementation of May 1, 2020 rates to November 1, 2020. PUC has forecasted the rate rider to October 31, 2022. [EB 2019-0170]

- PUC is requesting to collect lost revenues from CDM activities from 2017-2022. The LRMAVA remaining balance from the 2018 COS is also included in this Application.

- PUC is requesting to refund the balance in account 1592 – PILs & Tax Variance CCA Changes. The 2021 CCA tax adjustment has been forecasted in include in the disposal amount.

Table 9-4: DVAs Requested for Disposal in 2023 Application

Account Name	Account Number	Total Principal & Interest (Dec 31, 2021)	2021 Disposal	COS Adjustments	Principal & Interest Disposed	Interest to April 30, 2023	Balances April 30, 2023 Total Claim
Group 1 Accounts:							
Smart Metering Entity Charge Variance Account	1551	($16,709)	$50	$0	($16,659)	($373)	($17,032)
RSVA - Wholesale Market Service Charge	1580	$656,524	$229,218	$0	$885,742	$19,790	$905,532
RSVA - Wholesale Market Service Charge - CBR	1580	($106,701)	$32,653	$0	($74,048)	($1,653)	($75,701)
RSVA - Retail Transmission Network Charge	1584	$687,230	($248,553)	$0	$438,677	$9,762	$448,439
RSVA - Power (excluding Global Adjustment)	1588	($711,846)	($170,617)	$0	($882,464)	($19,740)	($902,204)
RSVA - Global Adjustment	1589	$212,790	($552,595)	$0	($339,805)	($7,800)	($347,605)
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	$25,811	$0	$0	$25,811	$2,220	$28,031
Subtotal - Group 1 Accounts		**$951,149**	**($709,845)**	**$0**	**$37,255**	**$2,206**	**$39,461**
Account Name	**Account Number**	**Total Principal & Interest (Dec 31, 2021)**	**2023 Forecast Transactions**	**COS Adjustments**	**Principal & Interest Disposed**	**Interest to April 30, 2023**	**Total Claim**
Group 2 Accounts:							
Other Regulatory Assets - Sub-Account - Pole Attachments	1508	($26,732)	$0	$0	($26,732)	($570)	($27,302)
Other Regulatory Assets - Sub-Account - ICM Substation 16	1508	$6,020,119	$0	($6,020,119)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Substation 16 Rate Rider	1508	($268,431)	($344,181)	$612,612	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Substation Forgone Revenue	1508	($115,142)	$0	$115,142	$0	$0	$0
COVID-19 Delayed Implementation ICM Substation Forgone Revenue	1508	$115,142	$0	($115,142)	$0	$0	$0
COVID-19 Delayed Implementation ICM Substation Rate Rider	1508	($59,155)	($41,340)	$100,495	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid	1508	$0	$21,514,534	($21,514,534)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Rate Rider	1508	$0	($871,634)	$871,634	$0	$0	$0
COVID-19 Delayed Implementation IRM Forgone Revenue	1509	$192,359	$0	$0	$192,359	$4,291	$196,650
COVID-19 Delayed Implementation IRM Rate Rider Recovery	1509	($101,703)	($78,445)	$0	($180,147)	($1,756)	($181,903)
COVID-19 Incremental Expense Variance Account	1509	$393,222	$0	$0	$393,222	$8,545	$401,767
Retail Cost Variance Account - Retail	1518	($6,188)	($12,107)	$0	($18,295)	($388)	($18,683)
Retail Cost Variance Account - STR	1548	$53,395	$10,433	$0	$63,828	$1,371	$65,199
PILs & Taxes Variance	1592	($410,974)	($189,219)	$0	($600,193)	($13,353)	($613,546)
Subtotal - Group 2 Accounts		**$5,785,912**	**$19,988,042**	**($25,949,912)**	**($175,959)**	**($1,859)**	**($177,818)**
Other Accounts:							
LRAM Variance Account (2018 COS)	1568	$14,263	($22,841)	$0	($8,578)	($645)	($9,223)
LRAM Variance Account (2023 COS)	1568	$0	$201,460	$0	$201,460	$4,339	$205,799
Subtotal - Other Accounts		**$14,263**	**$178,619**	**$0**	**$192,882**	**$3,694**	**$196,576**
Total Group 2 Accounts		**$5,800,175**	**$20,166,661**	**($25,949,912)**	**$16,923**	**$1,835**	**$18,758**
Total		**$6,751,323**	**$19,456,816**	**($25,949,912)**	**$54,178**	**$4,041**	**$58,219**

Table 9-5 below summarizes the dates for principal activity that PUC is requesting to include/exclude in its Group 2 disposition by account.

Table 9-5: Principal Activity included/excluded in Group 2 Disposition

Group 2 Account Description	Account Number	Principal Amounts Included in Proposed Disposition
Group 2 Accounts:		
Other Regulatory Assets - Sub-Account - Pole Attachments	1508	to December 31, 2021
COVID-19 Delayed Implementation IRM Forgone Revenue	1509	to October 31, 2022
COVID-19 Delayed Implementation IRM Rate Rider Recovery	1509	to October 31, 2022
COVID-19 Incremental Expense Variance Account	1509	to December 31, 2021
Retail Cost Variance Account - Retail	1518	to April 30, 2023
Retail Cost Variance Account - STR	1548	to April 30, 2023
PILs & Taxes Variance	1592	to December 31, 2022
LRAM Variance Account (2018 COS)	1568	to December 31, 2021
LRAM Variance Account (2023 COS)	1568	to April 30, 2022
Group 2 Account Description	**Account Number**	**Principal Amounts Included in Proposed Disposition**
Other Regulatory Assets - Sub-Account - ICM Substation 16	1508	to December 31, 2021
Other Regulatory Assets - Sub-Account - ICM Substation 16 Rate Rider	1508	to April 30, 2023
Other Regulatory Assets - Sub-Account - ICM Substation Forgone Revenue	1508	to October 31, 2022
COVID-19 Delayed Implementation ICM Substation Forgone Revenue	1509	to October 31, 2022
COVID-19 Delayed Implementation ICM Substation Rate Rider	1509	to October 31, 2022
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid	1508	to December 31, 2021
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Rate Rider	1508	to April 30, 2023

9.5.1 Request of Disposal of Group 1 DVAs

PUC last disposed of Group 1 account balances in its 2022 IRM Rate Application (EB-2021-0054) on a final basis. PUC has entered the continuity data into Tab 2 of the Model from January 1, 2021 onwards. A total variance is calculated in tab “2a. Continuity Schedule” of the model. The 2022 IRM approved disposal for 2021 balances is shown below in Table 9-6 below, as well as the forecasted interest to April 30, 2023.

The rate riders are calculated in the Model in tab "7. Rate Rider Calculations." PUC has adopted the standard OEB model and has not made any edits or changes to the model, except to input RRR 2021 balances which were not yet pre-populated in the model.

PUC is requesting to dispose of the aggregated debit balance of $39,461 in its Group 1 DVAs, over a 12-month period.

Table 9-6: Group 1 DVAs Requested for Disposal

Account Name	Account Number	Principal & Interest Disposed	Interest to April 30, 2023	Balances April 30, 2023 Total Claim
Group 1 Accounts:				
Smart Metering Entity Charge Variance Account	1551	($16,659)	($373)	($17,032)
RSVA - Wholesale Market Service Charge	1580	$885,742	$19,790	$905,532
RSVA - Wholesale Market Service Charge - CBR	1580	($74,048)	($1,653)	($75,701)
RSVA - Retail Transmission Network Charge	1584	$438,677	$9,762	$448,439
RSVA - Power (excluding Global Adjustment)	1588	($882,464)	($19,740)	($902,204)
RSVA - Global Adjustment	1589	($339,805)	($7,800)	($347,605)
Disposition and Recovery/Refund of Regulatory Balances (2018)	1595	$25,811	$2,220	$28,031
Subtotal - Group 1 Accounts		**$37,255**	**$2,206**	**$39,461**

9.5.1.1 Account 1551: Smart Metering Entity Charge Variance Account

This account is used to record the difference between the Smart Meter Entity amounts billed to PUC customers and the charges paid to the IESO. PUC uses the accrual method. Account balances to December 31, 2021, plus carrying costs are being requested. The Board prescribed interest rates are used to calculate carrying charges.

