EXHIBIT 1

ADMINISTRATION

ESSEX POWERLINES CORPORATION

Table of Contents

List of Tables

List of Figures

List of Attachments

Attachment 1-A: EPLC 2024-2025 Business Plan

Attachment 1-B: Executive Certification

Attachment 1-C: OEB 2022 Scorecard

Attachment 1-D: EPLC 2021 Audited Financial Statements

Attachment 1-E: EPLC 2022 Audited Financial Statements

Attachment 1-F: EPLC 2023 Audited Financial Statements

Attachment 1-G: EPLC Annual Report

Attachment 1-H: Customer Engagement Survey

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 Essex Powerlines Corporation 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 January 1, 2025.

Essex Powerlines Corporation
(the "Applicant" or "EPLC").

APPLICATION FOR APPROVAL OF 2025 ELECTRICITY DISTRIBUTION RATES
EB-2024-0022

Filed: April 30, 2024

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1.1 Application

The Applicant, Essex Powerlines Corporation, is referred to in this Application as the "Applicant" or "EPLC." 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 January 1, 2025 (the "Application").

The Applicant is an Ontario Corporation with its offices in the Town of Oldcastle. The Applicant carries on the business of distributing electricity in its service territory which includes four non-contiguous communities: the Towns of Lasalle, Tecumseh and Amherstburg, and the Municipality of Leamington. EPLC's 2025 Cost of Service Application (EB-2024-0022) (the "Application" or "COS" interchangeably) presents evidence demonstrating how EPLC 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 eight years with (i) historical information for the 2018-2023 period, (ii) 2024 Bridge Year; and (iii) a one-year forward test period – the 2025 Test Year. The Distribution System Plan ("DSP") provides an overview of EPLC's asset planning process, objectives and goals, a review of EPLC's asset-related operational performance over a 5-year historical period, and a forecast of planned capital expenditures over the 2025-2029 period. EPLC's last Cost of Service application and DSP was filed on August 28, 2017, for rates effective May 1, 2018.

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

- Exhibit 1 – Administration
- Exhibit 2 – Rate Base and Capital
- Exhibit 3 – Customer and Load Forecast
- Exhibit 4 – Operating Expenses
- Exhibit 5 – Cost of Capital and Capital Structure
- Exhibit 6 – Revenue Requirement and Revenue Deficiency or Sufficiency
- Exhibit 7 – Cost Allocation
- Exhibit 8 – Rate Design
- Exhibit 9 – Deferral and Variance Accounts

EPLC 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 December 15, 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;
- EPLC acknowledges that the OEB may publish an update to its cost of capital parameters for applications for 2025 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
- EPLC 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

1.2.1 Introduction

EPLC 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. EPLC'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. EPLC developed its plans to address and appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives.

Essex Power Corporation is a dynamic energy company that provides safe, reliable, and economical energy supply and services to our customers. Our commitment to innovation, performance management, and leading by example has built the foundation at Essex Power and our affiliates to establish a diverse set of energy products and services that are valued by our customers. At Essex Power, *"Your Power Is Our Priority"*.

1.2.2 About Essex Powerlines Corporation

Essex Power Corporation, incorporated on March 17, 2000, under the *Business Corporations Act* (Ontario), is owned by four municipalities: the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington, and the Town of Tecumseh. Essex Power Corporation is the parent holding company of a regulated local distribution company, Essex Powerlines Corporation, and an unregulated company, Essex Energy Corporation.

Essex Powerlines Corporation is a regulated local distribution company that is a wholly owned subsidiary of Essex Power Corporation. EPLC is responsible for distributing electricity to over 34,000 business and residential customers and connections within the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington, and the Town of Tecumseh.

Essex Energy Corporation is a wholly owned unregulated subsidiary of Essex Power Corporation. Essex Energy Corporation ("EEC") is a dynamic energy technology company providing various services and technology related solutions to electrical utilities, generators, transmitters, and consumers across North America.

Essex Power Corporation's vision is to be an Energy Provider that utilizes "best in class" people, processes, and technology to lead the marketplace in sustainable energy solutions. Our customers will receive the greatest value by integrating an economic and environmental balance into the products and services EPLC delivers to them. As an Energy Provider, EPLC will be a community leader in ensuring that environmental stewardship is a vital component of our services and to increase customer awareness of proper energy utilization and management.

1.2.3 EPLC's Business Plan Summary

EPLC's plans are an outcome of its strategic and business planning efforts, enhanced asset management and capital expenditure planning processes, multi-faceted customer engagement, and coordinated planning with third parties. EPLC developed its plans to address and appropriately balance the needs and preferences of its customers, its distribution system requirements, and relevant public policy objectives.

Building on prior Cost of Service themes, and in recognition of key challenges faced by EPLC, as well as in the Ontario market as a whole, this plan contemplates shifts that could not have been anticipated when prior plans or even the distribution system, as they exist today, were designed and built. Understanding the pace and significance of this change drives the activities, planning, and costs that underpin this plan. Embracing this industry evolution is a key pillar in EPLC's strategy and has a significant impact on the planning process at the LDC.

EPLC has developed its business plan to address the expectations of the Ontario Energy Board ("OEB")'s "Handbook for Utility Rate Applications," issued October 13, 2016. EPLC's business planning and budgeting cycle typically occurs in the fall of each year, at which time a one-year budget and additional two-year forecast is prepared based on strategic initiatives, anticipated growth, and planned capital spend. The business plan and the associated financial documents are built by department managers, consolidated by the Finance Team, and presented for review by the President and CEO prior to being presented to the Board for review and final approval.

Preparation of the 2025 rate application required EPLC to prepare the 2024 and 2025 business plans and associated budgets/forecasts in quick succession and earlier than is typical. EPLC completed its 2024 and 2025 business plan and 2024 budget in November of 2023; and those plans and budgets were presented to the Board of Directors December 6, 2023, at which time they were approved. The 2024-2025 Business Plan is attached herein as Attachment 1-A.

EPLC Business Plan Themes

In this section, EPLC provides a plain language summary of the goals that inform this Application.

In recognition of the ongoing transformation of the Ontario electricity sector and the specific impacts that electrification brings to the customers of Essex Powerlines Corporation, the multi-year strategy of EPLC is defined as ***Powering Forward***. Under pressures of increased electrification and a growing customer base, Essex Powerlines has devised strategies built on three main pillars that inform areas of focus and activity. The pillars: Customer Focus, Reliability, and Powering Growth are the main drivers of activities at the distributor. These themes inform planning, decisions, and execution and will serve both required maintenance activities alongside evolution and innovation in the distribution system.

Customer Focus is a top priority for EPLC and informs decisions that are made at all levels of the distributor's operations. The customer-centric culture at EPLC is evident through ongoing customer engagement activities and community outreach including satisfaction and safety surveys; technology solutions leveraged to enhance the customer experience, such as a chat bot and outage center to inform customers of outage occurrences and restoration times on the customer portal; and an omni-channel approach to communication and feedback through multiple channels such as social media, press releases, and email. Through consultation with relevant parties and planning initiatives, EPLC anticipates growth to a total customer count of 34,958 which is an increase over the 2023 actual customer count of 34,362. As EPLC's customer base continues to grow, the distributor must remain vigilant in planning and executing all activities through the lens of customer satisfaction.

Reliability is another of the key strategic pillars in EPLC's business plan. Through customer engagement initiatives, EPLC customers have expressed a continued interest in improved reliability, and with known increased electrification on the horizon, this will become an even higher priority. As detailed in numerous industry reports, there are concerns about the level of electrification and increasing demand which will lead to reduced reliability if action is not undertaken to consider those needs in planning. For example:

"Forecasted growth in electricity demand in Windsor-Essex and Chatham-Kent is significant."[1]

"Significant growth in the greenhouse sector in the Windsor-Essex region is expected to exceed existing transmission system capacity."[2]

"Local constraints in Windsor-Essex and Chatham restrict the ability to transport power to the entire West Zone."[3]

"Electricity demand in the region, particularly in Kingsville-Leamington, is growing rapidly due to agriculture and manufacturing development."[4]

"Demand is expected to exceed capacity"[5]

Thus, it is essential that EPLC plans for additional capacity requirements and rises to the challenges that will be faced in the near future. With current reliability statistics (both SAIDI and SAIFI) below OEB published distributor targets, EPLC is highly aware that this is an area of risk. Specific plans in this Application are aimed at addressing that risk.

Powering Growth is the third strategic pillar in the business plan and is intended to focus on activities at EPLC that support the ongoing delivery of power as required, plus enable the evolution of EPLC to accommodate new opportunities due to growth of the customer base and to handle new challenges that will arise out of electrification. Achieving this strategic objective will require innovation and investments in scalable technology that will enable EPLC to meet increasing demand both flexibly and seamlessly. These necessary investments must be made prudently and to match pace with the Distribution System Plan (DSP) published as part of this Application.

These themes come together in this Application through an outline that defines how EPLC can operate within the broader market but also leverage flexibility that is available locally to meet current and future needs, and thereby relieve constraints, deliver cost effective energy, and create a more local, although still very connected, modernized distribution system.

Details of specific initiatives can be found in the appropriate sections of the Application, and they are summarized here as the main initiatives that EPLC plans to undertake to achieve their strategy:

1. Expand Control Room Collaborative Work
    a. Broaden the use of the SmartMAP implementation and leverage its improved capabilities in coordination with control room activities. With new functionality that

[1] Powering Ontario's Growth, Ministry of Energy, 2023. Powering Ontario's Growth.
[2] Reliability Outlooks (July 2022 to December 2023, and October 2023 to March 2025), IESO 2022 and 2023, p. 31.
[3] Annual Planning Outlook, IESO 2020 and 2022, p.39.
[4] Windsor-Essex Regional Planning and IRRP (Integrated Regional Resource Plan), IESO 2019-2023.
[5] Windsor-Essex Regional Planning and IRRP (Integrated Regional Resource Plan), IESO 2019-2023.

can detect electric vehicles, SmartMAP continues to be an important tool in the evolution of EPLC's distribution system;

b. To realize synergies and costs designed into this Application in the area of control room and how a control room can be leveraged in a broader sense to recognize and optimize available local flexibility of supply;

c. To expedite responses to, and recovery from, unplanned and/or severe weather events that are increasing in frequency and severity.

2. Invest in Automation
    a. Customer communication automation to improve the overall customer experience and timeliness of interactions;
    b. Process automation to reduce (with the goal to eliminate) manual processes across multiple departments so that resource efforts can be focused on modernization in essential areas of distribution system planning and operation. The outcome here is a real-time distribution system and energy management planning process which is achieved in the follow phases:
        1. Automation of existing DSP process
        2. Map Based design estimating
        3. Digital Work Packages
        4. Ongoing load forecasting - critical for the consideration of electrification forecast and known constraints in the province and in Windsor-Essex specifically.
3. Invest in Technology
    a. Invest in AMI 2.0 and self-healing grid devices; leveraging advanced technology to improve reliability, reduce outage duration, and protect assets.
    b. Invest in systems and software that permit ongoing improvements to distribution system analytics - short-, mid- and long-term benefits, such as, outage management, distribution system planning and prioritization, condition-based asset planning
4. Integrate PowerShare, EPLC's DSO pilot into the rates and operating activities for the planned duration of the pilot project, and anticipate/plan for ongoing DSO activities in the distribution sector in the future.

The key elements of the Application will now be discussed:

1.2.4 Revenue Requirement

EPLC is requesting approval of its proposed service revenue requirement in the amount of $19,494,342, an increase of 50.3% over the 2018 Board Approved Amount of $12,872,964. Table 1-1 below shows a comparison of the Revenue Requirement calculations between the 2018 Board Approved Proxy and the 2025 Test Year.

Table 1-1: Service Revenue Requirement

Description	Last Rebasing Year - 2018 OEB Approved	2025 Test Year	Variance $	Variance %	Reference
Revenue Requirement					
OM&A, including LEAP,& Property Taxes	$7,287,493	$10,356,735	$3,069,242	42.1%	Exhibit 4
Depreciation	$2,122,219	$4,050,033	$1,927,814	90.8%	Exhibit 2
Payments in Lieu of Corporate Income Taxes (PILs)	$221,683	$197,057	($24,626)	-11.1%	Exhibit 6
Return on Debt	$1,252,363	$1,815,791	$563,428	45.0%	Exhibit 5
Return on Equity	$2,089,206	$3,074,726	$985,520	47.2%	Exhibit 5
Total	$12,972,964	$19,494,342	$6,521,378	50.3%	
Rate Base	$58,033,511	$83,461,606	$25,428,095	43.8%	

- OM&A has increased 42.1% over 7 years or an average of 6.0% per year. The OM&A costs in the 2025 Test Year reflect the resourcing mix and work activities required to meet customer expectations, growth, and broader public policy requirements. The primary reasons for this increase are higher levels of General Administration costs in support of work programs, inflation impacts on labour and non-labour costs, and increased costs in support of the expanding customer and asset base. OEB inflationary factors during this same time period total 23.29% compounded, while inflation on many distribution system components has increased at significantly higher rates. Also included are the costs of new initiatives in support of EPLC's strategic objectives, infrastructure development, staff resourcing, and succession planning, new systems, and control room operations being partially insourced to best support the distribution system.
- Depreciation has increased as EPLC has continued to invest in the distribution system and particularly in technologies that improve efficiency, reliability, and automation of that system. When these investments are made in technology solutions, depreciation is realized over 5 years instead of the 40 or 50 year life that is the traditional service life for distribution assets and this increases the amount of annual depreciation.
- The 2018 OEB Approved average net fixed asset value was $52,423,876, compared to $77,171,797 in the 2025 Test Year. Details with respect to the increases in the net fixed assets are provided in evidence in Exhibit 2. As a result of EPLC's net assets growing by $24,747,921, there has been an increase on the return on Rate Base from in-service capital additions since the last Cost of Service Application. This has necessitated the borrowing of additional external funds to finance the capital investment, further increasing the return on debt. This is further discussed in Exhibit 5.
- In the 2025 Test Year, EPLC seeks a Return on Equity of 9.21% (the current Board approved rate). EPLC acknowledges that the parameter is subject to further update.

1.2.5 Load Forecast Summary

EPLC's load forecast has been prepared using the same methodology as was approved by the OEB in its 2018 Cost of Service proceeding. EPLC once again engaged Elenchus Research Associates ("Elenchus") to support its 2025 Test Year load forecast.

EPLC prepared its Application based on a weather normalized load forecast by customer class and monthly customer class actual consumption for the weather sensitive customer classes, being the Residential, General Service< 50 kW and General Service 50-999 kW customer classes, using the regression analysis and by average usage and forecasted customer growth for the non-weather sensitive customer classes. The consumption of the metered customer classes was adjusted for conservation and demand management results of persistent programs.