PUC requests disposition of Account 1551 for the amount of $17,032 as a refund to customers, including carrying charges to April 30, 2023.

9.5.1.2 Account 1580: RSVA – Wholesale Market Service Charge

This account is used to record the difference between the amounts charged by the IESO for wholesale market services and the amount billed to PUC customers using the Board Approved rates. PUC uses the accrual method. The Board prescribed interest rates are used to calculate carrying charges. This account has been split into its sub-accounts for CBR Class B.

PUC requests disposition of Account 1580 for the amount of $905,532 to be collected from customers, including interest to April 30, 2022 and disposition of Account 1580 sub-account CBR Class B in the amount of $75,701 as a refund to customers, including interest to April 30, 2022.

9.5.1.3 Account 1584: RSVA – Retail Transmission Network Charge

This account is used to record the net of the amount charged by the IESO for transmission network services (based on the settlement invoice) and the amount billed to customers using the OEB-approved Retail Transmission Rate for network services. PUC uses the accrual method. The Board prescribed interest rates are used to calculate carrying charges.

PUC requests disposition of Account 1584 for the amount of $448,432 to be collected from customers, including interest to April 30, 2022.

9.5.1.4 Account 1588: RSVA – Power (excluding Global Adjustment)

This account is used to recover the net difference between the energy amount billed to customers and the energy charged to PUC using the settlement invoice from the IESO. PUC uses the accrual method. The Board prescribed interest rates are used to calculate carrying charges.

PUC requests disposition of Account 1588 for the amount of $902,204 as a refund to customers, including interest to April 30, 2022.

9.5.1.5 Account 1589: RSVA – Global Adjustment

This account is used to recover the net difference between the provincial benefit amount billed to non-RPP customers and the GA adjustment charge to PUC using the settlement invoice from the IESO. PUC uses the accrual method. The Board prescribed interest rates are used to calculate carrying charges.

PUC requests disposition of Account 1589 for the amount of $347,605 as a refund to non-RPP customers, including interest to April 30, 2022.

PUC confirms that the OEB guidance of February 21, 2019 on the accounting for accounts 1588 and 1589 has been followed. PUC further confirms that the IESO Global Adjustment Charge CT 148 is pro-rated into the Regulated Price Plan ("RPP") and Non-RPP portions.

9.5.1.6 GA Analysis Work Form

PUC has provided the GA Analysis Workform (the "Workform") for 2021 as a live excel spreadsheet file "2023-GA_Analysis_Workform_ 20220831". PUC acknowledges that the amounts in column F in the "GA 2021" tab are actual billed at the effective rate and therefore no unbilled current/previous month adjustments are required in column D or E.

In the Workform, PUC confirms the following information:

- The unresolved difference as a percentage of Expected GA Payments to IESO is less than 1.0%;

- No principal adjustments are required to be made in 2021; and
- The total activity in 2021 for account 1588 RSVA Power is 1.4%, however, the amount includes a CT2148 prior year amounts. Excluding this amount, it would be 0.6%, less than 1.0% of the total power purchased in account 4705 – Power purchased net a 2020 prior year adjustment GA charge by IESO invoiced in 2021.

9.5.1.7 Account 1595: (2018) Disposition and Recovery/Refund of Regulatory Balances

This account includes the regulatory asset or liability balances authorized by the Board for recovery in rates or payments/credits made to customers. Separate sub-accounts are maintained for expenses, interest, and recovery amounts for each Board-approved recovery. The amount requested for disposition below relates to residual balances from rate riders that concluded in 2018 or prior years.

PUC requests disposition of Account 1595 for $28,031 to be collected from customers from the 2018 sub-account. The Group 1 DVA Rate Rider approved in PUC's 2018 COS Application has a sunset date of April 30, 2020. PUC had no subsequent activity in this account other than a reconciliation adjustment between Account 1595 (2019) to correct balances between disposal years. PUC expects no further activity to this account and requests final disposal of the residual balance. The collections/returns variance percentage is less than 1.0%. PUC has provided the 1595 Analysis Workform sub-account (2018) as a live excel spreadsheet file "2023_1595_Analysis_Workform_20220831".

9.5.2 Request of Disposal of Group 2 DVAs

PUC's Group 2 accounts include the pole attachment variance, retail service charges variance, delayed IRM rate implementation forgone revenue rider reconciliation, PILS accelerated CCA variance, impacts arising from the COVID-19 emergency incremental variance, and the LRAM variance which have been accumulating since PUC's last 2018 COS request for disposition.

The total disposition amount for the Group 2 and other accounts is $18,758 as shown in Table 9-7 below. The following sections provide details of the Group 2 and other accounts utilized by PUC and the respective disposition requests. PUC discusses each of the Group 2 DVA Accounts below explaining the composition of the balance of each of the accounts requested for disposal.

Table 9-7: Group 2 DVAs Requested for Disposal

Account Name	Account Number	Total Principal & Interest (Dec 31, 2021)	2023 Forecast Transactions	COS Adjustments	Principal & Interest Disposed	Interest to April 30, 2023	Total Claim
Group 2 Accounts:							
Other Regulatory Assets - Sub-Account - Pole Attachments	1508	($26,732)	$0	$0	($26,732)	($570)	($27,302)
Other Regulatory Assets - Sub-Account - ICM Substation 16	1508	$6,021,509	$0	($6,021,509)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Substation 16 Rate Rider	1508	($269,820)	($338,395)	$608,215	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Substation Forgone Revenue	1508	($115,142)	$0	$115,142	$0	$0	$0
COVID-19 Delayed Implementation ICM Substation Forgone Revenue	1508	$115,142	$0	($115,142)	$0	$0	$0
COVID-19 Delayed Implementation ICM Substation Rate Rider	1508	($59,155)	($43,430)	$102,585	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid	1508	$0	$21,514,534	($21,514,534)	$0	$0	$0
Other Regulatory Assets - Sub-Account - ICM Sault Smart Grid Rate Rider	1508	$0	($871,634)	$871,634	$0	$0	$0
COVID-19 Delayed Implementation IRM Forgone Revenue	1509	$192,359	$0	$0	$192,359	$4,291	$196,650
COVID-19 Delayed Implementation IRM Rate Rider Recovery	1509	($101,703)	($78,445)	$0	($180,147)	($1,756)	($181,903)
COVID-19 Incremental Expense Variance Account	1509	$393,222	$0	$0	$393,222	$8,545	$401,767
Retail Cost Variance Account - Retail	1518	($6,188)	($12,107)	$0	($18,295)	($388)	($18,683)
Retail Cost Variance Account - STR	1548	$53,395	$10,433	$0	$63,828	$1,371	$65,199
PILs & Taxes Variance	1592	($410,974)	($189,219)	$0	($600,193)	($13,353)	($613,546)
Subtotal - Group 2 Accounts		**$5,785,912**	**$19,991,738**	**($25,953,609)**	**($175,959)**	**($1,859)**	**($177,818)**
Other Accounts:							
LRAM Variance Account (2018 COS)	1568	$14,263	($22,841)	$0	($8,578)	($645)	($9,223)
LRAM Variance Account (2023 COS)	1568	$0	$201,460	$0	$201,460	$4,339	$205,799
Subtotal - Other Accounts		**$14,263**	**$178,619**	**$0**	**$192,882**	**$3,694**	**$196,576**
Total Group 2 Accounts		**$5,800,175**	**$20,170,357**	**($25,953,609)**	**$16,923**	**$1,835**	**$18,758**

9.5.2.1 Account 1508: Pole Attachment Variance

The OEB provided accounting guidance in its letter dated July 20, 2018, "Accounting Guidance on Wireline Pole Attachment Charges. A new variance account, Account 1508 – Sub-Account Pole Attachment Revenue Variance was established to record the incremental revenue arising from the changes to the pole attachment charge. On December 16, 2021[1], the OEB issued an Order, establishing a new pole attachment charge for 2022 in accordance with the methodology outlined in O. Reg. 842/21. The Order also made the 2021 pole attachment charge final, which was previously established on an interim basis.

In 2018, the pole attachment charge was initially updated from $22.35 to $28.09 for September 1, 2018 until December 31, 2018 and adjusted to the OEB rate of $43.63 effective January 1, 2019. The rate was again adjusted to $44.50 on January 1, 2020.

In 2018, PUC recorded the incremental variance for the September to December period of 2018 in the amount of $25,567. PUC had its pole attachment rate updated with approval of its 2018 COS application and therefore has not calculated any further variance beyond 2018. The balance at December 31, 2021, with carrying charges to April 1, 2023 is $27,302 and is requested for disposition in this application. PUC has not included any additional variance for 2022 in this Application as amounts are unknow at this time. Table 9-8 below identifies the amounts in this account and total balance proposed for disposal.

[1] OE Letter, December 16, 2021, "Accounting Guidance for Wireline Pole Attachment Charges"

Table 9-8: Account 1508 (Poles) Disposal

Acct 1508- Pole	2018	2019	2020	2021	01-Apr-23
Opening	$ -	$ 25,567	$ 25,567	$ 25,567	$ 25,567
4210	$ 25,567				
Closing	$ 25,567	$ 25,567	$ 25,567	$ 25,567	$ 25,567
Carrying costs				$ 1,165	$ 1,735
Balance				$ 26,732	**$ 27,302**
Joint Poles	17,817				
Rate Jan-Aug	$ 22.35				
Rate Sept-Dec	$ 28.09				
Annual change	$ 5.74				
/ 4 mths	**$ 25,567**				

9.5.2.2 Account 1508: ICM Substation 16 Variance

As part of its 2020 IRM, PUC received approval for the incremental spending for its Sub 16 rebuild project. PUC used an account 1508 sub-account to record costs associated with the Sub 16 project.

PUC's reconciliation of the Sub 16 ICM actual revenue requirement versus the associated rate rider is provided in Exhibit 2, Section 2.8.1 – Addition of Previously Approved ICM Project Assets to Rate Base. The rate rider associated with this account will expire on April 30, 2023 and as such, amounts have been forecasted. The projected variance is not material; therefore, PUC is not requesting an amount for disposal. PUC is requesting that the account be discontinued.

9.5.2.3 Account 1508 – ICM Sault Smart Grid Variance

As part of its 2019 IRM (further amended and restated in 2020), PUC received approval for incremental spending for its SSG project. PUC used account 1508 sub-account to record costs associated with the approved SSG ICM. PUC received approval for a separate accounting order attached as Appendix-A. Since the project is currently being completed, PUC intends to follow this accounting order for the transactions that will occur by December 31, 2022 as outlined in the accounting order.

PUC's reconciliation of the SSG ICM forecasted revenue requirement versus the associated rate rider is provided in Exhibit 2, Section 2.8.2 – Addition of Previously Approved ICM Project Assets to Rate Base. The rate rider associated with this account will expire on April 30, 2023 and as such, amounts have been forecasted. The variance is not material; therefore, PUC is not requesting an amount for disposal. PUC is requesting that the account be discontinued.

9.5.2.4 Account 1518: Retail Service Charges and Account 1548: RCVA STR

With forecasted amounts to April 30, 2023, PUC requests to dispose of $18,683 to be refunded to customers and $65,199 to be collected from customers, in account 1518 – RSVA Retail and account 1548 – RSVA STR, respectively.

PUC confirms that all costs incorporated into the variances reported are incremental costs of providing retail services. The driver for the balances is the difference between the amounts collected from retailers to process retailer transactions and services agreements and the costs of providing those services. The balances are not material. PUC has provided Table 9-9 identifying all revenues and expenses listed by account that are incorporated into the variances recorded in account 1518 and account 1548. PUC has followed Article 490, Retail Services and Settlement Variances of the APH for account 1518 and account 1548.

PUC requests disposition of the balances in account 1518 – RCVA Retail and account 1548 – RCVA STR in this Application and to discontinue these accounts after April 1, 2023 on the assumption that PUC's 2023 rates are approved effective May 1, 2023. PUC has forecasted activity for 2022 through to April 30, 2023 based on historical averages for the past 2 years of activity.

Table 9-9: Account 1518 and 1548 (RSVA Retail) Disposal

Acct 1518	2017	2018	2019	2020	2021	Forecast to April 1, 2023
Opening	$ (139,578)	$ (123,129)	$ 24,370	$ 18,941	$ 4,005	$ (5,273)
4082	$ (18,458)	$ (17,492)	$ (25,442)	$ (26,764)	$ (21,816)	$ (24,290)
5315	$ 34,907	$ 25,412	$ 20,013	$ 11,828	$ 12,538	$ 12,183
Disposal		$ 139,578				
Closing	$ (123,129)	$ 24,370	$ 18,941	$ 4,005	$ (5,273)	$ (17,380)
Carrying costs					$ (915)	$ (1,303)
Balance					$ (6,187)	**$ (18,682)**
Acct 1548	**$ 2,017**	**$ 2,018**	**$ 2,019**	**$ 2,020**	**$ 2,021**	**$ 2,021**
Opening	$ 78,206	$ 89,176	$ 21,242	$ 30,157	$ 41,221	$ 51,023
4084	$ (126)	$ (118)	$ (220)	$ (236)	$ (130)	$ (183)
5315	$ 11,096	$ 10,389	$ 9,135	$ 11,300	$ 9,932	$ 10,616
Disposal		$ (78,206)				
Closing	$ 89,176	$ 21,242	$ 30,157	$ 41,221	$ 51,023	$ 61,455
Carrying costs					$ 2,373	$ 3,744
Balance					$ 53,395	**$ 65,199**

9.5.2.5 Account 1509: COVID-19 Delayed Implementation IRM Forgone Revenue Variance

On August 6, 2020, the OEB issued an Accounting Order[2], a COVID-19 Forgone Revenue Rate Rider Model, and associated filing instructions and account guidance for those utilities that wished to seek recovery of forgone revenue, the implementation of their 2020 rate increase, or both. In this Accounting Order, the OEB established a new sub-account under the Impacts Arising from the COVID-19 Emergency Account, called the Forgone Revenues from Postponing Rate Implementation Sub-Account. The OEB advised that this new sub-account was to be used to record forgone revenues due to the postponement of rate implementation as a result of the COVID-19 emergency.

[2] OEB's August 6, 2020 Accounting Order for the Establishment of a Sub-account to Record Impacts Arising from the COVID-19 Emergency for Forgone Revenues from Postponing Rate Implementation

The OEB Letter re: guidance for Electricity Distributors with Forgone revenues due to postponed rate implementation from COVID-19 provided that distributors that postponed their IRM decisions for May 1, 2020 rates must use the COVID-19 Forgone Revenue Rate Rider Model and Forgone Revenue Guidance when requesting recovery of forgone revenues through the OEB's administrative process as described in the Forgone Revenue Guidance.

PUC elected to delay the implementation of its 2020 IRM Rates. Therefore, PUC has provided the OEB with its forgone revenue model and its calculations for the forgone revenue rate rider and tariff charges as part of the COVID-19 Forgone Revenue Rate Rider model. The rate rider was effective November 1, 2020 to October 31, 2022.

Table 9-10 shows the forecasted foregone revenue of $212,221. PUC recalculated the actual foregone revenue based on actual consumption which updated the amount to $192,359. PUC is requesting this amount for disposition as it reflects the actual foregone revenue balance. PUC collected $180,147 of the $192,359 and is requesting to collect the difference of $12,211 including carrying charges of $2,536 from customers.