Table 1-2 below summarizes the differences between the 2018 OEB Approved load forecast and the 2025 Test Year proposed load forecast.

Table 1-2: 2018 OEB Approved vs 2025 Test Year Proposed Load Forecast

Rate Class	2018 OEB Approved			2025 Test Year			Difference		
	Volumes	kWh/kW	Customers / Connections	Volumes	kWh/kW	Customers / Connections	Volumes	kWh/kW	Customers / Connections
Residential	234,935,416	kWh	27,784	284,634,106	kWh	29,454	49,698,690	kWh	1,670
General Service < 50 kW	64,810,159	kWh	1,997	70,835,308	kWh	2,098	6,025,149	kWh	101
General Service > 50 kW to 4999 kW	448,468	kW	217	698,414	kW	235	249,946	kW	18
Unmetered Scattered Load	1,554,368	kWh	141	1,383,562	kWh	123	(170,806)	kWh	(18)
Sentinel Lighting	2,080	kW	173	716	kW	216	(1,364)	kW	43
Street Lighting	7,877	kW	2,758	7,372	kW	2,828	(505)	kW	70
Embedded Distributor	80,869	kW	3	90,871	kW	4	10,002	kW	1
Total	301,839,237		33,073	357,650,349		34,958	55,811,112		1,885

The 2025 Test Year Load Forecast has been developed based on historical data trends and ongoing electrification and planned economic development, and in consideration of 200 amp service set out in the OEB Staff Bulletin: OEB Staff Bulletin Residential Customer Connections. Customer counts are average.

1.2.6 Rate Base and Distribution System Plan (DSP)

EPLC is proposing a rate base of $83,461,606 for the 2025 Test Year. This is an increase of $25,428,096 or 44% over the 2018 OEB approved rate base.

Table 1-3: 2025 Proposed Rate Base

Description	2025 Test Year
Gross Fixed Assets Opening	$125,838,698
Gross Fixed Assets Closing	$135,673,715
Average Gross Fixed Assets	$130,756,206
Accumulated Depreciation Opening	$51,664,637
Accumulated Depreciation Closing	$55,504,181
Average Accumulated Depreciation	$53,584,409
Average Net Book Value	**$77,171,797**
Working Capital	$83,864,121
Working Capital Allowance %	7.5%
Working Capital Allowance	**$6,289,809**
Rate Base	**$83,461,606**

Table 1-4 below provides a summary of EPLC's Rate Base from the 2018 OEB approved amounts, includes 2018 – 2023 Actual amounts and proposed 2024 Bridge Year and 2025 Test Year amounts.

Table 1-4: 2018 OEB Approved – 2025 Test Year Rate Base

Description	2018 OEB Approved	2018 Actual	2019 Actual	2020 Actual	2021 Actual	2022 Actual	2023 Actual	2024 Bridge Year	2025 Test Year
Gross Fixed Assets Opening	$83,405,332	$83,405,332	$86,939,488	$93,025,227	$98,194,189	$103,393,085	$109,018,679	$116,531,711	$125,838,698
Gross Fixed Assets Closing	$88,336,575	$86,939,488	$93,025,227	$98,194,189	$103,393,085	$109,018,679	$116,531,711	$125,838,698	$135,673,715
Average Gross Fixed Assets	$85,884,454	$85,172,410	$89,982,358	$95,609,708	$100,793,637	$106,205,882	$112,775,195	$121,185,204	$130,756,206
Accumulated Depreciation Opening	$32,267,050	$32,277,000	$34,102,060	$36,492,489	$39,123,404	$41,954,694	$44,911,750	$48,130,872	$51,664,637
Accumulated Depreciation Closing	$34,654,106	$34,102,060	$36,492,489	$39,123,404	$41,954,694	$44,911,750	$48,130,872	$51,664,637	$55,504,181
Average Accumulated Depreciation	$33,460,578	$33,189,530	$35,297,274	$37,807,946	$40,539,049	$43,433,222	$46,521,311	$49,897,754	$53,584,409
Average Net Book Value	**$52,423,876**	**$51,982,880**	**$54,685,083**	**$57,801,762**	**$60,254,588**	**$62,772,660**	**$66,253,884**	**$71,287,450**	**$77,171,797**
Working Capital	$74,795,132	$64,968,270	$69,346,212	$80,539,205	$73,109,420	$72,093,060	$70,174,771	$76,990,805	$83,864,121
Working Capital Allowance %	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%	7.5%
Working Capital Allowance	**$5,609,635**	**$4,872,620**	**$5,200,966**	**$6,040,440**	**$5,483,206**	**$5,406,979**	**$5,263,108**	**$5,774,310**	**$6,289,809**
Rate Base	**$58,033,511**	**$56,855,500**	**$59,886,049**	**$63,842,202**	**$65,737,795**	**$68,179,640**	**$71,516,992**	**$77,061,760**	**$83,461,606**
% Change (year over year)		-2.0%	5.3%	6.6%	3.0%	3.7%	4.9%	7.8%	8.3%

Gross Capital Expenditures proposed for the 2025 Test Year are $11.303 million (excluding capital contributions). This represents a $5.111 million increase over the 2018 OEB approved capital expenditures of $6.192 million, an 83% increase. Capital contributions have increased by $301,000, for a net increase in capital spending of $4.810 million. Table 1-5 below, OEB Approved vs 2025 Test Year Capital Expenditures, provides a further breakdown of Capital Expenditures by category.

Table 1-5: OEB Approved 2018 Capital Expenditures vs 2025 Test Year Capital Expenditures

Category	Historical ($ '000) 2018	Forecast ($ '000) 2025	Difference ($'000)	Difference %
System Access (Gross)	$2,009	$2,314	$305	15.2%
System Renewal (Gross)	$2,831	$3,214	$383	14%
System Service (Gross)	$900	$2,532	$1,632	181%
General Plant (Gross)	$452	$3,244	$2,792	618%
Gross Capital Expenses	$6,192	$11,303	$5,111	83%
Contributed Capital	($1,167)	($1,468)	($301)	26%
Net Capital Expenses after Contributions	$5,025	$9,835	$4,810	96%
System O&M	$2,500	$3,189	$689	28%

EPLC's Distribution System Plan (DSP) has objectives that align with, and support, the four key objectives from the OEB's Renewed Regulatory Framework for Electricity Distributors: A Performance-Based Approach ("RRFE"). In alignment with these four outcomes, EPLC's overarching objective of its five (5)-year plan is to become an energy enablement management company that provides a flexible and modernized smart grid, allowing for DER enablement and consumer choice as it relates to electrification and conservation. EPLC's progressive approach enables them to be adaptive through the energy transition and meet the evolving needs of the sector and its customers. To achieve these goals, EPLC will continue with the following key objectives:

- Continue to build upon and enhance the consumer experience through the development of an outage notification system to include push notifications, development of an app, move in/move out forms, and an enhanced consumer engagement portal.
- Continue to drive costs down with the implementation of modern management techniques and other process improvements.
- Expand Control Room Collaborative work with similar, like-minded utilities by:
    - Broadening the use of SmartMAP implementation and leveraging its improved capabilities in coordination with control room activities.
    - Integrating full SCADA functionality with SmartMAP.
    - Realizing synergies and costs of the control room and how a control room can be leveraged to recognize and optimize available local flexibility and supply; and
    - Expediting response to, and recovery from, unplanned and/or severe weather events that are increasing in frequency and severity.
- Invest in software systems to streamline and automate daily work tasks including, but not limited to:
    - tracking and recording of asset condition data,
    - inputting of time entry information,
    - job cost tracking,
    - inventory management,
    - job kitting,
    - design and accurate estimation of planned work, and

    - the recording of all asset information in the Geospatial Information System ("GIS"), among others
- Enhance SmartMAP (geospatial information system tool) to include SCADA, improve on the outage management system, and increase utility visibility.
- Enable non-wires solutions in EPLC service territory through a local energy market.

System Access and System Service projects are planned to meet the ongoing and evolving needs of the distribution system. They are planned and paced in the 5-year DSP to accommodate maintaining the distribution system as necessary to achieve reliability improvements and service customers, as well as to address the evolving customer base of EPL and their needs as expansion and economic development in the region drive much of this activity. Planned expansion for residential development along with several significant greenhouse expansions occurring on the cusp of the start of this DSP have been considered in this planning. Additionally, impacts of electrification are becoming evident and require consideration as EPLC has been advised of plans for an industrial natural gas conversion within its service territory.

System Service investments will accommodate much of the forward-looking distribution system planning that EPLC plans to undertake during the period of this DSP. These plans include acquisition of assets from Hydro One Networks Inc. that will improve reliability, by permitting EPLC to better manage its access to power and reduce loss of supply occurrences that continue to be the main cause of outages and reduce reliability to EPLC's customer base. Specifically, these assets are sections of the Malden M& (in Amherstburg) and sections of the Leamington M24 and M27. Other investments in this category include the balance of investments in self-healing grid assets that with aid in automating and streamlining switching operations again, with the goal of improving reliability and recovery from outage events. Work on the self-healing grid is funded through the NRCAN Strategic Renewable Energy Pathways (SREP) program. System Service is also the category in which the Distribution System Operator (DSO) activities are found, with investments planned in measurement and verification equipment necessary to operate a local energy market pilot project, PowerShare, that is funded by the OEB and the IESO through the Grid Innovation Fund.

General Plant investments are the backbone of EPLC's 24/7 operations. Expenditures in this category are driven by the need to modify, replace, or add to assets that are not part of the distribution system but support EPLC's regular operations. The projects include, but are not limited to, necessary building repairs such as HVAC and roof replacements, vehicle purchases based on a fleet condition assessment, and investments in software to perform maintenance and cybersecurity enhancements, as well as enable EPLC staff to effectively perform activities such as billing and responding to customer queries in an efficient and reliable manner. The building maintenance is necessary to ensure that EPLC staff have a safe and healthy work environment from which to maintain the distribution system and serve EPLC customers. Vehicle purchases also enable servicing the distribution system. More details of projects that contribute to General Plant expenditures are described below.

Investments in software are key to achieving EPLC's overall goal of to becoming an energy management enablement company that provides a flexible and modernized smart grid, allowing for DER enablement and consumer choice as it relates to electrification and conservation. These investments include enhancing control room tools to enable full visibility, efficiency and automation; streamlined customer interactions for an enhanced customer experience; they contribute to the evolution of EPLC as a distribution company as they prepare for electrification, digitalization and economic development. EPLC has proposed IT investments to address hardware and software needs. Modern IT infrastructure is a critical component of EPLC's operations needed to ensure security, resiliency, and effectiveness. EPLC is seeking to invest in IT hardware and software to improve the efficiency and effectiveness of its activities, from interacting with customers to conducting operations in the field. Additionally, advances in the energy sector require frequent IT technology upgrades to match the pace of the evolving industry and enhanced customer expectations. Synonymous with advancements in technology is the increased risk of cybersecurity threats. Utilities persistently face challenges of delivering secure, timely, and technologically advanced solutions within an increasingly complex IT landscape. Capital forecasts for IT investments include the replacement of existing IT hardware and software, as well as new investments in technologies that support the goals of the organization. Mostly, EPLC's IT hardware and software plan focuses on replacing end-of-service life assets and ensuring reliable and secure infrastructure. Some of the major investments that EPLC plans to undertake in the forecast period include:

- CIS Upgrade/Replacement- this is required to ensure EPLC can meet its future billing requirements and customer engagement, as well as being critical to its requirements of becoming a DSO. EPLC is seeking a CIS platform that acts as a unified solution, bridging customer care and utility operations in a central platform. This includes a CIS platform that promotes utility grid modernization and ultimately elevates the customer experience by providing more frequent and reliable customer data, integrating a user-friendly and connective customer platform, and allowing for tailored communications and engagement to customers via preferred channels.
- GIS Utility Network Design Upgrade/Replacement- EPLC's current GIS model is nearing end-of-life as per third-party/vendor assessment. Upgrades are critical to utility operations.
- OMS & SCADA enhancements- upgrades are required to enable EPLC to gather additional data to meet future energy demands and enhance customer interactions. In addition, upgrades will enable EPLC to achieve energy transition goals.
- Server Upgrades- EPLC's existing hardware and technology is nearing end-of-life for server hosts, as per third-party/vendor assessment. Specifically, its VMWare is nearing end-of-life and end of support. To stay compliant with cybersecurity requirements and reduce operational risk, these upgrades are necessary.
- Internet Upgrade- EPLC is exploring redundant internet supply to strengthen business continuity.
- Asset Management & AI- EPLC plans to invest in its asset lifecycle management and security requirements for software upgrades.

- GP Accounting Software Replacement- EPLC's current accounting software is at its end-of-life and will no longer be supported by its third-party vendor. As such, replacement is necessary for continued operation of EPLC.
- Other minor hardware and software components, including but not limited to, general day-to-day hardware and software upgrades and replacements are necessary to reduce cybersecurity incidents and ensure EPLC employees have proper IT hardware and software to complete work effectively and efficiently.

Investments in EPLC's Building and Fixtures entail general repairs, replacements, and upgrades within EPLC's facilities to facilitate the safe and efficient work of its personnel. Planned investments are in part due to a building assessment that was completed in 2016 by a third-party who provided observations and reported on the physical conditions of EPLC's building and property. EPL was prudent in monitoring building components based off the 2016 assessment and ensuring replacements were made where feasible and appropriate. Items that were not replaced or repaired were continually monitored by both internal staff and external contractors, and as a result, constitute the building's five-year plan for the forecasted period. Other items will continually be reviewed within the forecast period based off the results of the planned 2025 assessment. The following investments are planned for 2025:

- HVAC replacement based on increasing maintenance costs and end-of-life criteria.
- Roof rehabilitation based on recommendations from a third-party assessment in 2022 (attached in Exhibit 2- DSP)
- Building upgrades based on inspection.

Investments in EPLC's Transportation and Fleet are required over the forecast period. Vehicles are an essential component to EPLC operations, as they are necessary for the timely restoration of power during planned and unplanned outages, the efficient construction and maintenance of a distribution system, and the safety of employees and the public. EPLC currently controls and manages 39 fleet vehicles, comprised of private vehicles, light trucks, heavy trucks, and trailers, as well as other miscellaneous equipment to support the system. EPLC maintains a multi-year capital plan for its fleet and mobile assets. EPLC follows its Fleet Purchasing Policy to determine when individual vehicles need to be replaced. Each individual fleet asset is assessed based on vehicle age, mileage, engine and PTO hours, maintenance and inspection analysis, use-case requirement, and changing regulations. Additionally, EPLC utilizes IRFS standard which indicates a typical useful life of 8 years for small fleet vehicles and 12 years for CVOR fleet vehicles. Trucks that are to be replaced in the forecast period are nearing end-of-life and require substantial maintenance, in alignment with EPLC's Fleet Purchasing Policy. Some of the larger increases observed in fleet expenditures are due to the following explanations:

- Chassis costs for heavy trucks have increased due to increased raw material, labour, and freight costs. Additionally, many chassis suppliers are on fleet allocations, thereby creating a supply versus demand market that is not favourable to the end user (in this case, EPLC).
- Overall increase in pricing in small fleet (pick-ups) noted due to decrease in available inventory.