Table 9-10: Account 1509 COVID-19 Forgone Revenue – IRM Delayed Implementation

Acct 1509	Forecasted Foregone	Actual Foregone	Actual Collected	Forecast Jul - Oct 2022	Total Rider Collected	Variance
RESIDENTIAL SERVICE CLASSIFICATION	$ 155,117	$ 135,019	$ (69,604)	$ (52,956)	$ (122,559)	$ 12,460
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	$ 22,253	$ 21,994	$ (14,190)	$ (11,771)	$ (25,961)	$ (3,967)
GENERAL SERVICE 50 to 4,999 kW SERVICE CLASSIFICATION	$ 32,876	$ 33,296	$ (17,322)	$ (13,259)	$ (30,581)	$ 2,715
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	$ 269	$ 301	$ (85)	$ (66)	$ (151)	$ 150
SENTINEL LIGHTING SERVICE CLASSIFICATION	$ 274	$ 281	$ (279)	$ (217)	$ (496)	$ (215)
STREET LIGHTING SERVICE CLASSIFICATION	$ 1,433	$ 1,468	$ (223)	$ (176)	$ (399)	$ 1,069
Balance	**$ 212,221**	**$ 192,359**	**$ (101,703)**	**$ (78,445)**	**$ (180,147)**	**$ 12,211**
Carrying Costs		$ 4,291			$ (1,756)	$ 2,536
Balance		**196,650**			**(181,903)**	**$ 14,747**

9.5.2.6 Account 1509: COVID-19 Incremental Expense Variance

In its March 25, 2020 letter[3], the OEB acknowledged that electricity distributors may incur incremental costs as a result of the ongoing COVID-19 emergency. The Accounting Order established a new COVID Deferral/Variance Account ("COVID DVA"), together with three sub-accounts, for electricity distributors to use to track incremental costs and lost revenues related to the COVID-19 emergency.

On May 14, 2020, the OEB issued a letter initiating the Consultation on the Deferral Account – Impacts Arising from the COVID-19 Emergency (the "Consultation") under OEB File Number: EB-2020-0133. As outlined in this letter, the objective of the Consultation is to assist the OEB in the development of new accounting guidance related to the COVID DVA and filing requirements, where appropriate, for the review and disposition of the account, giving due regard to bill impacts on customers.

As at December 31, 2020, the Consultation process remained ongoing, however PUC Management carefully considered the appropriateness of the amounts recorded in its COVID DVA and recorded 100% of COVID costs based on the guidance available at the time.

On June 17, 2021, the OEB issued a Report of the Board[4] in the OEB's consultation on COVID-19 Deferral Account application. The OEB stated that its Report should be viewed as a set of guidelines – a roadmap to aid utilities in understanding the OEB's expectation with respect to their potential requests for relief associated with this Account. Based on the Report, PUC did a full review of the amounts recorded in Account 1509 and recorded an adjustment for ineligible

[3] OEB Letter, March 25, 2020, Accounting Order for the Establishment of Deferral Accounts to Record Impacts Arising from the COVID-19 Emergency
[4] OEB Report, June 17, 2021, Regulatory Treatment of Impacts Arising from the COVID-19 Emergency

amounts in 2021. PUC requests to dispose of the eligible balance of $401,767, including carrying costs for incremental expenses related to COVID-19.

The OEB Report lays out the rules and operations of the Account, and PUC assessed its account balance as follows:

- The OEB determined that recovery of any balances recorded in the Account should be subject to evidence that the costs are not only reasonable, but also that recovery of the costs is necessary for the utility to maintain its opportunity to earn a fair return over the long run.
- The OEB defined two pools of amounts to be recorded in the COVID-19 deferral account.
  - Exceptional pool sub-account; and
  - The remaining sub-accounts.
- Incremental bad debt arising from voluntary cessations of disconnections implemented by utilities may be included in the exception pool sub-account. PUC was unable to determine if there was any incremental bad debt associated with cessations of disconnections.
- The OEB adopted a three-part means test for recovery as follows:
  - First Means Test - If a distributor's regulated ROE is greater than 12%, no amounts are eligible for inclusion in the account.
    - PUC's regulated ROE in 2020, with no inclusion of balances in account 1509, was estimated at 5.78%, on an after-tax basis, therefore PUC meets the first means test.

- Second Means Test - If a distributor's regulated ROE is less than 12%, they are eligible to recover the portion of the costs recorded in the exceptional pool sub- account, up to the point that their Regulated ROE becomes 12%. There will be no recovery of exceptional pool sub-account distributors Regulated ROE above 12%.
    - By recovering the 2020 balance of the exceptional pool sub- account in account 1509 PUC's regulated ROE becomes 6.27%, on an after-tax basis. PUC meets the second means test and is eligible for full recovery of its exceptional pool sub-accounts.

- Third Means Test - After recording amounts to the exceptional pool sub-account, if a distributor's regulated ROE is greater than 6.00%, no remaining sub-account amounts are eligible for inclusion in the account.
    - Since PUC's regulated ROE, after recording the exceptional pool sub-account in Account 1509, is 6.27%, PUC does not meet this means test as its regulated ROE is greater than 6.00%, PUC is not eligible to recover any remaining sub-account amounts.
- PUC has only filed for recovery of mandated government or OEB-initiated programs. It is not eligible nor is it requesting further cost recovery relating to remaining sub-account amounts. As provided in Table 9-11 below, costs that PUC is requesting for disposal relate to:
    - Incremental billing expenses;
    - Incremental labour expenses directly from government and OEB initiated programs (i.e., CEAP program, GA Deferral, Emergency TOU, COVID DVA);

- Lost revenues from certain reduced/waived specific service charges, specifically, costs are related to late payment charges waived in 2020; and
- Additional leap funding to assist customers.

o As the majority of amounts were incurred in 2020, the materiality threshold is based on the last OEB approved Materiality Threshold (i.e., OEB approved Distribution Service Revenue of $21,888,965 X 0.5% = $109,445). Materiality threshold for this account was therefore met.

o Amounts approved for disposition were allocated based on number of customers, as provided in the OEB DVA model.

Table 9-11: COVID ROE Comparison Calculations

Regulated net income		ROE Original		ROE COVID Exceptional	ROE Remove COVID
Regulated net income (loss), as per RRR 2.1.7		$2,757,662.04	a	$1,742,524.36	$1,542,597.04
Adjustment items:					
Non-rate regulated items and other adjustments (Appendix 1)		$2,052.20	b	$2,052.20	$2,052.20
Unrealized (gains)/losses on interest rate swaps (Not applicable if recorded in Other Comprehensive Income)			c		
Actuarial (gains)/losses on OPEB and/or Pensions not approved by the OEB			d		
Non-recoverable donations (Appendix 2)		$0.00	e	$0.00	$0.00
Net interest/carrying charges from DVAs (Appendix 3)		$80,137.64	f	$80,137.64	$80,137.64
Interest adjustment for deemed debt (Appendix 4)		$651,690.04	g	$651,690.04	$651,690.04
Adjusted regulated net income before tax adjustments		$3,491,541.92	h=a+b+c+d+e+f+g	$2,476,404.24	$2,276,476.92
Add back:					
Future/deferred taxes expense		$284,105.00	i	$284,105.00	$284,105.00
Current income tax expense (Does not include future income tax)		$76,523.00	j	$76,523.00	$76,523.00
Deduct:					
Current income tax expense for regulated ROE purposes (Appendix 6)		$271,001.17	k	$271,001.17	$271,001.17
Adjusted regulated net income		$3,581,168.75	l=h+i+j-k	$2,566,031.07	$2,366,103.75
Deemed Equity					
Rate base:					
Cost of power		$84,258,656.80	m	$84,258,656.80	$84,258,656.80
Operating expenses before any applicable adjustments		$11,471,101.60	n1	$12,278,571.49	$12,478,498.81
Other Adjustments:					
			n2		
Adjusted operating expenses		$11,471,101.60	n=n1-n2	$12,278,571.49	$12,478,498.81
Total Cost of Power and Operating Expenses		$95,729,758.40	o=m+n	$96,537,228.29	$96,737,155.61
Working capital allowance % as approved in the distributor's last CoS Decision and Order		7.50%	% p	7.50%	7.50%
Total working capital allowance ($)		$7,179,731.88	q=o*p	$7,240,292.12	$7,255,286.67
PP&E					
Opening balance - regulated PP&E (NBV) (Appendix 5)		$94,529,217.41	r	$94,529,217.41	$94,529,217.41
Adjusted closing balance - regulated PP&E (NBV) (Appendix 5)		$95,727,547.84	s	$95,727,547.84	$95,727,547.84
Average regulated PP&E		$95,128,382.63	t=(r+s)/2	$95,128,382.63	$95,128,382.63
Total rate base		$102,308,114.51	u=q+t	$102,368,674.75	$102,383,669.30
Regulated deemed short-term debt % and $	4.00%	$4,092,324.58	v1=v*u	$4,094,746.99	$4,095,346.77
Regulated deemed long-term debt % and $	56.00%	$57,292,544.12	w1=w*u	$57,326,457.86	$57,334,854.81
Regulated deemed equity % and $	40.00%	$40,923,245.80	x1=x*u	$40,947,469.90	$40,953,467.72
Regulated Rate of Return on Deemed Equity (ROE)					
Achieved ROE%		8.75%	% y= l / x1	6.27%	5.78%
Deemed ROE% from the distributor's last CoS Decision and Order		9.00%	% z	9.00%	9.00%
Difference - maximum deadband 3%		-0.25%	% z1 = y-z	-2.73%	-3.22%
ROE status for the year (Over-earning/Under-earning/Within 300 basis points deadband)		Within 300 basis points deadband	z2	Within 300 basis points deadband	Under-earning

Table 9-12: Account 1509 COVID-19 Incremental Expense Detail

Acct 1509	Balance
Incremental billing expenses	$ 577
Incremental labour	$ 250,166
Waived Interest	$ 119,153
Additional LEAP funding	$ 13,133
Principal	**$ 383,029**
Carrying Costs	$ 18,738
Balance	**$ 401,767**

PUC Services Inc. ("PUCS") provides management and operation services for PUC. During the COVID pandemic, additional time was dedicated to supporting the COVID pandemic impact on PUC to ensure its services remained reliable, and its customers and employees were safe. The incremental costs were above the regular management and operation services provided by PUCS as they were to deal with additional services dealing with the extraordinary government and OEB emergency programs.

PUC followed the application rules and operations of the account for recoverability provided by the Report of the OEB. The account was established to recognize the exceptional nature of the pandemic. Since PUC is a virtual utility, additional resources were required to be provided by PUCS above and beyond operation expectations. These resulted in higher expenses for PUC of which costs were prudent to PUC's financial viability to ensure that employee and customers were provided with services, and they were kept safe. The extraordinary costs were in relation to all of the exceptional pool eligible amounts. It was necessary for PUC to obtain additional resources from PUCS to manage these programs to support customers. PUC should not be required to bear the financial impact of these actions.

PUC believes it acted prudently to minimize the impacts and fully exploited all available cost-reductions and savings. PUCS implemented a well-executed disaster recovery plan, appropriate planning processes, and pivots in business plans as appropriate to be able to carry out and provide services to PUC during the pandemic. The incremental costs included in the DVA are for additional PUCS labour to execute these programs, waived interest to reduce impact to customers with late payments, some billing changes and additional LEAP to customers.

No amounts have been forecasted in 2022 or 2023. PUC proposes to discontinue the use of this Account.

9.5.2.7 Account 1568: LRAM Variance Account

This account includes the lost revenue adjustment mechanism ("LRAM") variances in relation to the conservation and demand management ("CDM") programs or activities undertaken by PUC in accordance with Board prescribed requirements. PUC requested that its consultant, Indeco update the LRAMVA model for the purposes of this Application.

The details of this claim are outlined in Exhibit 4 along with Indeco's report and the LRAMVA Work form. PUC had a remaining amount from 2018 COS that is being proposed in the amount of $8,578 refunded to customers. The additional claim from 2023 COS is $205,155 collected from customers. Therefore, PUC requests disposition of Account 1568 for the amount of $196,577 to be collected from customers, including interest to April 30, 2023. PUC is requesting disposition of the balance over a one-year period.

Table 9-12: Account 1568 LRAM (2018 COS)

Acct 1568	2017	2018	2019	2020	2021	Forecast 2022 -Apr 2023
Opening	$ (13,391)	$ (109,860)	$ 419,118	$ 288,959	$ 35,062	$ (6,064)
1568 Disposition		$ 528,978				
1568 Recovery	$ (96,469)		$ (130,159)	$ (253,897)	$ (41,126)	$ (22,841)
Closing	$ (109,860)	$ 419,118	$ 288,959	$ 35,062	$ (6,064)	$ (28,904)
Carrying costs					$ 20,326	$ 20,326
Balance					**$ 14,262**	**$ (8,578)**

Table 9-14: Account 1568 LRAM (2023 COS)

Acct 1568	2018	2019	2020	2021	2022	Forecast Jan-Apr 2023
1568 Disposition	47,519	45,919	34,779	35,197	31,105	**194,519**
Carrying costs					6,941	**10,636**
Balance	**47,519**	**45,919**	**34,779**	**35,197**	**38,047**	**205,155**
LRAM - (2018 COS)						**(8,578)**
LRAM - (2023 COS)						**$ 205,155**
						196,577

PUC requests to continue this account in the event that PUC will be able to participate in incremental CDM programs that would be eligible to use this mechanism in the future.

9.2.5.8 Account 1592: PILs and Tax Variance – CCA Changes

On July 25, 2019, the OEB released a letter titled Accounting Direction Regarding Bill C-97 and Other Changes in Regulatory or Legislated Tax Rules for Capital Cost Allowance. This letter discusses the government's Accelerated Investment Incentive ("AII") which provides for a first-year increase in capital cost allowance (CCA) deductions on eligible capital assets acquired after November 20, 2018.

PUC has been calculating the amount annually which has been recorded as part of its year end transactions. The calculation uses PUC's 2018 actual capital additions as the basis of the CCA entry for each year from 2018-2022 – this differs from using the actual additions in each given year. As a result, the difference between the yearly actual additions and the 2018 actual additions have been captured in its loss carry forwards. This is explained in further detail in Exhibit 6 Section 2.6.2. To the end of December 31, 2021, PUC has recorded $410,974, including carrying charges. PUC has also forecasted the principal activity in 2022 of $189,219 in 2022. The account does not include amounts related to the Sub 16 or SSG ICMs as these amounts have also been captured in the loss carry forwards.

As proposed in Table 9-15 below, PUC requests disposal of $613,546 in principal and carrying charges to the end of December 31, 2022. PUC is requesting to dispose of the forecasted balance to the end of 2022. The difference between actual capital additions and budgeted capital additions, used as the basis for 2022 CCA amounts, will be immaterial and PUC is not requesting to continue to use account 1592 for the accumulated CCA tax variance going forward as it all has been reflected in its 2023 PILs tax calculation through a CCA smoothing adjustment.

PUC would continue to use account 1592, as necessary, in the event that either the Federal or Provincial governments make changes to corporate income tax rates or parameters underpinning PUC's 2023 PILs component of Distribution Revenue.

Table 9-15: Account 1592 PILs – CCA

Acct 1592	2018	2019	2020	2021	Forecast 2022	Total
Opening						
Activity	$ -	$ (147,969)	$ (136,136)	$ (125,250)	$ (189,219)	**$ (598,574)**
Carrying costs						**$ (14,973)**
Balance						**$ (613,546)**

Acct 1592	2018	2019	2020	2021	Forecast 2022	Total
Prior CCA	$ 205,202	$ 599,196	$ 961,684	$ 1,295,186	$ 1,396,818	**$ 4,252,884**
Accelerated CCA	$ 205,202	$ 1,009,600	$ 1,339,269	$ 1,642,577	$ 1,921,632	**$ 5,913,078**
Difference in CCA	$ -	$ 410,404	$ 377,585	$ 347,391	$ 524,814	$ 1,660,194
Tax Impact @ 26.5%	**$ -**	**$ 108,757**	**$ 100,060**	**$ 92,059**	**$ 139,076**	**$ 439,951**
Grossed-up	**$ -**	**$ 147,969**	**$ 136,136**	**$ 125,250**	**$ 189,219**	**$ 598,573**

9.6. GROUP 2 ACCOUNTS – TO COMMENCE/CONTINUE/DISCONTINUE

Table 9-15 below lists all Group 2 accounts which PUC will continue/discontinue/commence on a going-forward basis.