- Equipment/body builders and upfit suppliers (bucket/radial boom derricks) to be mounted on heavy truck chassis have increased their pricing as a result of increased manufacturing costs related to raw materials, labour, and freight.
- COVID-19 pandemic had an adverse effect on many workforces. Many of EPLC's suppliers had trouble with bringing back their employees following the pandemic and/or keeping employees. This created decreased production and increased costs throughout their manufacturing sites.
- Overall, inflation, supply chain, and material costs are the major cost factors that have affected these assets.

Investments in EPLC's Tools includes the purchase of various tools necessary to carry out the operations and maintenance activities of the engineering and operations departments. This includes, but is not limited to specialized cutting tools, trailers for poles or reels of wire, and stores equipment to improve the operational efficiency of the field crew, lower operational costs, or reduce potential safety risks. Equipment is purchased on an as-needed basis depending on the type of work required. EPLC's program budget allows for the replacement of tools and equipment that have reached their end of typical useful life (due to deterioration, substandard performance, and/or functional inefficiencies), for the purchase of additional tools and equipment needed to serve EPLC's growing customer base, as well as for unplanned replacements of tools and equipment due to premature failure. Investments under this program vary year to year based on specific needs. For the 2025 test year, the following tools will be purchased:

- Battery operated crimpers and cutters.
- Rubber cover-up.
- Rubber gloves.
- Grounds.
- Various live line tools including extendable switch stick, shotgun/grip-all sticks and load bust tools.
- Web and chain hoists.
- Fall arrest harnesses and lanyards.
- Powerline Technician pole climbing equipment.
- Live-line measurement tools including super beasts, phasing sticks, potential indicators, and ammeters.

1.2.7 Operations, Maintenance and Administration Expenses

Table 1-6: 2025 Test Year vs. 2018 OEB Approved

Description	2018 OEB Approved	2025 Test Year	Variance
Operations	$1,353,708	$1,890,101	$536,393
Maintenance	$1,518,463	$1,298,792	($219,671)
Subtotal	**$2,872,171**	**$3,188,893**	**$316,722**
Customer Service	$1,542,573	$2,000,474	$457,901
Administration	$2,830,211	$5,123,368	$2,293,157
Subtotal	**$4,372,784**	**$7,123,842**	**$2,751,058**
Total OM&A	**$7,244,955**	**$10,312,735**	**$3,067,780**
% Change			42.3%

As shown in Table 1-6, EPLC's increase in OM&A spending from the 2018 OEB Approved to the 2025 Test Year amounts to $3,067,780, or 42.3 % over 7 years or an average of 6.0% per year. The OM&A costs in the 2025 Test Year reflect the resourcing mix and work activities required to meet customer expectations, growth, and broader public policy requirements. The primary reasons for this increase are higher levels of General Administration costs in support of work programs, inflation impacts on labour and non-labour costs, and increased costs in support of the expanding customer and asset base. Also included are the costs of new initiatives in support of EPLC's strategic objectives, infrastructure development, staff resourcing, and succession planning, new systems, and control room operations being partially insourced to best support the distribution system.

In Table 1-7 below, a summary of cost drivers shows that salaries, wages, and benefits are the most significant cost driver. This increase is reflective of overall trends in compensation, a job evaluation and compensation review along with the addition of several new positions planned to address areas of customer focus, technology and security, and control room engineering. The details of EPLC's workforce planning activities can be found in Exhibit 4.

Table 1-7: Primary Cost Drivers

Primary Cost Drivers 2018-2025	Total
Salaries, Wages and Benefits	$1,436,326
Materials	$978,717
Customer Billing and Collecting	$432,406
Computer Systems, Hardware and Software	$177,393
Building	$69,500
Administrative	$86,297
Outside Services incl tree trimming	($347,369)
Total	**$2,833,270**

EPLC's most recent contract with the IBEW expired on March 31, 2024, and EPLC is currently in the process of negotiating a new agreement. Costs and Models in this application have not been updated to reflect any anticipated new contractual obligations; EPLC has incorporated the most recent 2% annual increase as a placeholder.

With the most recent round of negotiations currently underway, at such time as negotiations are successfully concluded, EPLC will update all affected schedules to reflect new contractual amounts. It is expected that this will be completed during the interrogatory phase of the Application process.

1.2.8 Cost of Capital

EPLC has prepared its Application in accordance with the Report of the Board on Cost of Capital for Ontario's Regulated Utilities (the "Cost of Capital Report") dated December 11, 2009, to determine its capital structure and relied on the Board's letter titled *Cost of Capital Parameter Updates for 2024 Applications* dated October 31, 2023, for the cost of capital parameters.

EPC will update its evidence to reflect future Board cost of capital parameters for rates with more recent effective dates, prior to the issuance of the Board's decision on this Application. EPLC is not proposing any deviation from the Board's cost of Capital Methodology.

Table 1-8: Cost of Capital and Capital Structure

Test Year: 2025

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$46,738,500	3.44%	$1,607,804
2	Short-term Debt	4.00%	$3,338,464	6.23%	$207,986
3	**Total Debt**	60.0%	$50,076,964	3.63%	$1,815,791
	Equity				
4	Common Equity	40.00%	$33,384,643	9.21%	$3,074,726
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$33,384,643	9.21%	$3,074,726
7	**Total**	100.0%	$83,461,607	5.86%	$4,890,516

Last OEB-approved year: 2018

Line No.	Particulars	Capitalization Ratio		Cost Rate	Return
		(%)	($)	(%)	($)
	Debt				
1	Long-term Debt	56.00%	$32,498,766	3.69%	$1,199,204
2	Short-term Debt	4.00%	$2,321,340	2.29%	$53,159
3	**Total Debt**	60.0%	$34,820,107	3.60%	$1,252,363
	Equity				
4	Common Equity	40.00%	$23,213,404	9.00%	$2,089,206
5	Preferred Shares		$ -		$ -
6	**Total Equity**	40.0%	$23,213,404	9.00%	$2,089,206
7	**Total**	100.0%	$58,033,511	5.76%	$3,341,570

1.2.9 Cost Allocation and Rate Design

Cost Allocation

The data used in the updated cost allocation study is consistent with EPLC's cost data that support the proposed 2025 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 EPLC, its engineering records, and its customer and financial information systems.

In the March 31, 2011, Cost Allocation Report, the Board established what it considered to be the appropriate ranges of revenue-to-cost ratios which are summarized in Table 1-9 below. In addition, Table 1-9 provides EPLC's revenue-to-cost ratios from the 2018 Application, the updated 2025 cost allocation study and the proposed 2026-2027 ratios.

Table 1-9: Revenue-to-Cost Ratios

Rate Class	Previously Approved 2018 Ratios	Status Quo Ratios	2025 Proposed Ratios	2026 Proposed Ratios	2027 Proposed Ratios	2028 Proposed Ratios	Policy Range
Residential	96.20%	91.70%	94.20%	94.21%	94.17%	94.15%	85 - 115
GS<50	116.80%	119.90%	119.90%	119.92%	119.92%	119.92%	80 - 120
GS>50	103.70%	136.50%	120.00%	120.00%	120.00%	120.00%	80 - 120
Street Lights	120.00%	82.50%	94.20%	94.21%	94.17%	94.15%	80 - 120
Unmetered Scattered Load	120.00%	140.60%	120.00%	120.00%	120.00%	120.00%	80 - 120
Sentinel Lights	120.00%	40.30%	55.40%	63.15%	74.24%	80.00%	80 - 120
Embedded Distributor	120.00%	158.00%	120.00%	120.00%	120.00%	120.00%	80 - 120

In absence of any rate mitigation there would be total bill impacts in excess of 10% for the Sentinel lighting rate class. Sentinel Light distribution rates increase in 2025 - 2027 so the total bill impact is 10%, and in 2028 distribution rates increase so it reaches the 80% revenue-to-cost floor. The lower Sentinel Light rate increases in 2025 and 2026 are offset by small increases to Residential and General Service < 50 rates.

EPLC is not proposing any new rate classes in this Application.

Rate Design

EPLC proposes to maintain the fixed/variable proportions assumed in the current rates to design the proposed monthly service and the distribution of volumetric charges.

Table 1-10: Proposed Distribution Charges

Rate Class	Proposed Fixed Distribution Charge	Billing Determinant	Proposed Volumetric Charge
Residential	$ 36.66	kWh	
GS< 50kW	$ 44.69	kWh	$ 0.0177
GS> 50kW	$ 274.38	kW	$ 2.6620
Embedded Distributor	$ 563.14	kW	$ 1.2467
Street Light	$ 5.08	kW	$ 13.7715
Sentinel	$ 6.07	kW	$ 17.3835
USL	$ 10.10	kWh	$ 0.0315

The percentage changes for all classes reflect the overall increase in distribution costs. The notable change in the Sentinel Lighting class is the result of a correction to the allocation incorrectly applied in the 2018 rebasing Application (EB-2017-0039). In 2018, the billed demand figure used to calculate the rate was way high because of a cell reference error. The amount allocated to Sentinel Lights to be recovered through the variable charge was divided by this incorrect billed volumes figure that was approximately 3 times higher than it should have been, resulting in a rate that was about 3 times lower than it should have been. This material impact has been mitigated and as revenues from this class are low, there is no significant impact on other rates.

1.2.10 Deferral and Variance Accounts

As outlined in Exhibit 9, EPLC requests approval of the net disposition of Group 1, Group 2 and Other Deferral and Variance Accounts ("DVAs") in the amount of $(2,040,947) as a refund to customers. All dispositions are being requested using a twelve-month period, riders in effect from January 1, 2025, expiring December 31, 2025. This includes all Group 1 RSVA Accounts, Group 2 Deferral and Variance Accounts including Account 1508 Pole Attachment Variance, Account 1592 Accelerated CCA, and other Group 2 Accounts as described in Exhibit 9 proposed for disposal in this application. All riders have been calculated in accordance with the OEB's approved allocators, no deviations from the allocators are included in this application. The following tables show the allocators, balances requested for disposal and the resulting riders by Class.

Table 1-11: DVA Allocators, Balances, and Rate Riders

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.)

1550, 1551, 1584, 1586, 1595, 1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance (excluding 1589)	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL	kWh	273,030,318	-$ 846,857	- 0.0031
GS<50	kWh	67,947,538	-$ 201,796	- 0.0030
GS>50	kW	669,941	$ 113,336	0.1692
EMBEDDED DISTROBUTOR	kW	87,166	-$ 95,820	- 1.0993
STREETLIGHT	kW	7,071	-$ 6,809	- 0.9629
SENTINEL LIGHT	kW	687	-$ 734	- 1.0687
USL	kWh	1,327,158	-$ 3,871	- 0.0029
Total			**-$ 1,042,551**	

Rate Rider Calculation for Group 1 Deferral / Variance Accounts Balances (excluding Global Adj.) - NON-WMP

1580 and 1588

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 1 Balance - Non-WMP	Rate Rider for Deferral/Variance Accounts
RESIDENTIAL		-	$ -	-
GS<50		-	$ -	-
GS>50	kW	653,520	-$ 634,965	- 0.9716
EMBEDDED DISTROBUTOR		-	$ -	-
STREETLIGHT		-	$ -	-
SENTINEL LIGHT		-	$ -	-
USL		-	$ -	-
Total			**-$ 634,965**	

Rate Rider Calculation for Account 1580, sub-account CBR Class B

1580, Sub-account CBR Class B

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Sub-account 1580 CBR Class B Balance	Rate Rider for Sub-account 1580 CBR Class B
RESIDENTIAL		273,030,318	$ 47,650	0.0002
GS<50		67,947,538	$ 11,858	0.0002
GS>50		653,520	$ 25,451	0.0389
EMBEDDED DISTROBUTOR		87,166	$ 5,733	0.0658
STREETLIGHT		7,071	$ 407	0.0576
SENTINEL LIGHT		687	$ 44	0.0639
USL		1,327,158	$ 232	0.0002
Total			**$ 91,375**	

Rate Rider Calculation for RSVA Global Adjustment

Balance of Account 1589 Allocated to Non-WMPs

Rate Class (Enter Rate Classes in cells below)	Units	kWh	Allocated Global Adjustment Balance	Rate Rider for RSVA - Power - Global Adjustment
RESIDENTIAL	kWh	3,438,138	$ 12,582	0.0037
GS<50	kWh	13,594,945	$ 49,751	0.0037
GS>50	kWh	126,845,367	$ 464,196	0.0037
EMBEDDED DISTROBUTOR	kWh	34,244,754	$ 125,320	0.0037
STREETLIGHT	kWh	216,657	$ 793	0.0037
SENTINEL LIGHT	kWh	262,328	$ 960	0.0037
USL	kWh	745,395	$ 2,728	0.0037
Total			**$ 656,331**	

Rate Rider Calculation for Group 2 Accounts

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Group 2 Balance	Rate Rider for Group 2 Accounts
RESIDENTIAL	# of Customers	29,454	-$ 856,445	-$ 2.42
GS<50	kWh	67,947,538	-$ 213,139	-$ 0.0031
GS>50	kW	669,941	-$ 595,405	-$ 0.8887
EMBEDDED DISTROBUTOR	kW	87,166	-$ 103,040	-$ 1.1821
STREETLIGHT	kW	7,071	-$ 7,323	-$ 1.0355
SENTINEL LIGHT	kW	687	-$ 789	-$ 1.1493
USL	kWh	1,327,158	-$ 4,163	-$ 0.0031
Total			**-$ 1,780,304**	

Rate Rider Calculation for Accounts 1575 and 1576

Please indicate the Rate Rider Recovery Period (in months) **12**

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Accounts 1575 and 1576 Balances	Rate Rider for Accounts 1575 and 1576
RESIDENTIAL	# of Customers	29,454	$ 71,110	0.2012
GS<50	kWh	67,947,538	$ 17,697	0.0003
GS>50	kW	669,941	$ 49,436	0.0738
EMBEDDED DISTRIBUTOR	kW	87,166	$ 8,555	0.0981
STREETLIGHT	kW	7,071	$ 608	0.0860
SENTINEL LIGHT	kW	687	$ 66	0.0954
USL	kWh	1,327,158	$ 346	0.0003
		-	$ -	-
Total			**$ 147,817**	

Rate Rider Calculation for Account 1509

Please indicate the Rate Rider Recovery Period (in months) **12**

Rate Class (Enter Rate Classes in cells below)	Units	kW / kWh / # of Customers	Allocated Account 1509 Balance	Rate Rider for Account 1509
RESIDENTIAL	# of Customers	29,454	$ 76,235	0.22
GS<50	# of Customers	2,098	$ 13,976	0.56
GS>50	# of Customers	235	$ 15,037	5.33
EMBEDDED DISTRIBUTOR	# of Customers	4	$ 826	17.20
STREETLIGHT	# of Customers	28,228	$ 1,612	0.00
SENTINEL LIGHT	# of Customers	216	$ 165	0.06
USL	# of Customers	123	$ 344	0.23
Total			**$ 108,194**	

There are no new DVAs being requested in this Application. A new DVA was requested by EPLC in a separate Application (EB-2024-0096) on February 16, 2024.

DVAs that will no longer require activity and which are being requested to be discontinued are:

- 1595 Disposition and Recovery of Regulatory Balances (2018)
- 1508 Wireline Attachment Variance
- 1508 IFRS Implementation Deferral
- 1576 Accounting Changes Under CGAAP
- 1595 Accelerated CCA
- 1592 PILs variance

- 1592 HST ITC

The 1592 Accounts listed above currently contain offsetting balances that were intended to be eliminated (offset) following the prior COS filing and as that has not been done at that time, EPLC intends to make that entry prior to discontinuing use of the accounts going forward.

1.2.11 Bill Impacts

Table 1-12 below summarizes the bill impacts for EPLC's average customer by rate class. These proposed bill impacts are inclusive of the proposed distribution rates, load forecast, and disposition of deferral and variance accounts in this application.

Table 1-12: Bill Impacts

Description	kWh	kW	# of Connections	2024 Bill $	2025 Bill $	$ Difference	Total Bill Impact %	Distribution Bill Impact %
Residential	750		29,454	$ 137.24	$ 132.03	($5.21)	-3.80%	-13.46%
GS <50kW	2,000		2,098	$ 354.10	$ 332.20	($21.90)	-6.18%	-21.97%
GS >50kW	40,000	100	235	$ 6,001.58	$ 5,406.65	($594.93)	-9.91%	-43.11%
Embedded Distributor	200,000	50	4	$ 25,000.66	$ 23,170.74	($1,829.92)	-7.32%	-48.94%
Unmetered Scattered Load	115,297		123	$ 25,387.40	$ 23,182.79	($2,204.61)	-8.68%	-29.42%
Sentinel Lighting	21,861	60	216	$ 4,898.54	$ 5,388.91	$490.37	10.01%	122.74%
Street Lighting	202,800	614	2,828	$ 52,240.21	$ 51,414.52	($825.69)	-1.58%	-0.05%

The notable change in the Sentinel Lighting class is the result of a correction to the allocation incorrectly applied in the 2018 rebasing Application (EB-2017-0039). In 2018, the billed demand figure used to calculate the rate was way high because of a cell reference error. The amount allocated to Sentinel Lights to be recovered through the variable charge was divided by this incorrect billed volumes figure that was approximately 3 times higher than it should have been, resulting in a rate that was about 3 times lower than it should have been. This material impact has been mitigated and as revenues from this class are low, there is no significant impact on other rates.

1.3 Administration

1.3.1 Executive Certification

Please see Attachment 1-B for Executive Certification.

1.3.2 Primary Contact Information

The Applicant:

Essex Powerlines Corporation
2730 Highway #3,

Oldcastle, ON,
N0R 1L0

Primary Application Contact:

Grace Flood
Director of Finance and Regulatory Affairs
Phone: (519) 791-1481
Email: gflood@essexpowerlines.ca

1.3.3 Legal Representation

BLG (Borden Ladner Gervais LLP)
Bay Adelaide Centre, East Tower
22 Adelaide Street West, Suite 3400
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M5H 4E3
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Fax: 416-367-6749

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

All Application materials will be posted on the EPLC website and will also be communicated via our social media channels outlined below:

Website: www.essexpowerlines.ca
Twitter: http://www.twitter.com/essexpowerlines
Facebook: https://www.facebook.com/essexpowerlines
LinkedIn: https://www.linkedin.com/company/essex-powerlines-corporation

1.3.5 Statement of Publication

Essex Powerlines will follow the OEB's instructions regarding the Publication of Notice in relation to this Application. The Notice of Application will be published to Essex Powerlines' website, under the Regulatory Affairs section, as well as under the "News & Media" section:

- Essex Powerlines Website: https://essexpowerlines.ca/about/regulatory-affairs/
- Essex Powerlines News and Media: https://essexpowerlines.ca/news/

1.3.6 Material Impacts on Customers

The proposals set forth in this Application will change the rates for all customer classes; however, there are no proposed changes that will result in bill impacts which exceed the 10% total bill impact threshold and which would consequently have a material impact on customers.

1.3.7 Materiality Threshold

Section 2.0.8 – Materiality Thresholds of the Chapter 2 Filing Requirements states that the materiality threshold relates to the revenue requirement impact of the expenditure. EPLC's applicable materiality threshold is defined as 0.5% of distribution revenue requirement for a distributor since its distribution revenue requirement is greater than $10 million and less than or equal to $200 million. EPLC's distribution revenue requirement for 2025 in this Application is $ 18,388,098 which equates to a materiality threshold of $ 91,940. EPLC provides its materiality threshold used in its Application in Table 1-13 below. EPLC has applied the materiality threshold of $90,000 in its analysis throughout this Application. EPLC notes that throughout some sections, it has chosen to provide explanations for variances below its materiality threshold, where these explanations were necessary for meaningful analysis.

Table 1-13: Materiality Threshold

Description	2025 Test Year
Distribution Revenue Requirement	$18,388,098
Materiality Threshold 0.5%	$91,940

1.3.8 Bill Impacts for Notice of Application

EPLC provides Table 1-14 which includes Bill impacts (the bill impacts that result only from distribution cost changes per sub-total A of Tariff Schedule and Bill Impacts spreadsheet model) to be used for the Notice of Application.

Table 1-14: Bill Impacts Resulting from 2025 Rate Application

Description	kWh	$ Difference	Total Bill Impact %
Residential	750	$6.19	19.90%
GS <50kW	2,000	$7.09	9.50%

1.3.9 Form of Hearing

EPLC requests that this Application be disposed of by way of a written hearing.

1.3.10 Requested Effective Date of Rate Order

EPLC requests that the OEB make its Rate Order Effective January 1, 2025. In the event that the OEB is not able to provide a Decision and Rate Order in time for EPLC to implement its rates effective January 1, 2025, EPLC requests that the OEB declare EPLC's current rates interim effective January 1, 2025 and approve rate riders to recover the incremental revenue between the implementation date of the OEB's 2025 Rate Order and January 1, 2025.

1.3.11 Changes to Methodologies used in Previous Applications

The methodologies used in this Application are generally consistent with those applied in EPLC's 2018 Cost of Service application. EPLC has made changes as required as the Filing Requirements have evolved since those used in the 2018 Application.

EPLC has made some changes to its methodology for load forecasting to address the cessation of the Conservation First Framework for Conservation and Demand Side Management (CDM) and has changed the approach used to adjust the load forecast relating to CDM based on the latest OEB CDM Guidelines. In addition, EPLC has adjusted its load forecasting approach to address changes in customer load patterns resulting from the COVID- 19 Pandemic. Please refer to Exhibit 3 for a discussion of these items.

EPLC prepared the pro-forma projections for the 2025 Test Year in accordance with the same approach that was used when it prepared its 2018 Cost of Service rate application, except that rates for distribution and sales of electricity are now constant for the entire 2025 Test Year, since EPLC's rate year is now aligned with its fiscal year. In a letter dated March 9, 2022, EPLC made a request to defer rebasing of its rates for 8 months which would result in aligning the rate year with the fiscal year. The OEB granted this request in a letter dated March 9, 2022 (and granted a further one-year extension in a letter dated January 24, 2023).

1.3.12 OEB Directions from Previous Decisions and/or Orders

Below is a summary of directives from previous decisions and/or orders and a description of how such directives have been addressed by EPLC in this Application.

EB-2017-0039

In its last COS Settlement EPLC was directed:

"during each year in any IRM application prior to the next cost of service application or Custom IR application, in which it seeks to dispose of any deferral and variance accounts, it will file with its application an updated table (See Appendix F) providing the status of the Management Action Plan that was provided in the OEB Staff audit of Regulatory Accounting Procedures, Controls, and Oversight over Deferral and Variance Accounts report, dated April 2016."

EPLC filed the required action plan with each subsequent IRM Application and with the finalization of EPLC's 2024 IRM Application (EB-2023-0020), EPLC fully discharged this direction. The 2024 IRM proceeding approved the balances of account 1588 and 1589 for disposal on a final basis for all years 2017-2022 and noted that "Essex Powerlines also confirmed the implementation of the revised settlement procedures in relation to the OEB's guidance on August 31st, 2019, effective January 1, 2019".

EPLC has addressed this directive prior to this Application however it is noted that EPLC continues to follow the aforementioned settlement procedures in relation to the OEB's guidance on August 31st, 2019, effective January 1, 2019 and has brought forth the 2023 balances of accounts 1588 and 1589 for disposal in this Application.

1.3.13 Conditions of Service

EPLC's Conditions of Service are posted online on its website:

https://essexpowerlines.ca/about/regulatory-affairs/conditions-of-service/

EPLC confirms that the Conditions of Service are current. EPLC reviewed and updated its Conditions of Service in April 2024. There are no rates and charges linked in the Conditions of Service that are not in the distributor's Tariff of Rates and Charges. The following changes to the Conditions of Service have been made since the last Cost of Service application:

- EPLC contact information was updated to reflect current office address, phone number, website, and Twitter.
- A title page was added to the document.
- 100A to 200A conversion as updated throughout the document.
- Slight verbiage changes to the Introduction in Section 1.
- Slight verbiage changes to sections 1.6.1, 1.8, 2.1.1, 2.1.2, 2.1.4, 2.2, 2.3.1, 2.3.7.1, 2.3.7.2, 2.3.7.3, 2.4.1, 2.5.

- Referenced voltage guidelines in section 1.6.2.- Customer Rights.
- Referenced voltage offerings in section 1.7.2- EPLC Rights.
- Added new section 2.1.8- Connection of Non-Residential EV Charging Infrastructure- Electric Vehicle Supply Equipment (EVSE), as per the amendment to the DSc to facilitate connection of EV Charging Infrastructure (EB-2019-0207).
- Updated Section 2.3.4 to include 27.6/16kV.
- Section 2.3.5- Voltage Guidelines updated table per CSA CAN3-C235.
- Section 2.3.7.3- Interval Metering updated from 500 kilo-watt to 200 kilo-watt.
- Section 2.4.5- Payments and Late Payment Charges updated payment methods.
- Section 2.5- Customer Information updated to reflect existing customer tools.
- Section 3.1.1- Updated “Basic Service” as per OEB suggestion.

1.3.14 Corporate and Distributor Organizational Structure

Essex Power Corporation, incorporated on March 17, 2000, under the *Business Corporations Act* (Ontario), is owned by four municipal shareholders; the Town of Amherstburg (14.26%), the Town of LaSalle (33.25%), the Municipality of Leamington (26.06%), and the Town of Tecumseh (26.44%). While equity percentages differ for each shareholder, they each hold equal voting rights. Essex Power Corporation is the parent holding company of a regulated local distribution company, Essex Powerlines Corporation and an unregulated company, Essex Energy Corporation.

Essex Powerlines Corporation is a regulated local distribution company that is a wholly owned subsidiary of Essex Power Corporation. EPLC services the four non-contiguous areas of its shareholder municipalities under a Distribution License (ED-2002-0499). EPLC services only portions of Amherstburg, Leamington and Tecumseh, and services the entire Town of LaSalle.

Essex Energy Corporation is a wholly owned unregulated subsidiary of Essex Power Corporation. Essex Energy Corporation (“EEC”) is a dynamic energy technology company providing various services and technology related solutions to electrical utilities, generators, transmitters, and consumers across North America.

Figure 1-1 below sets out the corporate structure of Essex Power Corporation.