Table 9-15 – Group 2 Accounts – Commence/Continue/Discontinue

Group 2 and Other Accounts	Account Number	Commence Continue Discontinue	Explanation
Other Regulatory Assets - Sub Account - Incremental VVO Savings or Costs	1508	Commence	To record on-going SSG VVO impacts.
Other Regulatory Assets - Sub Account - EPC Contract Liquidated Damages	1508	Commence	To record liquidated damages due to performance or delay in EPC contract.
Other Regulatory Assets - Sub-Account - Pole Attachment	1508	Continue	On-going in event of a decrease in expected Pole Rental charge.
PILs and Tax Variance	1592	Continue	Remain available to use for other legislative tax changes not reflected in rates.
LRAM Variance Account	1568	Continue	On-going in event of future CDM programs.
Other Regulatory Assets - Sub-Account - ICM Sub-station 16	1508	Discontinue	Rate Rider in effect until April 30, 2023
Other Regulatory Assets - Sub-Account - Sault Smart Grid	1508	Discontinue	Rate Rider in effect until April 30, 2023
COVID-19 Deferral Account	1509	Discontinue	Final disposition at rebasing; no activity expected
Retail Cost Variance Account - Retail	1518	Discontinue	Final disposition at rebasing; forecast activity to April 30, 2023
Retail Cost Variance Account - STR	1548	Discontinue	Final disposition at rebasing; forecast activity to April 30, 2023

9.7. ESTABLISHMENT OF NEW DEFERRAL VARIANCE ACCOUNTS

PUC is requesting two new DVA accounts, via the accounting orders attached as Appendix B and Appendix C, to assist with the financial transactions related to its SSG Project (EB-2018-0219/EB-2020-0249). PUC is requesting the first DVA account to satisfy the following condition of the SSG ICM approval.

> *"PUC Distribution shall file all available information on the proposed Project performance metrics that it intends to track, along with proposed targets, in its next rebasing application. This shall include an appropriate metric and targets to symmetrically link the VVO performance of the Project to PUC's allowable ROE for this Project."*

This DVA account will symmetrically link VVO savings to ROE as presented in the draft accounting order attached as Appendix B to Exhibit 2.

PUC is requesting the second DVA account to satisfy the following condition of the SSG ICM approval.

> *"Any EPC Contract liquidated damages resulting from "performance" or "delay" shall be used to reduce the Project capital cost and would be settled at the time of the next rebasing."*

This second DVA account is to link any possible liquidated damages received as a result of the overall project completion with PUC and its third-party contractor. A draft accounting order for this second DVA account is attached as Appendix C.

9.8. DISPOSITION OF DEFERRAL AND VARIANCE ACCOUNTS

For the calculation of proposed rate riders, PUC has utilized the billing determinants arising from the 2023 Load Forecast inclusive of CDM Adjustments, as presented in Table 9-16 below. For more details regarding the 2023 Load Forecast and billing determinants please see Exhibit 3.

Table 9-16: Total Billing Determinants

Rate Class	Customer Numbers	kWh	kW
Residential	30,340	274,738,681	-
General Service < 50 kW	3,400	79,051,528	-
General Service 50 to 4,999 kW	344	221,450,388	547,687
Sentinel Lighting	25	878,528	
Street Lighting	317	193,841	566
Unmetered Scattered Load	8,037	2,459,994	7,200
Total	42,463	578,772,960	555,453

9.9. PROPOSED RATE RIDERS

Consistent with the Model provided by the Board, PUC has calculated the following rate riders to reflect disposition over 12 months:

- Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj. and Account 1580 WMS CBR Class B)
- Rate Rider Calculation for Account 1580 WMS CBR Class B
- Rate Rider Calculation for RSVA - Power - Global Adjustment
- Rate Rider Calculation for Group 2 Accounts
- Rate Rider Calculation for Account 1568 - LRAMVA
- Rate Rider Calculation for Account 1509 – COVID Incremental Expense

Table 9-17: Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj. and Account 1580 WMS CBR Class B)

Rate Class	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL SERVICE CLASSIFICATION	kWh	274,738,681	$ 212,267	0.0008
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ 64,107	0.0008
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	547,687	$ 183,597	0.3352
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ 695	0.0008
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ 2,027	0.2815
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ 191	0.3374
Total			**$ 462,884**	

Table 9-18: Rate Rider Calculation for Account 1580 WMS, sub-account CBR Class B

Rate Class	Units	kW / kWh / # of Customers	Allocated Sub-account 1580 CBR Class B Balance	Rate Rider for Sub-account 1580 CBR Class B
RESIDENTIAL SERVICE CLASSIFICATION	kWh	274,738,681	$ (38,506)	(0.0001)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ (11,079)	(0.0001)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	458,921	$ (25,738)	(0.0561)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ (123)	(0.0001)
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ (345)	(0.0479)
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ (27)	(0.0480)
Total			**$ (75,818)**	

Table 9-19: Rate Rider Calculation for RSVA - Power - Global Adjustment

Rate Class	Units	kW / kWh / # of Customers	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL SERVICE CLASSIFICATION	kWh	3,364,092	$ (6,924)	(0.0021)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	12,067,162	$ (24,838)	(0.0021)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kWh	151,116,068	$ (311,046)	(0.0021)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	-	$ -	-
STREET LIGHTING SERVICE CLASSIFICATION	kWh	2,330,282	$ (4,796)	(0.0021)
SENTINEL LIGHTING SERVICE CLASSIFICATION	kWh	-	$ -	-
Total			**$ (347,605)**	

Table 9-20: Rate Rider Calculation for Group 2 Deferral / Variance Accounts Balances

Rate Class	Units	kW / kWh / # of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	30,340	$ (267,765)	(0.7355)
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ (82,192)	(0.0010)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	547,687	$ (234,762)	(0.4286)
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ (937)	(0.0011)
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ 5,971	0.8293
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ 99	0.1754
Total			**$ (579,586)**	

Table 9-21 - Rate Rider Calculation for Account 1568 LRAMVA

Rate Class	Units	kW / kWh / # of Customers	Allocated Account 1568 Balance	Rate Rider for Account 1568
RESIDENTIAL SERVICE CLASSIFICATION	kW	274,738,681	$ 44,507	0.0002
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	kWh	79,051,528	$ (111,834)	(0.0014)
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	kW	547,687	$ 263,903	0.4819
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	kWh	878,528	$ -	-
STREET LIGHTING SERVICE CLASSIFICATION	kW	7,200	$ -	-
SENTINEL LIGHTING SERVICE CLASSIFICATION	kW	566	$ -	-
Total			**$ 196,576**	

Table 9-22 - Rate Rider Calculation for Account 1509 COVID-19 Incremental Expense

Rate Class	Units	kW / kWh / # of Customers	Allocated Account 1509 Balance	Rate Rider for Account 1509
RESIDENTIAL SERVICE CLASSIFICATION	# of Customers	30,340	$ 246,574	0.6773
GENERAL SERVICE LESS THAN 50 KW SERVICE CLASSIFICATION	# of Customers	3,400	$ 60,775	1.4896
GENERAL SERVICE 50 TO 999 KW SERVICE CLASSIFICATION	# of Customers	344	$ 88,669	21.4799
UNMETERED SCATTERED LOAD SERVICE CLASSIFICATION	# of Customers	25	$ 811	2.7021
STREET LIGHTING SERVICE CLASSIFICATION	# of Customers	8,037	$ 4,239	0.0440
SENTINEL LIGHTING SERVICE CLASSIFICATION	# of Customers	317	$ 698	0.1835
Total			**$ 401,766**	

APPENDIX A

Accounting Order –
Sault Smart Grid_ ICM

PUC Distribution Inc.

2022 ICM Application – The Sault Smart Grid project

EB-2020-0249

Accounting Order

Account 1508 Other Regulatory Assets

Sub-accounts Contributed Capital

February 26, 2020

PUC Distribution Inc. - 2022 ICM Application – The Sault Smart Grid project

Accounting Order – Account 1508 Other Regulatory Assets

PUC shall establish ten (10) variance accounts for the fulfillment of the ICM accounting treatment for the Sault Smart Grid Application with rates effective May 1, 2022. The following is a list of the 10 accounts with their descriptions. There are four additional accounts being requested for the treatment of capital contributions received from NRCan.