Figure 1-1: Essex Power Corporation Corporate Structure

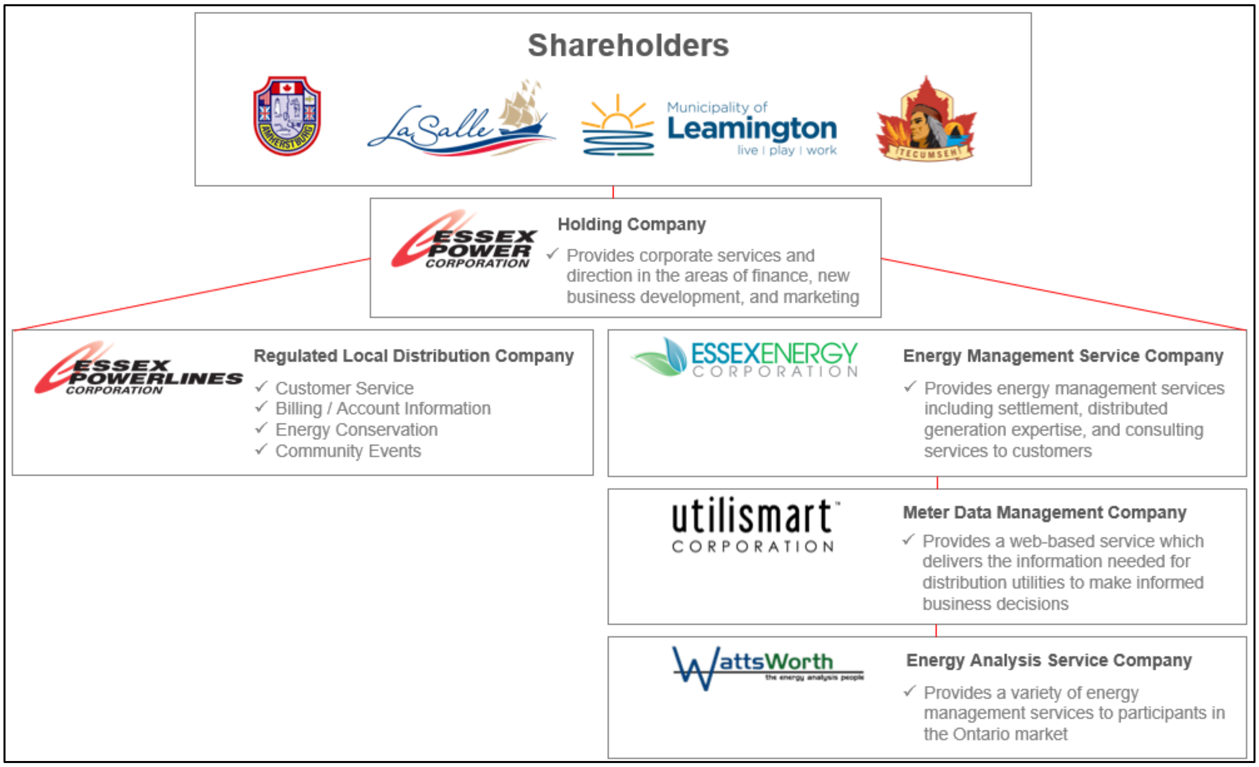
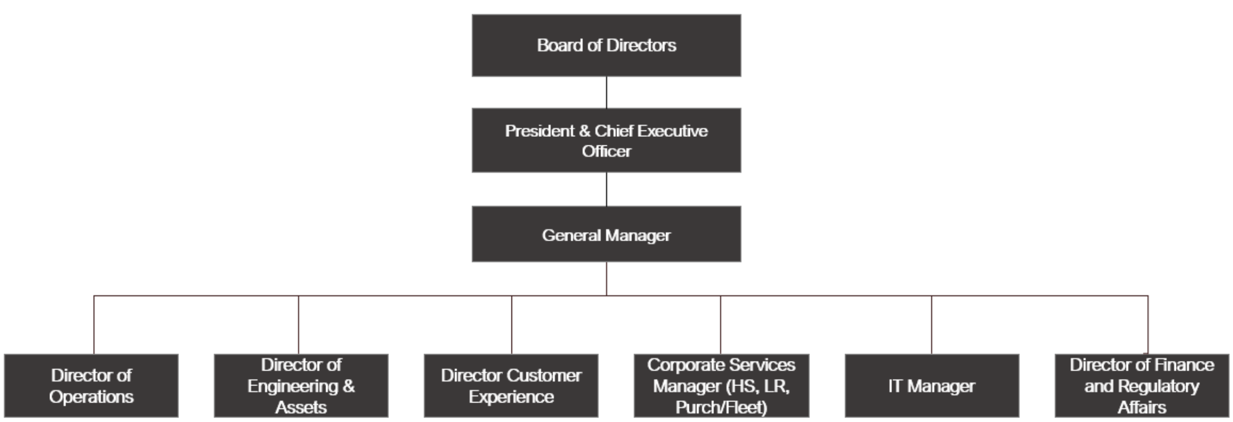


Figure 1-2 below sets out the organizational structure of EPLC showing the main units and executive and senior management positions.

Figure 1-2: Organizational Structure



The Board of Directors of Essex Power Corporation is comprised of 8 shareholder appointed representatives. Each of the 4 shareholders appoints an elected municipal representative and a non-elected member of the business community. This Board is responsible for overseeing and monitoring all significant aspects and the business affairs of the Corporation and its affiliates. This responsibility includes appointing the 6 members to the Board of Directors of Essex Powerlines Corporation. Board appointments are for 4 year terms and are made in offsetting 2 year timeframes between the parent corporation Board and the Boards of the affiliates.

The Board of Directors of Essex Powerlines Corporation is comprised of 6 members, appointed by the parent corporation Board as noted above. These appointments include 2 of the elected municipal representatives of the parent corporation Board, 2 of the non-elected members of the business community from the parent corporation Board, and 2 fully independent Directors that are not members of the parent corporation Board.

1.3.15 List of Specific Approvals Requested

- Approval of the 2025 Test Year rate base as proposed in Exhibit 2 – Rate Base
- Approval of EPLC's average net book value of fixed assets and working capital allowance as proposed in Exhibit 2 – Rate Base
- Approval of the 2025 Test Year revenue requirement as proposed in Exhibit 6 – Calculation of Revenue Deficiency or Sufficiency
- Approval of the capital structure, cost of capital parameters, and deemed return on equity and debt proposed in Exhibit 5 – Cost of Capital and Capital Structure
- Approval of the Test Year Operations, Maintenance and Administration expenses, property taxes and payments in lieu of taxes (PILs) in Exhibit 4 – Operating Expenses
- Approval of the 2025 Test Year Revenue Requirement of $19,494,342, as proposed in Exhibit 6 – Calculation of Revenue Deficiency or Sufficiency
- Approval of the 2025 Test Year Base Revenue Requirement of $18,388,098, as proposed in Exhibit 6 – Calculation of Revenue Deficiency or Sufficiency
- Approval of the 2025 Revenue Offsets of $1,106,244, as proposed in Exhibit 3 – Operating Revenue
- Approval of Cost Allocation as filed in Exhibit 7 – Cost Allocation
- Approval of 2025 distribution rates and charges, effective January 1, 2025, as proposed in Attachment 8-C - Proposed Tariff of Rates and Charges of Exhibit 8 – Rate Design
- Approval of the 2025 Load Forecast as documented in Exhibit 3 – Customer and Load Forecast
- Approval of a revised loss factor as identified in section 8.14 of Exhibit 8 – Rate Design
- Approval of updated Retail Transmission Service Rates (RTSRs), as identified in Section 8.3 of Exhibit 8 – Rate Design

- Approvals for the clearance related to the December 31, 2023 audited balances of ($7,268) for Group 1 DVA accounts, and associated class specific rate riders and manual adjustments effective January 1, 2025 as set out in Exhibit 9 – Deferral and Variance Accounts
- Approvals for the clearance related to December 31, 2024 forecast balances of ($1,969,222) for Group 2 DVA accounts, and associated class specific rate riders and manual adjustments effective January 1, 2025 as set out in Exhibit 9 – Deferral and Variance Accounts
- Approval for a Z-Factor claim and associated class specific rate riders as set out in Exhibit 8 – Rate Design

1.4 Distribution System Overview

1.4.1 Overview

EPLC services the four non-contiguous areas of its shareholder municipalities; The Town of Amherstburg, the Town of LaSalle, the Town of Tecumseh, and the Municipality of Leamington. EPLC services only portions of Amherstburg, Leamington and Tecumseh while it services the entire Town of LaSalle. EPLC's service territory is formally defined in Schedule 1 of its OEB approved Distribution License (ED-2002-0499) as:

1. The Town of LaSalle as of June 1, 1991;
2. The Town of Amherstburg as of December 31, 1997;
3. The Town of Tecumseh and the Village of St. Clair Beach as of December 31, 1998;
4. The Town of Leamington as of December 31, 1998;

A map of EPLC's Service Area is provided in Figure 1-3.

Figure 1-3: Map of Essex Powerlines Service Area

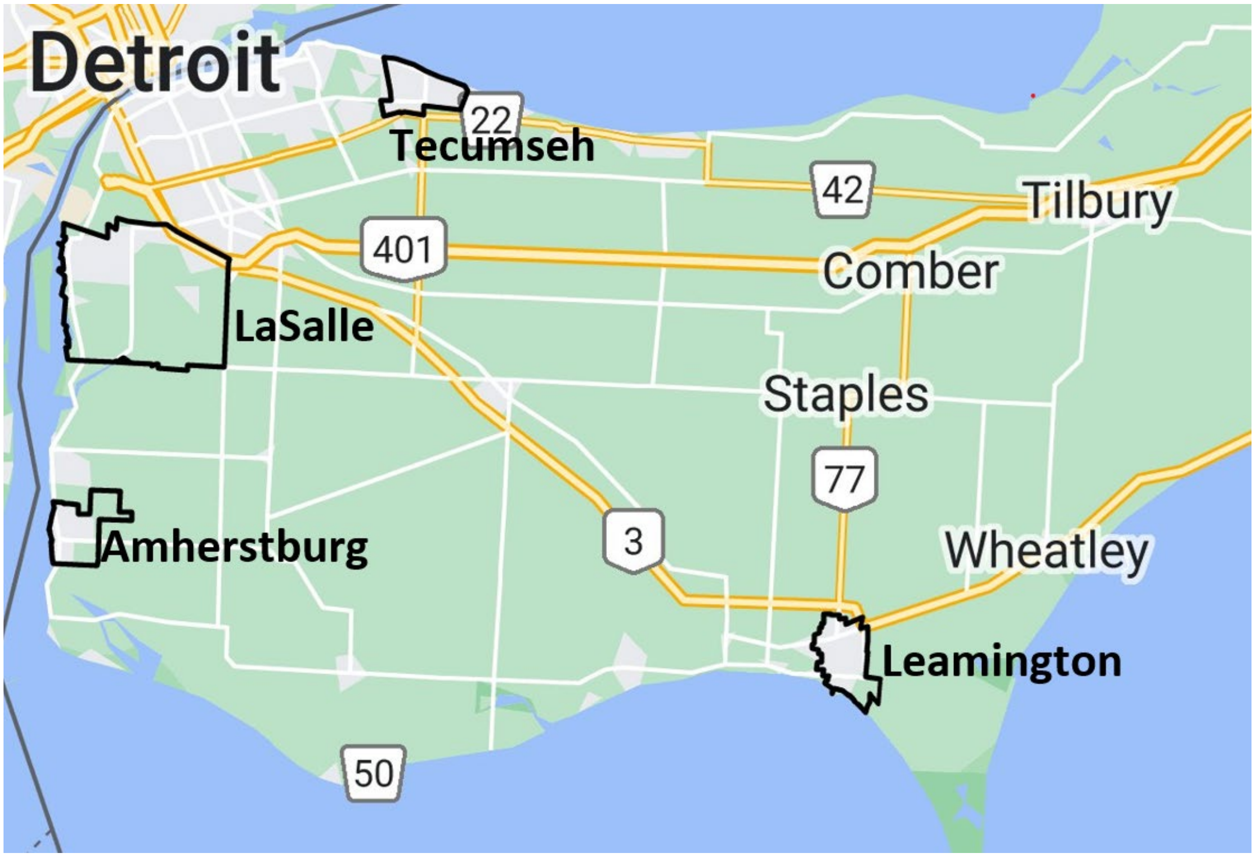


Table 1-15: Breakdown of EPLC's Service Area

Communities Served	Town of Amherstburg; Town of LaSalle; Town of Tecumseh; Municipality of Leamington
Customer Count & Connections	34,362
Business and Residential Customers	28,912
General Service Customers <50kW	2,062
General Service Customers 50 to 4999kW	230
Embedded Distributor	4
Overhead Lines	180.5km
Underground Lines	281.3km
Number of Poles	6251
Voltage Levels	27.6kV

Note: Information based on 2023 Actuals.

Essex Powerlines' neighbouring electricity distribution utilities are:

- ELK Energy

- ENWIN Utilities Ltd.
- Hydro One Networks Inc.

Hydro One Networks Inc. borders all four of EPLC's service territories and is embedded in EPLC's service territories within the Town of Amherstburg. ENWIN Utilities Ltd. borders both Tecumseh to the west and LaSalle to the north.

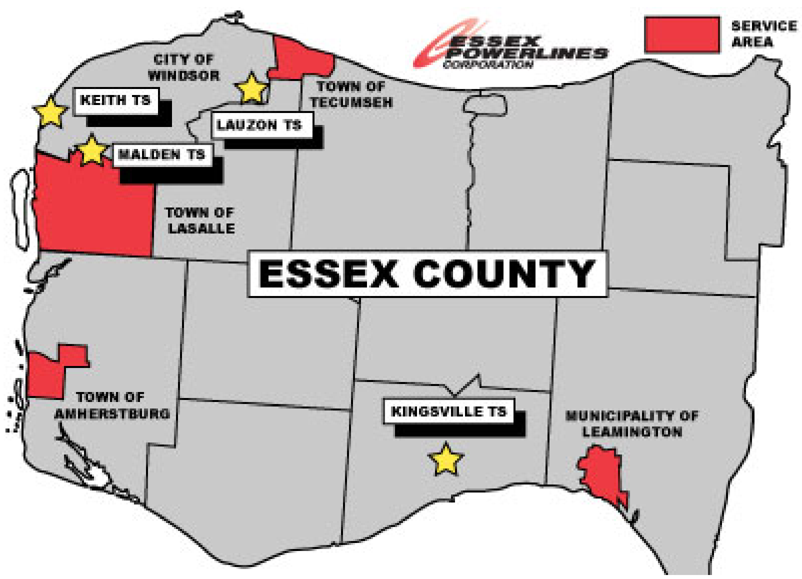
1.4.2 Identification of Embedded or Host Distributor

EPLC is wholly embedded in Hydro One Networks Inc's ("HONI") distribution system. EPLC is fed from four separate HONI transformer stations at 27.6 kV:

i) Keith TS (Services portions of LaSalle & Amherstburg);
ii) Leamington TS (Services Leamington);
iii) Lauzon TS (Services Tecumseh);
iv) Malden TS (Services portions of LaSalle & Amherstburg);

Figure 1-4 below shows the geographic location of each transformer station.

Figure 1-4: Geographic Location of Transformer Stations



1.4.3 Transmission or High Voltage Assets

Essex Powerlines Corporation does not have any transmission or high voltage asset (>50kV) deemed previously by the Board as distribution assets and does not have any such assets for which Essex Powerlines Corporation is seeking OEB approval to be deemed as distribution assets in this Application.

1.4.4 Business and Industry Review

The energy landscape has evolved significantly over the past decade and continues to evolve at a rapid pace. Utilities across the globe are shifting towards a smarter, more resilient, and sustainable grid, and Ontario utilities do not fall short of this mandate. Significant change has occurred, challenging the ways local distribution companies currently operate and impacting the costs associated with these traditional operations. Local distribution companies need to grow and evolve to keep pace with the changing landscape of the industry and to ensure federal, provincial, and municipal mandates and targets are being met. As such, the evolution of the sector has, and will continue to have, significant impacts on distribution system operations. This section highlights some of the factors that have impacted Essex Powerlines.