1) Account 1508 Other Regulatory Assets, Sub-account Incremental Capital Expenditures
This account shall be used to record actual ICM capital amounts, subject to the assets being used or useful (i.e. in service)

2) Account 1508 Other Regulatory Assets, Sub-account ICM Carrying Charges
Carrying charges calculated based on the actual revenue requirement associated with the approved ICM shall be recorded in this sub account. Carrying charges shall be calculated using simple interest applied to the opening balances in the account and shall be recorded monthly in a sperate carrying charges sub-account f this account. The interest rate shall be the rate prescribed by the Board.

3) Account 1508 Other Regulatory Assets, Sub-account ICM Depreciation Expense
This account shall be used to record the depreciation expense associated with the eligible capital amounts recorded in Account 1508 Other Regulatory Assets, Sub-account Incremental Capital Expenditures.

4) Account 1508 Other Regulatory Assets, Sub-account Accumulated Depreciation
This account shall be credited with the amounts charged to Account 1508 Other Regulatory Assets, Sub-account Depreciation Expense.

5) Account 1508 Other Regulatory Assets, Sub-account ICM Rate Rider Revenue
Amounts recorded in this account shall include the actual rate rider revenues collected in relation to the Board-approved rate riders determined for the ICM project.

6) Account 1508 Oth9er Regulatory Assets, Sub-account ICM Rate Rider Carrying Charges

This account shall be used to record the carrying charges that apply to Account 1508 Other Regulatory Assets, Sub-account ICM Rate Rider Revenues. Carrying charges shall be calculated using simple interest applied to the opening balances in the account and shall be recorded monthly in a sperate carrying charges sub-account f this account. The interest rate shall be the rate prescribed by the Board.

7) Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue – Contributed Capital

This account shall be used to record the amount received in contributed capital from NRCan funding for the ICM capital project.

8) Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue Carrying Charges

This account shall be used to record the carrying charges on Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue – Contributed Capital. Carrying charges shall be calculated using simple interest applied to the opening balances in the account and shall be recorded monthly in a sperate carrying charges sub-account f this account. The interest rate shall be the rate prescribed by the Board.

9) Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue Amortization

This account shall be used to record revenue associated with the amortization of the Deferred Revenue received for the NRCan grant.

10) Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue Accumulated Amortization

This account shall be credited with the amounts charged to Account 1508 Other Regulatory Assets, Sub-account Deferred Revenue Amortization.

A sample of the accounting entries has been provided in Appendix 1 below.

Appendix 1: ICM Accounting Entries

	OEB #	Sub #	DESCRIPTION	Debit	Credit
2022	1508	1	Other Regulatory Assets - Sub-account Incremental Capital Expenditures	-	
	2055		Construction Work in Progress		-
	1508	2	Other Regulatory - Sub-account ICM Capital Expenditures Carrying Charges	-	
	1525		Misc Deferred Debits/Credits		-
	1508	3	Other Regulatory - Sub-account "ICM Depreciation Expense"	-	
	1508	4	Other Regulatory - Sub-account "Accumulated Depreciation"		-
	1100		Cash/Accounts Recievable	-	
	1508	5	Other Regulatory - Sub-account "ICM Rate Riders		-
	1525		Misc Deferred Debits/Credits	-	
	1508	6	Other Regulatory - sub-account "ICM Rate Rider Carrying Charges"		-
	1110		A/R	-	
	1508	7	Other Regulatory – Sub-account "Deferred Revenue – Contributed Capital"		-
	1525		Misc Deferred Debits/Credits	-	
	1508	8	Other Regulatory - Sub-account "Deferred Revenue -Carrying Charges"		-
	1508	10	Other Regulatory – Sub-account "Deferred Revenue – Accumulated Amortization"	-	
	1508	9	Other Regulatory - Sub-account "Deferred Revenue Amortization"		-

	OEB #	Sub #	DESCRIPTION	Debit	Credit
2023	1600-1999		1606-1990 PP&E Accounts1	-	
	1508	1	Other Regulatory Assets - Sub-account Incremental Capital Expenditures		-
	5705		Depreciation Expense	-	
	1508	3	Other Regulatory - Sub-account "ICM Depreciation Expense"		-
	1508	4	Other Regulatory - Sub-account "Accumulated Depreciation"	-	
	2105		Accumulated Depreciation		-
	1508	5	Other Regulatory - Sub-account "ICM Rate Riders	-	
	4080		Distribution Revenue		-
	1508	8	Other Regulatory - Sub-account "Deferred Revenue -Carrying Charges"	-	
	1508	6	Other Regulatory - sub-account "ICM Rate Rider Carrying Charges"	-	
	1525		Misc Deferred Debits/Credits	-	
	1508	2	Other Regulatory - Sub-account ICM Capital Expenditures Carrying Charges		-
	1508	9	Other Regulatory - Sub-account "Deferred Revenue Amortization"	-	
	4245		Government and Other Assistance Directly Credited to Income		-
	2105		Accumulated Depreciation	-	
	1508	10	Other Regulatory – Sub-account "Deferred Revenue – Accumulated Amortization"		-

APPENDIX B

Accounting Order - Sault Smart Grid_Voltage/VAR Optimization Linkage to Return on Equity

PUC Distribution Inc.

2023 Cost of Service Application – Sault Smart Grid Project Voltage / VAR Optimization Linkage to Return on Equity

EB-2022-0059

Accounting Order

Account 1508 Other Regulatory Assets

Sub-accounts Incremental VVO Savings or Costs

August 31, 2022

PUC Distribution Inc. - 2023 Cost of Service Application – Sault Smart Grid Project VVO Linkage to ROE

Accounting Order – Account 1508 Other Regulatory Assets

As part of the Ontario Energy Board's ("OEB") decision on the Sault Smart Grid project (EB-2018-0219/EB-2020-0249) ("SSG"), PUC Distribution Inc. ("PUC") was required to file all available information on the proposed SSG performance metrics that it intends to track, along with proposed targets, in its next rebasing application. The OEB required PUC to include an appropriate metric and targets to symmetrically link the Voltage / VAR Optimization ("VVO") performance of SSG to PUC's allowable Return on Equity ("ROE") for this Project. PUC is proposing to do this through the use of a 1508 – Other Regulatory Assets Sub Account where it shares in 50% of the costs and savings to customers. The following describes the calculation that links VVO % savings to ROE and the corresponding sample journal entries for the sharing of incremental savings or costs to customers.

VVO Link to ROE

The following steps, as outlined in Table 1, details the methodology PUC will use to calculate the revised net benefit to customers based on actual annual consumption savings and actual year COP.

Table 1 Scenarios Calculating Customer Net Benefit[1]

	Top of Dead Band	Bottom of Dead Band	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Measured (estimate) VVO Consumption Savings	16,324,838	14,327,652	13,350,394	16,822,310	782,551	29,750,110
PUC Annual Consumption	604,623,538	606,565,655	607,598,147	603,161,981	603,161,981	603,161,981
PUC Consumption without SSG (projection from LF)	620,948,376	620,893,307	620,948,541	619,984,291	603,944,531	632,912,091
% Savings	2.70%	2.36%	2.20%	2.79%	0.13%	4.93%
PUC Cost of Power Paid	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488	$ 69,302,488
Avg $/kWh	0.1146	0.1143	0.1141	0.1149	0.1149	0.1149
PUC Cost of Power Paid without SSG consumption savings	$ 71,173,655	$ 70,939,478	$ 70,825,230	$ 71,235,348	$ 69,392,402	$ 72,720,735
Customer Energy Savings ($)	$ 1,871,167	$ 1,636,990	$ 1,522,742	$ 1,932,860	$ 89,914	$ 3,418,247
Dollar Savings from Loss Factor consumption reduction (Appendi	$ 79,664	$ 79,664	$ 79,664	$ 79,664	$ 79,664	$ 79,664
Total purchased power savings	**$ 1,950,831**	**$ 1,716,654**	**$ 1,602,406**	**$ 2,012,524**	**$ 169,578**	**$ 3,497,911**
Additional revenue from increased SSG asset base	$ 1,755,460	$ 1,755,460	$ 1,755,460	$ 1,755,460	$ 1,755,460	$ 1,755,460
Benefit of reduced capital expenditures witth SSG	($304,390)	($304,390)	($304,389)	($304,388)	($304,388)	($304,388)
Additional O & M expenses due to SSG implementation	$ 296,400	$ 296,400	$ 296,400	$ 296,400	$ 296,400	$ 296,400
Operating efficiency benefits due to SSG implementation	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)	($30,816)
Change In Revenue Requirement	$ 1,716,654	$ 1,716,654	$ 1,716,655	$ 1,716,656	$ 1,716,656	$ 1,716,656
Annual net benefit to customers	$ 234,177	-$ 0	-$ 114,249	$ 295,868	-$ 1,547,078	$ 1,781,255

1 – These numbers are for illustration purposes only. The actual amount will vary given the VVO kWh savings from year to year.