Regulatory and Policy Changes

The regulatory landscape has evolved significantly in the last decade, with an increase in regulatory and public policy initiatives that utilities are mandated to follow and report on. Essex Powerlines has maintained compliance with the increasing regulatory landscape, however, at a cost to its employees and customers. With the expectation that local distribution companies must evolve their operations to meet the demands of the changing electricity landscape, they are also encumbered with ensuring compliance is met for the growing regulatory needs, while at the same time ensuring better and increased engagement with customers. Employees have increased pressure to maintain existing duties while conforming to new mandates in a short period of time. Below are some of the mandated programs that have been introduced since EPLC's 2018 COS, some of which have put upward pressure on costs:

- Implementation of the OEB Cyber Security Framework (2018)
- Increased reporting for Activity and Program-based Benchmarking Initiative (2019)
- The cancellation and centralization of Conservation and Demand Management (2019 & 2020)
- Implementation of the Ontario Rebate for Electricity Consumers Act ("OREC") (2019)
- Implementation of changes to Customer Service Rules (2019 & 2020)
- Continued connection of Renewable Generation
- Implementation of the OEB's standardized accounting process for RPP settlement (2019)
- Elimination of the Collection of Account Charge (2019)
- Installation of Metering Inside the Settlement Timeframe (MIST) meters for GS>50kW customers (2020)
- Implementation of COVID-19 Billing Changes (2020)
- Implementation of Time-of-Use Opt-Out and Tiered Billing (2020)
- Implementation of Ultra Low Pricing (2023)
- Implementation of Green Button (2023)

Resources to address regulatory demands and processes continue to be a concern for Essex Powerlines. EPLC has experienced significant turnover in regulatory roles, and jobs remain unfilled due to the inability to find and recruit qualified individuals.

Workforce and Job Market Changes

The utility sector has an impending obstacle as it relates to the current aging workforce and prospective job market, and EPLC's existing labour force is no exception. The utility sector across Ontario will see many of its employees becoming eligible for retirement in a relatively short timeframe, and as such, succession planning is key for knowledge transfer and dissemination of current operations.

Historically, jobs in the utility industry have been difficult to fill due to the institutional knowledge needed to navigate such a niche market. Onboarding new employees takes several months to years to reach optimal knowledge retention. Essex Powerlines has been prescient to identifying positions with highest priority for succession planning but has had challenges in recruiting talent to its workforce, as competition for trades, engineering, regulatory, and experienced executive management has been historically high. Retaining and recruiting utility skills continues to be a major challenge in this market.

In the past year, EPLC has experienced significant turnover in its regulatory, engineering, and operations roles. While some jobs remain unfilled due to the inability to find and recruit qualified individuals, others have been filled but are currently undergoing the vigorous training needed to combat the large learning curve that is typical to the industry. When reviewing the ratio of metered customers to full time employees from EPLC's previous Cost-of-Service year in 2018 and comparing it to 2022, the ratio has significantly increased from 654 customers-per-employee to 734. This is primarily due to the growth of EPLC's customer base, as well as the reduced number of FTEs.

Moreover, with the changing landscape of the utility industry, EPLC will face even more challenges with recruiting new talent to fill the gaps between operating as a traditional local distribution company and transforming into a distribution system operator (DSO). More resources will be needed to mitigate constraints and burnout of existing employees and to successfully evolve with the market and occupy new market roles such as operating as a DSO.

As such, Essex Powerlines is making every effort to build up its existing workforce by attracting and retaining top talent, continuing to develop succession planning for critical/priority positions, and continuing to work on individual employee development plans for specific positions within the organization.

Customer Preferences and Expectations

Customers are becoming increasingly aware and knowledgeable of the electricity system and as such, are transitioning from a traditional consumer to an energy prosumer, where they are becoming active participants in the grid through both the consumption and supply of electricity. To enable consumer choice through electrification and conservation efforts, LDCs must evolve their current operations and implement new structures that enable the integration of increased DERs in a way that maximizes value to the ratepayer, while also maintaining reliability and safety.

LDCs are aware of the electricity transition that needs to occur to support the future of the grid, and as such, need to continue to emphasize their interactions with consumers by informing and engaging with them to ensure needs are being met and understood. As the lowest common denominator and direct point of contact with customers, LDCs must be able to respond to their demands by offering more innovative and customer-centric solutions. As such, Essex Powerlines will continue to deliver value to its customers, shareholders, and society by providing high-quality, low-cost, and reliable electricity, and by engaging with its customers to ensure maximum value is being achieved.

Technological Advancement and Cyber Security

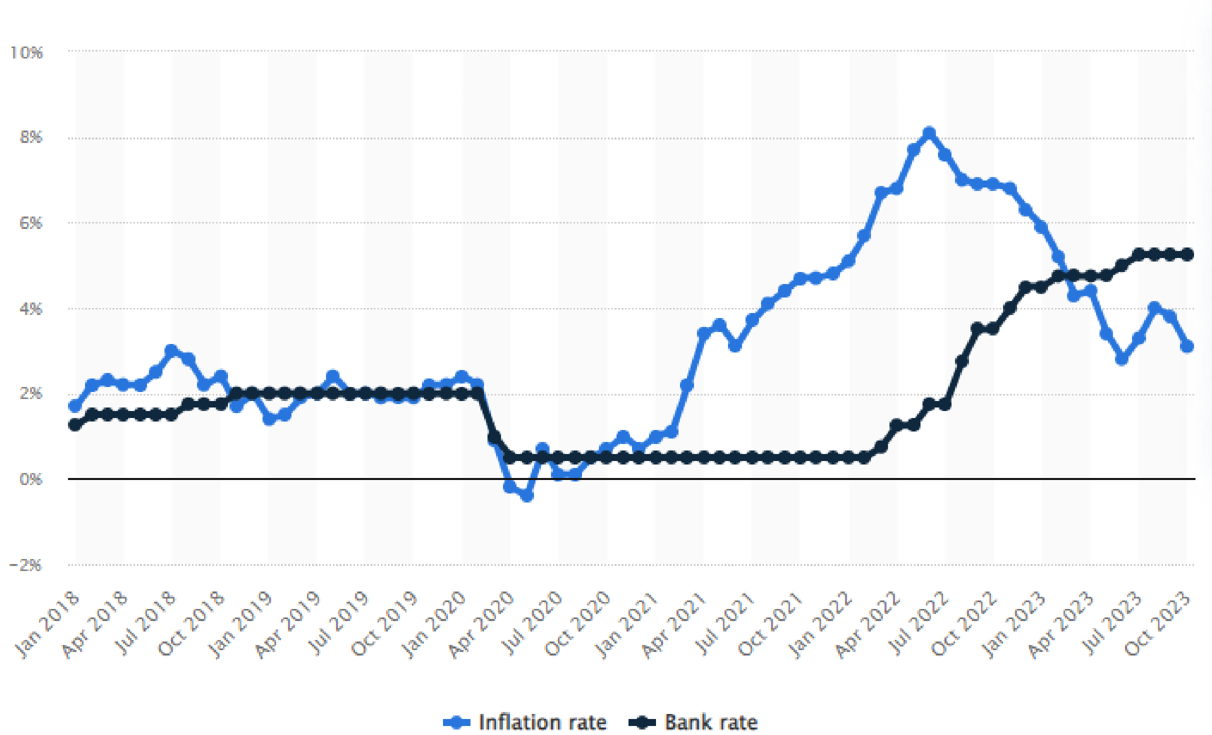
Utilities are at the forefront of technological advancement, with new technologies being integrated into the grid, as well as used in the back-office to create efficiencies within the operations of the utility. Advancements in technology within the grid that EPLC has been exposed to include, but are not limited to, the integration of distributed energy resources, battery energy storage systems, market trading platforms, and microgrid solutions, among others. These new technologies are important and necessary for the advancement of the grid and to meet the growing needs of consumers.

With the implementation of new and innovative technologies, utilities have become susceptible to cyberattacks, and as their technology portfolio grows, they will become more exposed to cyber threats. Essex Powerlines has been proactively addressing vulnerabilities within the organization by integrating cybersecurity measures into its practices, over and beyond the implementation of the OEB Cybersecurity Framework. As Essex Powerlines continues its roadmap to a more comprehensive and digitized utility, they are cognizant of the fact that they will become subjected to more frequent cybersecurity threats. EPLC will continue to take a multi-faceted approach to its cyber security practices by investing in advanced cyber security technologies, continuing to adapt and evolve its cybersecurity protocols, and implementing best-practice solutions to mitigate cyber security risk.

Global Inflation

Canada’s annual inflation rate in 2023 was 3.1%, down from 6.9% in 2022, the highest level seen since 1991. The graph below indicates the average inflation rate and bank rate in Canada from January 2018 to October 2023.

Figure 1-5: Canada's Annual Inflation Rate



Source: https://www.statista.com/statistics/1312251/canada-inflation-rate-bank-rate-monthly/

These inflationary increases over the last few years have caused significant cost increases on materials, goods, and services related to Essex Powerlines' capital and operating costs. Some examples of costs that have gone up in the last couple of years include, but are not limited to:

- 66% increase in the price of diesel fuel and 37% increase in gasoline fuel costs.
- 47% average increase in costs for transformers
- 67% average increase in costs for wood poles
- 85% average increase in costs for wire and cable

EPLC continues to navigate through the operational changes that have occurred due to inflation and seek areas of improvement to maintain affordable rates for customers, without compromising the safety and reliability of the distribution system.

COVID-19 Pandemic

The COVID-19 pandemic has caused significant increases in costs due to major supply chain disruptions. EPLC, alongside other utilities in Ontario, are facing pressure on ongoing supply costs and significant delays in the delivery of materials. This has greatly impacted timelines for completing some projects, and while the availability of materials and distribution system equipment is now beginning to alleviate, costs remain high. EPLC continues to manage customer relations as it relates to supply chain delays and is finding ways to mitigate the impact of COVID-19 on its day-to-day activities.

Adverse Weather Events

The energy industry has been facing increasing challenges to protect its distribution system from an increase in adverse weather events. As the climate changes, the frequency and intensity of weather events has become increasingly prevalent, threatening critical utility infrastructure, and making utilities vulnerable to reliability pressures. In addition, utilities are experiencing additional operational and reactive maintenance costs to restore power and reverse damage to its distribution system.

Understanding that these storms and adverse events are becoming more frequent, EPLC plans to invest in technology and tools that will help improve system reliability and resiliency. In addition, EPLC has focused on creating its Asset Condition Assessment Plan and Asset Replacement Plan to improve asset health and ensure system hardening. By having a proactive asset management plan, EPLC hopes to mitigate future costs related to adverse weather events.

Electrification of Transportation

The electrification of transportation in Canada will be profound for utilities, as they will play a pivotal role in the future of the transportation landscape. According to the IESO Planning Outlook Report[6], the overall electricity demand from transportation electrification is forecast to grow from about 2 TWh in 2025 to 44 TWh in 2050, an average annual growth rate of 12.8 percent. This is in part, due to the Government of Canada's announcement of achieving 100% zero-emission vehicle sales by 2035 for all new light-duty vehicles.

The transition to electrification poses many obstacles for utilities, including lack of visibility into current and future EV growth forecasts to ensure proper planning and opportunities for grid management and integration. EPLC has been proactive in its management of the transition by investing in and developing technologies, such as its DER & EV Visibility Tool embedded in SmartMAP, that uses detection algorithms to determine households that have existing EVs. In addition, EPLC has been successful in obtaining Natural Resources Canada funding through its Zero-Emission Vehicle Infrastructure Program, to act as a delivery organization to distribute funding to organizations who would like to install charging infrastructure in public places, on-street, in multi-unit residential buildings, at workplaces, or for light-duty vehicle fleets. To date, 451 EV charging stations have been, or are planned to be, installed within the Windsor-Essex Region.

While the above-mentioned initiatives are just steppingstones in the greater scheme of electrification of transportation, EPLC believes that larger steps need to be taken to support the tsunami of EVs that will

[6] IESO Planning Outlook Report, https://ieso.ca/Sector-Participants/Planning-and-Forecasting/Annual-Planning-Outlook, p. 24

penetrate the region (and Ontario). A combination of investments in smart grid technologies, non-wires alternatives, and technology to retrieve real-time utility data and load forecasting at the distribution level are all necessary and imperative for a successful electrification transition. EPLC believes that through collaboration efforts with municipalities, regional government, shareholders, the IESO, and the OEB, a fully integrated, modern, and innovative model could be developed for the utility of the future. This model would provide renewable and smart energy solutions to residential and commercial customers, utilizing advanced technologies, such as smart meters, microgrids, and blockchain to optimize the distribution and consumption of electricity.

Greenhouse Development, Manufacturing and Agriculture Landscape

According to the Windsor-Essex Regional Planning and Integrated Regional Resource Plan developed by the IESO, electricity demand in the Windsor-Essex Region, particularly in Kingsville-Leamington, is growing rapidly due to agriculture and manufacturing development. Electricity demand in Windsor-Essex and Chatham-Kent alone are forecast to grow from roughly 500MW of peak demand today to about 2,100 MW in 2035, almost the equivalent of adding a city the size of Ottawa to the grid. As such, the provincial government has announced the timely development of new electricity transmission infrastructure projects in the region to help alleviate some of the expected constraints, however, does not solve all the constraints that will emerge through the continued growth of both the indoor agriculture and manufacturing industry.

The greenhouse and agriculture industry have no signs of slowing down, as the existing geographic area is preferred due to the local industry expertise, access to labour, access to both Canadian and U.S. markets, and the availability of supporting services and infrastructure in nearby towns.

"Ontario's power system is operating within a period of tighter supply conditions" [7] according to the IESO's December 2023 18-Month Reliability Outlook Report, and these tight supply conditions are paired with pronounced forecasted capacity constraints in southwest of the province.

The total locational capacity requirement West of London grows to 1,975 MW by 2035, 550 MW of which is in the Windsor-Essex and Chatham-Kent areas closer to the greenhouse loads (i.e., West of Chatham).[8] Forecasted growth in Windsor-Essex and Chatham Kent is significant and expected to exceed existing transmission system capacity such that the "Leamington T1/T2 and T3/T4 DESNs [are] expected to be loaded above their long-term emergency ratings during the 10-year forecast period on both summer and winter".[9] [10] [11] In addition, the government recognized the importance of this need by issuing an Order in

[7] IESO, Reliability Outlook January 2024 to June 2025, published December 2023, page 31
[8] IESO, 2022 Annual Planning Outlook, published December 2022, page 69
[9] IESO, Windsor-Essex Region Scoping Assessment Outcome Report, published May 2023, page 9
[10] Ministry of Energy, Powering Ontario's Growth, published July 2023, page 42
[11] IESO, Reliability Outlook January 2024 to June 2025, page 28

Council in April 2022 declaring the three transmission line projects recommended in the regional and bulk plans as priorities.[12] [13]

To be more certain in the materiality of the region's need, agricultural growth continues past 2035 as the total sector is "forecasted to grow from 5 TWh in 2024 to 8 TWh in 2043"[14] "primarily in the Kingsville-Leamington and Dresden areas".[15]

While new transmission infrastructure systems will be important in mitigating some of the constraints that Southwestern Ontario is expected to experience, it comes at a large cost to ratepayers and still leaves gaps for more permanent solutions to the lack of supply issue at hand. EPLC is cognizant of the demand and supply concerns in the area and continues to closely monitor the situation. Moreover, EPLC is investigating innovative solutions to help mitigate grid constraints while also minimizing the need for large build-out costs through its PowerShare project. PowerShare explores the opportunity of operating as a Distribution System Operator and creating local energy markets that allow for customers with existing DERs to participate. Utilizing existing capacity (as non-wires solutions) within the distribution system to alleviate constraints has many benefits, including allowing customers to maximize the value and monetize their DER assets, avoiding large build-out costs that would get passed down to ratepayers, and creating more visibility and control within the grid for local distribution companies and the IESO alike. Details regarding PowerShare can be found in EPLC's DSP attached to Exhibit 2, section 5.4.1.

LDCs need to be creative in their approach to accommodate expected load growth in coming years, whether it is due to increased electrification or growth in the agriculture and manufacturing industries. With the support from the greenhouse industry, EPLC is developing a plan for increased investment in regulated assets and is looking forward to exploring new opportunities and methods to resolve grid constraints, while also being attentive to municipal, provincial, and federal mandates.

1.5 Customer Engagement

1.5.1 Introduction

The RRFE strongly encourages distributor interaction and engagement of their customers in an effort to better align the strategic goals of the distributor with the customer needs. In its day-to-day business, EPLC currently engages its customers in a variety of ways including:

[12] Ministry of Energy, News Release published April 2022, "Ontario Supporting Economic Growth in Southwest Ontario"
[13] IESO, Windsor-Essex Region Scoping Assessment Outcome Report, published May 2023, page 7
[14] IESO, 2022 Annual Planning Outlook, published December 2022, page 22
[15] IESO, 2022 Annual Planning Outlook, published December 2022, page 21

- Website/Social Media Updates;
- Email Campaigns and Newsletters;
- Bill Inserts & Flyers;
- Telephone Interactions (Inbound/Outbound);
- Online Portal;

In order to support this Application and in the spirit of the RRFE, EPLC conducted incremental customer engagement outlined in Section 1.5 of this Exhibit, as well as in Attachment 1-H. EPLC customers from all classes were considered and were overall satisfied with EPLC's level of service. More specifically, EPLC reached out to customers through a detailed survey that confirmed ongoing feedback regarding customers' needs and demands. The survey highlighted customers prioritized reliability, and as such, EPLC used this feedback as an input to its plans in the DSP and to continue to invest in tools and equipment that will ensure reliability standards are met and any customer concerns are mitigated.

1.5.2 Ongoing Customer Engagement

Essex Powerlines' customer base is growing, and their demands are changing, and as such, it is imperative to listen to and understand customers' needs and priorities to continue to meet and exceed their expectations. EPLC's approach to customer engagement takes into consideration that:

- Customers are becoming increasingly aware and knowledgeable on utility practices, conservation and demand management, electrification, etc.
- With information at their fingertips, EPLC sees an opportunity to grow and expand with its customers to ensure accurate data and information is available for them to make informed decisions on their electricity usage.

EPLC's focus is providing safe and reliable power to its customers at an affordable rate. Customers need to continue to feel valued and supported during the information technology transition. According to a 2021 McKinsey & Company report, consumers expect personalization from businesses they interact with,[16] and as such, EPLC continues to offer an enhanced, customer-centric experience to its customers, with increased engagement. This is achieved by leveraging the following approaches:

- Automating systems, providing new technologies to augment the customer experience, and implementing and facilitating process innovations.
- Ongoing customer focused solutions and investments including but not limited to, new phone system, new Essex Powerlines website that is more user-friendly, new online chat bot with 24/7 access, customer portal, outage center, outage push notifications to social media accounts (Twitter), Green Button integration.

[16] *Next in Personalization 2021 Report*. McKinsey & Company, https://www.mckinsey.com/capabilities/growth-marketing-and-sales/our-insights/the-value-of-getting-personalization-right-or-wrong-is-multiplying, 2021.

- Planned future improvements - new customer app, push notifications to phone for outage information and energy savings tips, enabling customer DERs through DSO.
- Informing and educating customers on the business of the utility through an omni-channel approach (website, social media posts, press release services, e-mail campaigns, bill inserts, phone calls, letters, etc.)
- Conducting customer surveys to understand customer perspectives and receive valuable feedback. This feedback informs the activities at EPLC.

Digital approaches continue to serve a valuable role in EPLC's approach to customer engagement. Specifically, social media channels such as Facebook, Twitter, and LinkedIn are leveraged to communicate varied and relevant information to EPLC's customers. The following sections outline the different channels EPLC uses to communicate with its customers.

Social Media

Essex Powerlines Corporation uses Facebook, Twitter, and LinkedIn to communicate with its customers on an ongoing basis. Social media strategies are developed by the Communications Department and consist of campaigns covering a broad range of topics and initiatives, such as safety campaigns, outage campaigns, energy savings campaigns, and educational campaigns, among others. These campaigns are planned and scheduled through a tool called Hootsuite. Hootsuite is a social media manager that tracks trends and themes to help understand what type of messaging resonates with customers and to also help improve social media performance metrics. EPLC uses the analytics reports pulled from Hootsuite to tailor messaging specific to its customer base and ensure an appropriate engagement rate is met.

EPLC utilizes each of its social media platforms to reach different customer groups and the public at large through various tailored messaging. For instance, Twitter is used to share media releases and news surrounding Essex Powerlines' municipal shareholders. Twitter's main function for Essex Powerlines includes outage notifications to its customer base. EPLC has an automated tool that signals when an outage has occurred and pushes a notification to both its website and its Twitter account. The outage message posted to Twitter includes details such as whether the outage was planned or unplanned, how many customers were affected, the estimated time of restoration, and a link to EPLC's Outage Centre on its website. The message also tags the municipality that the outage is occurring in, so that the municipalities' communications team is informed of the outage and can easily share the message to their social media pages as well.

LinkedIn is a tool that Essex Powerlines continues to use for growing and developing its workforce, sharing job postings, and sharing other relevant industry-related news. Essex Powerlines also uses LinkedIn to garner the attention and feedback of other industry professionals on strategic projects that are ongoing within the organization. Since inception in 2022, EPLC has seen a 301% increase in followers.

Essex Powerlines' Facebook account is primarily used for social campaigns, such as community giveback initiatives, safety campaigns, outage campaigns, and customer feedback initiatives. EPLC's

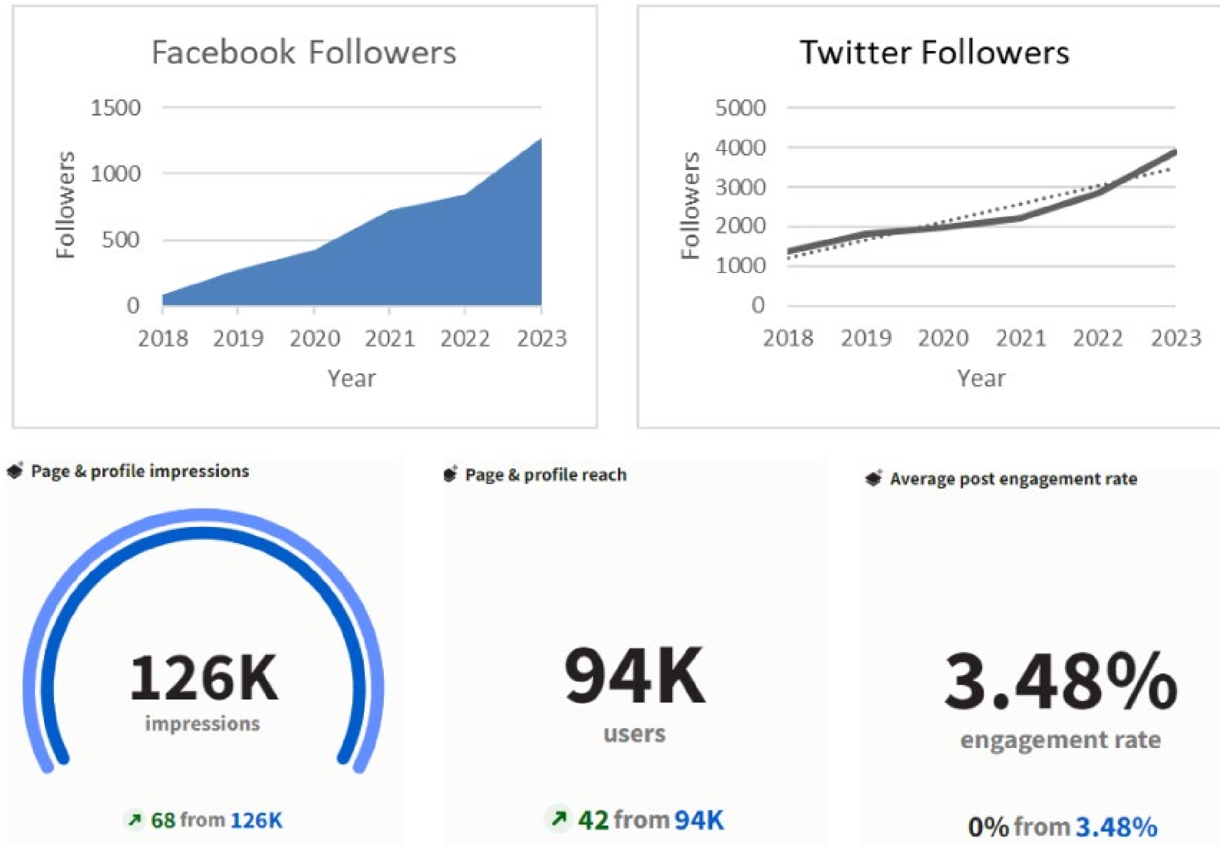
Communications Department monitors all its social media channels and replies to online customer inquiries in a timely manner.

While social media channels were not used to directly reach out to customers regarding the cost-of-service application, EPLC does monitor its social channels for customer feedback and reviews that may influence future spending and investments. For instance, EPLC's communication team reviews and monitors each of its respective shareholder municipalities' community groups on Facebook to see whether EPLC has been mentioned and if response is required. Most often, customers have taken to social media on issues surrounding reliability of services during power outages due to adverse weather events and animal interference. This feedback is in parallel with the major concerns brought up in the Customer Engagement Survey, which is discussed in further sections below. EPLC used this information to help inform its DSP and ensure appropriate spending is allocated to increase and maintain reliability metrics and mitigate increased outages.

Facebook & Twitter Analytics

Facebook and Twitter had a cumulative engagement rate of 3.48% and over 126,000 impressions from January 2023 to December 2023. According to Hootsuite, a good engagement rate is between 1 to 5%. Facebook followers have steadily increased since EPLC first joined, with a 50% year-over-year increase from 2022 to 2023. Likewise, Twitter followers have steadily increased, with a total of 3,899 followers in 2023 (37% increase from 2022).

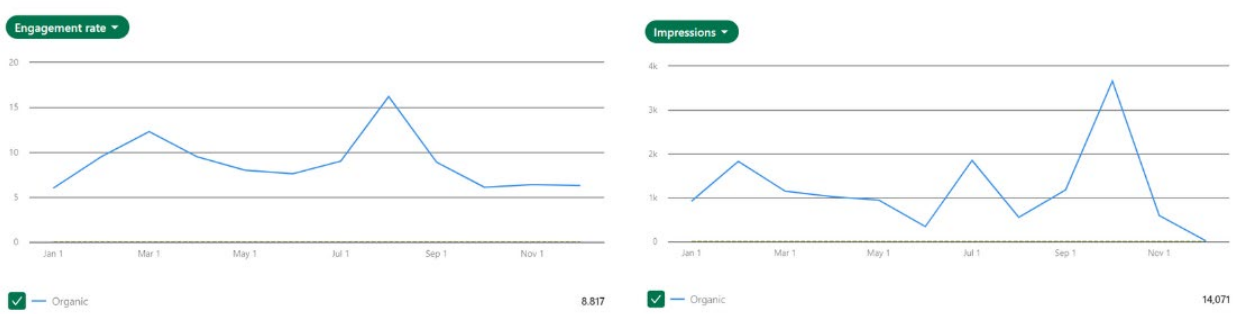
Figure 1-6: Social Media Analytics



LinkedIn Analytics

EPLC's LinkedIn had an engagement rate of 8.8% and 14,071 organic impressions. LinkedIn remains a top platform for sharing indsutry-related news, EPLC's special projects, and job postings.

Figure 1-7: Social Media Analytics



Email Campaigns

Essex Powerlines engages with customers who opt-in for email communications with targeted campaigns through a platform called MailChimp. MailChimp is an email marketing platform that allows you to personalize, design, and send email campaigns to customers. The platform also includes optimization tools and data analytics to see the success rate and impressions of each email that is sent. Campaigns target specific customer audiences such as residential and commercial/industrial customers. An example of email communications sent to a specific customer base is when Essex Powerlines has new customers move in its service territory. A welcome email will go out to new customers with some high-level information on how to retrieve bills, how to sign up for MyAccount, where to find pertinent information about EPLC, and more. Essex Powerlines now has email addresses for over 45% of its customer base and has strategies in place to retrieve more emails in the coming years.

Specific to the Cost of Service, EPLC used a third-party, Innovative Research Group, to reach its customer base via email marketing campaigns to fill out a Rate Application Survey. The email campaign was extremely successful, with 1,874 residential customers and 21 small business customers completing the survey. The survey responses are much more significant than previous surveys where the main communication method was via telephone survey (typical telephone surveys for EPLC would see approximately 400 customer responses in total). The email campaigns are a significant tool for reaching customers and sharing pertinent information. EPLC plans to continue using email campaigns to share relevant information, including on future surveys and rate applications.

Essex Powerlines' Website

Essex Powerlines' website remains the digital storefront of the organization. In 2021, EPLC completed a website refresh, making the website more accessible and user-friendly for its customers. Enhancements to the website included an Outage Centre, mobile optimization, updated content, and more seamless contact forms. The Outage Centre includes an outage map that automatically updates every 15 minutes to visually show where an outage has occurred in EPLC's service territory. In addition, the Outage Centre contains outage history "tiles" that are colour-coded based on planned, unplanned, or restored outages. Lastly, the Outage Centre includes a simplified reporting form that customers may use if an outage has occurred and hasn't been processed on the website yet. In late 2022, Essex Powerlines also implemented a 24/7 Chatbot on its website that directly links a customer to a Customer Service Representative. The Chatbot is used to assist customers with information pertaining to outages, account information, moving in or out of the service territory, electricity rates, or help with other customer inquiries.

Essex Powerlines will use its website to notice of its Cost-of-Service Application as directed, as well as any proposed changes that may uniquely affect rate classes.

Press Releases

Essex Powerlines actively engages in writing press releases to be shared with local and provincial news outlets. Essex Powerlines has a good working relationship with its local news outlets and can often get critical information out to targeted audiences through press releases in a timely manner. Typical information sent through a press release includes large in-field maintenance updates, innovative projects, programs available to consumers, and social/community initiatives.