First, PUC will measure VVO consumption (kWh) savings on an annual basis. The methodology for calculating VVO savings is being developed by in collaboration with PUC's SSG contractor which will be used as an input. The very top line of Table 1 shows assumption of what that input might be for the purposes of this calculation and the VVO linkage to ROE. These consumption savings are added back to PUC's actual total consumption in each year to determine the resulting VVO savings as a percentage. This is shown in the top four rows of Table 1 above.

Next, the actual cost of power paid each year is divided by the actual consumption to obtain and average cost per kWh. This average cost per kWh is multiplied by PUC's consumption without VVO savings to get the COP customer would have paid in absence of the VVO savings. The methodology then must be adjusted for PUC's loss factor. As such, the calculation compares the approved loss factor to PUC's actual loss factor. As outlined in PUC's SSG Project ICM Application (EB-2018-0219/2020-0249) in Appendix AA14, it was noted that a reduction in loss factor would occur as a result of the SSG project. PUC will use Appendix AA14 yearly to input the additional dollar savings from loss factor.

The final step is to review the revenue requirement calculation for SSG included in rates. The benefit of reduced future capital expenditures, as described in EB-208-0219/2020-0249 is $234,177 in each year moving forward. Additional O&M expenses of $296,400 and operating efficiency savings of $30,816 are also factored in, resulting in a total cost to customers (through rates). The calculated energy savings from VVO in the first step is compared to the calculated costs through revenue requirement of the SSG Project. The difference is the net benefit/(disadvantage) to customers.

Considering that the COP will fluctuate on a yearly basis, PUC proposes a band where the breakeven point, (i.e., $0 savings to customers) as a percentage is the low end of the band, with the upper limit being 2.70% or $234,177 VVO savings.

This methodology is illustrated in Table 1, with the second column showing the VVO savings target of 2.70%, the high end of the dead band, and the third column showing the lower end of dead band (i.e., customer breakeven) at 2.36% VVO savings. This ensures customers will receive a no net bill increase.
Only when the VVO consumption savings in a year are outside of the established dead band (2.36% to 2.70%), is a DVA entry triggered. Below the dead band, incremental costs to rate payers are shared 50/50 between ratepayers and PUC. Above the dead band, incremental savings to ratepayers are shared 50/50

between ratepayers and PUC. Scenario 1 shows a VVO savings of 2.20%, which results in incremental costs to customer of $114,249. PUC proposes to share 50/50 in those costs, causing a credit of $57,124 to the new DVA account. Scenario 2 shows a VVO savings of 2.79%, which results in incremental savings to customers of $295,868. The dollar value of VVO savings at the top end of the dead band ($234,177) is subtracted from this, resulting in $61,692 that is shared 50/50 with ratepayers and PUC. This creates a debit entry to the new DVA account for $30,846. Table 2 below shows the accounting entries for the DVA account for scenarios 1-4 in Table 1 above.

Table 2 – Accounting Entries for Scenarios 1-4[1]

Journal Entry				
	Scenario 1	**Scenario 2**	**Scenario 3**	**Scenario 4**
4080 Distribution Revenue	$57,124		$773,539	
1508 Other Regulatory Assets, Sub-account Incremental SSG Costs	$57,124		$773,539	
to record the reduction in savings to PUC customers.				
1508 Other Regulatory Assets, Sub-account Incremental SSG Costs		$30,846		$773,539
4080 Distribution Revenue		$30,846		$773,539
to record the reduction in savings to PUC customers.				

1 – These numbers are for illustration purposes only. The actual amount will vary given the VVO kWh savings from year to year.

1) Account 1508 Other Regulatory Assets, Sub-account Incremental SSG Costs

This account shall be used to record incremental SSG costs to customers when the VVO percentage savings multiplied by the cost of power results in an amount that is less than zero dollars savings to customers. The costs that are below zero dollars will be shared 50/50 between ratepayers and PUC.

2) Account 1508 Other Regulatory Assets, Sub-account Incremental VVO Savings

This account shall be used to record incremental VVO savings to customers when the dollar savings is more than two times the VVO dollar savings at 2.70%. The savings that are above this threshold will be shared 50/50 between ratepayers and PUC.

3) Account 1508 Other Regulatory Assets, Sub-account Incremental VVO Costs or Savings Carrying Charges

Carrying charges calculated on the year end balance shall be recorded in this sub account. Carrying charges shall be calculated using simple interest applied to the opening balances in the account and shall be recorded monthly in a separate carrying charges sub account. The interest rate shall be the rate prescribed by the Board.

A sample of the accounting entries has been provided in Appendix 1 below.

Appendix 1: 1508 Other Regulatory Assets – Incremental VVO Costs or Savings Journal Entries

1508 Other Regulatory Assets – Incremental VVO Costs or Savings	$XX	
4080 Distribution Revenue		$XX
To record the incremental savings to customers		

4080 Distribution Revenue	$XX	
1508 Other Regulatory Assets – Incremental VVO Costs or Savings		$XX
To record the incremental costs to customers		

APPENDIX C

Accounting Order – Sault Smart Grid_EPC Contract Liquidated Damages

PUC Distribution Inc.

2023 Cost of Service Application – Sault Smart Grid Project Liquidated Damages

EB-2022-0059

Accounting Order

Account 1508 Other Regulatory Assets

Sub-accounts SSG EPC Contract Liquidated Damages

August 31, 2022

PUC Distribution Inc. - 2023 Cost of Service Application – Sault Smart Grid Project Liquidated Damages

Accounting Order – Account 1508 Other Regulatory Assets

As part of the Ontario Energy Board's ("OEB") decision on the Sault Smart Grid project (EB-2018-0219/EB-2020-0249) ("SSG"), the OEB found that in order to manage the risks associated with SSG and appropriately monitor its progress, the OEB approval was subject to the following condition:

> *"Any EPC Contract liquidated damages resulting from "performance" or "delay" shall be used to reduce the project capital cost and would be settled at the time of the next rebasing."*

No liquidated damages were calculated as of the time of rebasing. This account is intended to ensure the liquidated damages, if any, will be applied so as to reduce project capital costs prior to the next rebasing application. PUC will record the difference in revenue requirement associated with the SSG included in base distribution rates less the revenue requirement associated with the SSG once adjusted to reflect any liquidated damages actually received. The adjustment will occur on the earlier of December 31, 2023 or the date liquidated damages are actually received in accordance with applicable accounting standards. Depending on the timing of settling this liability, the amount may be estimated and further updated once a final amount is received. The following describes the sub account and sample journal entries for the new account.

1) Account 1508 Other Regulatory Assets, Sub-account SSG EPC Contract Liquidated Damages

This account shall be used to record the change in revenue requirement as a result of the decrease in net book value of Sault Smart Grid Assets from liquidated damages received.

2) Account 1508 Other Regulatory Assets, Sub-account SSG EPC Contract Liquidated Damages Carrying Charges

Carrying charges calculated on the year-end balance shall be recorded in this sub account. Carrying charges shall be calculated using simple interest applied to the opening balances in the account and shall be recorded monthly in a separate carrying charges sub account. The interest rate shall be the rate prescribed by the Board. between ratepayers and PUC.

A sample of the accounting entry associated with liquidated damages is presented below.

4080 Distribution Revenue	$XX	
1508 – Other Regulatory Assets – SSG EPC Contract Liquidated Damages		$XX

To record the associated difference in revenue requirement from liquidated damages received.