Radio Ads

EPLC will often use radio ads to engage customers in safety campaigns and paperless billing initiatives. In addition, radio shows will be used when major events occur in EPLC's service territory to ensure a larger audience is reached.

Bill Inserts

Moreover, Essex Powerlines utilizes bill inserts to share pertinent regulatory information, such as rate application submissions and approvals, and Time of Use or Tiered Rate changes. EPLC also sends bill inserts to customers to promote social campaigns, paperless billing initiatives, and new customer care features (chat bot, website, etc.).

Municipal Shareholders

Essex Powerlines meets with its municipal shareholders (the Town of Amherstburg, the Town of LaSalle, the Town of Tecumseh, and the Municipality of Leamington) to review planning and development information. These meetings help inform EPLC's distribution system planning and inputs from the meeting are considered in the DSP.

Community Outreach

Essex Powerlines is built on the foundation of the communities it serves, and as such, community outreach is integral to EPLC's corporate philosophy. Each year, Essex Powerlines gives back to its communities through various events and programs, including but not limited to, investing in youth and education programs, school electrical safety programs, donating to local charities through paperless billing campaigns, supporting local food banks during peak holiday season, and volunteering time and resources at various local events.

Most recently in 2023, Essex Powerlines:

- Invested in its "Youth in Community Fund" for the 10th consecutive year. The fund provides $10,000 to each of EPLC's Shareholders to be used towards youth-oriented programming and initiatives, such as the Essex EmPOWERment Girls Group, Youth Advisory Committees, Summer Concert Series, and Earth Day celebrations, to name a few.

- Sponsored and supported various Build a Dream events. Build a Dream is a national non-profit organization that supports and empowers young women to explore careers in skilled trades and STEM (science, technology, engineering, and mathematics).
- Partnered with Erie Shores Healthcare hospital in the Municipality of Leamington to sponsor their Lights of Life Event. EPLC employees volunteered their time and effort to hang Holiday lights.
- Donated over $1000 to the Fight Like Mason Foundation, which is a local registered charity organization created by parents of Mason Bacon-Macri, who died of Rhabdomyosarcoma at the age of four.
- Adopted families within its Shareholder communities in support of the Adopt a Family Program at the Windsor-Essex Children's Aid Society. Gifts of cash, toys, and personal hygiene products were donated by employees to help support families during the holiday season.
- Participated in Fire Safety Week with local fire departments to communicate electrical safety tips to customers.

These initiatives are just some small examples of how Essex Powerlines supports its local communities and demonstrates pride in representing and participating in local initiatives. EPLC plans to continue to support its Shareholder communities through continued youth and education programs and various giveback initiatives.

Phone Calls

Essex Powerlines received over 38,000 customer phone calls in 2023, with over 84% of those being answered within 30 seconds. EPLC is proud of its success in answering customer requests and handling complaints in a professional and timely manner, demonstrating its commitment to its customers.

Other Ongoing Communications

EPLC engages and meets with customers through coordinated planning and initiatives. Consultations could be for subdivision development, preparation of job sites, or simply to understand the needs of commercial customers. Typically, these types of engagements occur using an omni-channel approach (including in-person visits, site visits, email, and telephone calls), depending on the nature of the project. Essex Powerlines maintains open communication with its developer customers and commercial customers to foster trust and ensure plans are being met accordingly.

1.5.3 Application-Specific Customer Engagement

EPLC holds regular customer engagement surveys to help understand customer needs and satisfaction with existing services. Feedback received from customer surveys is used to influence EPLC's priorities moving forward and is incorporated in distribution system planning efforts. The surveys also provide opportunities for education and awareness regarding EPLC's operations, improvements to service, and strategic initiatives.

Customer Satisfaction Survey - Innovative Research Group

In 2021 and 2023, EPLC conducted its bi-annual Customer Satisfaction Survey with Innovative Research Group. The Customer Satisfaction Survey helps EPLC understand how it is performing in the eyes of its customers and prompts EPLC to make adjustments in areas where the organization is underperforming. The objective of the survey is to canvass customer satisfaction in five key areas: power quality and reliability, price, billing and payment, communications, and customer service experience.

The 2023 Customer Satisfaction Survey was conducted from June 12, 2023, until June 26, 2023, via one-on-one telephone interviews. 413 customers from a random sample were selected to participate, representing 90% residential and 10% general service (under 50kW) customers. The sample size was weighted down to 400 to ensure proportional representation based on rate class, annual electricity consumption, and region (Amherstburg, LaSalle, Leamington, and Tecumseh).

Over the past couple of surveys, Essex Powerlines has maintained a high overall informed CSAT score, with the latest overall score being 87%. This sheds light on EPLC's operations of providing reliable power to its customers at an affordable rate and continuing to support its customers through various communications and enhancing the consumer experience. Below outlines some of the outcomes from the most recent Customer Satisfaction Survey:

- Customers ranked their familiarity with EPLC and its operations as 73% overall, with a 79% overall satisfaction rate.
- 3-in-4 customers are satisfied with the restoration times of power outages. While this is still a relatively good scoring, EPLC sees this as an opportunity to improve reliability for its customers.
- Power quality increased from previous years, with an overall satisfaction rating of 79%.
- 90% of EPLC customers are satisfied with the options to receive and pay their EPLC bills.
- Overall satisfaction with customer service remained stable in comparison to previous years. EPLC sees this as an opportunity to invest in enhancing the consumer experience.
- Satisfaction with communications remained steady over the years, with a rating of 67% (higher among GS customers). EPLC sees its communication efforts with residential customers as an area of opportunity.
- 1-in-5 (21%) of customers expressed that they would like EPLC to improve reliability and time to restore power.

Results from the survey were used to inform EPLC's planning for the 2025-2029 forecast period. Customers' main focus was on reliability and time to restore power. EPLC has taken this into consideration and is making appropriate investments in its distribution system to address the reliability concerns of customers. These investments include, but are not limited to, investing in reclosers, and enhancing control room operations, updating technology in the field, and investing in fleet management to improve time to restore power.

Public Awareness of Electrical Safety Survey- UtilityPULSE

In 2020, 2022, and 2024, EPLC conducted its periodic Public Awareness of Electrical Safety Survey via one-on-one scripted telephone surveys. The most recent survey was conducted in February 2024, and ended in March 2024. The survey covers topics such as a customer's likelihood to "call before you dig", knowledge of impacts to touching a power line, proximity to overhead power lines, actions taken in vehicle collisions with electrical equipment, among other relevant safety topics. The results are based on an online survey among 480 members of the general public, 18 years of age or older, within EPLC's service territory.

According to the 2024 results, EPLC's Public Safety Awareness Index Score was 85%. Essex Powerlines will continue to educate its customers on electrical safety awareness through its various programs and social media platforms. Additionally, EPLC has used this information to continue to invest and plan in the safety of its distribution system, to ensure customer and employee safety is top of mind when carrying out work.

Customer Engagement Survey- Innovative Research Group

Essex Powerlines Corporation engaged Innovative Research Group (IRG) to conduct an online customer survey seeking customers' input on their interests, needs, and priorities as it relates to EPLC's business operations. As a result, EPLC analyzed the survey data to ensure that customers' priorities are aligned with and represented in EPLC's business plan. The survey was conducted between November 2023 and ended early December 2023, engaging 1,874 residential and 21 general service (under 50 kW) customers.

The online survey was designed to gather customer interests and use the results to support EPLC's business planning and be incorporated in its 2025-2029 Distribution System Plan. The survey covered a range of topics including, but not limited to, reliability, affordability, electrification, and safety of the distribution system. Customers were informed of the survey through an email campaign, as well as site-wide notifications on the Essex Powerlines' website.

EPLC believes that the Rate Application Survey has provided sufficient evidence and detail of customer needs and preferences. The survey was longer in duration than typical surveys, spanning many topics to get a true understanding of customer needs. Additionally, the survey had an impressive response rate, with almost 1900 total respondents, which is more than what the average or typical response rate is for surveys of this nature. Because of this, EPLC believes the survey provided solid evidence to inform its utility planning and therefore, did not seek to complete a second survey. EPLC has reviewed the survey results with its planning team and has incorporated the customers' needs and preferences within its plans to ensure benefits are delivered to its customers. EPLC is confident that the investments suggested in its distribution system plan will help increase reliability, provide better customer service, and take into consideration future electricity needs as electrification becomes more prominent. For survey results, please refer to the below section.

Survey Results

Results from the customer survey and other engagement activities have been considered during the development of the capital plan and incorporated into EPLC's strategy accordingly. Projects that were prioritized will continue to add value to customers through increased grid reliability, maintaining affordable rates, and improved customer experience. The results of the survey can be found in Attachment 1-H, Appendix 2AC- Application Specific Customer Engagement Activities Summary.

Below outlines some of the highlights from the Customer Engagement Survey:

- 2-in-3 residential customers said they were satisfied with the overall services Essex Powerlines provides.
- When asked about areas that can be improved upon, 33% of residential customers said more reliable service, while 42% were unsure.
- Ensuring reliable electrical service, delivering reasonable electricity distribution prices, replacing aging infrastructure, and investing in infrastructure and technology to better help withstand impacts of adverse weather were declared the top priorities that were most important to EPLC customers.
- The top priorities based on customer ranking for investing in new technology included investing in technology to help find efficiencies and reduce customer costs, to reduce the number and length of outages, and to help customers better manage their electricity usage.
- 3-in-10 customers said they are at least somewhat likely to invest in EVs in the next five years
- 56% percent of residential customers and 11 of 21 small business customers said the best form of communication for outage information would be via text message, while 52% of residential customers said the email or newsletter would be the best way to communicate other news/information.

Based on the online survey results, EPLC's business plans to enhance the grid and provide an augmented consumer experience through reliability, affordability, and technological change is supported through its customer base. It is understood that Essex Powerlines needs to:

- Continue to advance its infrastructure and invest in technologies that help create and maintain resilient services for its customers and prepare for the future of electrification. This includes, but is not limited to, investing in control room services, proactively replacing aging infrastructure, investing in SmartMAP and other software technologies to increase visibility into the grid and collect data on asset health, weather normalization, etc., and investing in technologies and tools to effectively manage and prepare for extreme weather events (such as technologies that integrate the DSO pilot into the operating activities of EPLC).
- Enhance and invest in tools and technology that augment the consumer experience. This includes, but is not limited to, investing in control room services, investing in a consumer engagement

platform (including a customer app and text messaging notifications), fully digitize customer forms, and increase methods of customer communication.

- Invest in the modernization of processes within the utility to create efficiencies for ratepayers. This includes, but is not limited to, investing in EPLC's Work Centre to automate job packages, automate existing DSP processes, provide ongoing load forecasting, and develop a map-based design estimating tool, as well as investing in technology that will permit ongoing improvements to the distribution system analytics, such as outage management, distribution system planning and prioritization, and condition-based asset planning.
- Continue to improve customer communications by connecting with residential and commercial/industrial consumers on a more frequent basis and tailoring those communications to meet the needs of the specific customer base. For instance, commercial/industrial consumers would like to have increased communication on EPLC's plans to effectively manage the grid as it relates to the future of electrification, while residential consumers would like more information on how to effectively reduce their consumption and electricity bills.

Overall, the Customer Engagement Survey helped inform EPLC's business plans and proceeded as one of the driving forces behind EPLC's top priorities and projects.

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, EPLC has presented its performance for each of the Board's performance outcomes over the last five years, including discussions on current performance, and projections for continuous improvements over the term of the Application.

1.6.2 Scorecard

The Scorecard Approach, issued on March 5, 2014, details the scorecard measures approach which the Board expects to use 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, and SAIDI and SAIFI have a trend indicator to identify how each LDC is trending in comparison to previous years. EPLC reviews these metrics yearly to identify positive trending results and those that may require areas of improvement.

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

https://essexpowerlines.ca/about/regulatory-affairs/scorecard/

Table 1-16 below provides EPLC's 2018 to 2022 performance on its Scorecard metrics as reported to the OEB in the annual RRR filings. EPLC's Scorecard, including its MD&A for 2022 is provided as Attachment 1-C.

Table 1-16: EPLC 2018-2022 OEB Scorecard Results

Performance Outcomes	Performance Category	Performance Year	2018	2019	2020	2021	2022
CUSTOMER FOCUS	Service Quality	New Residential/Small Business Services Connected on Time (Target: 90%)	91.18%	94.78%	93.27%	90.84%	91.45%
		Scheduled Appointments Met on Time (Target: 90%)	94.79%	93.15%	94.46%	93.15%	98.68%
		Telephone Calls Answered on Time (Target: 65%)	87.67%	82.62%	65.17%	76.62%	80.94%
	Customer Satisfaction	Billing Accuracy (Target: 98%)	98	100	99.92	99.95	99.95
		First Contact Resolution	98.52%	98.99%	99.15%	99.08%	99.60%
		Customer Satisfaction Survey Results	83%	83%	86%	86%	86%
OPERATIONAL EFFECTIVENESS	Safety	Level of Public Awareness			83%	85%	85%
		Level of Compliance with Ontario Regulation 22/04 (Target: substantially compliant)	C	C	C	C	C
		Number of General Public Incidents	0	0	0	0	0
		Rate per 10, 100, 1000 km of line	0	0	0	0	0
	System Reliability	Average Number of Times Power to Customer is Interrupted	1.29	0.84	0.95	0.89	0.84
		Average Number of Hours Power to Customer is Interrupted	1.82	1.27	1.23	2.02	1.82
	Asset Management	Distribution System Plan Implementation on Progress	18.80%	37.50%	57	76.13%	97.65%
	Cost Control	Efficiency Assessment (1 = most efficient 5 = least efficient)	2	2	2	2	1
		Total Cost ($) per Customer	578	580	577	564	625
		Total Cost ($) per Km of Line	37960	10907	10979	10789	12005
PUBLIC POLICY RESPONSIVENESS	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed on Time			100%		
		New Micro-Embedded Generation Facilities Connected on Time (Target: 90%)	100	100			100
FINANCIAL PERFORMANCE	Financial Ratios	Liquidity: Current Ratio	0.67	0.57	0.72	0.76	0.86
		Leverage: Total Debt to Equity Ratio	1.1	1.31	1.32	1.25	1.27
		Profitability: Regulatory Return on Equity - Deemed	9.00%	9.00%	9.00%	9.00%	9.00%
		Profitability: Regulatory Return on Equity - Achieved	8.11%	7.30%	6.14%	6.79%	6.09%

1.6.3 Customer Focus

Service Quality

In all measures of Service Quality, EPLC has exceeded OEB industry targets (where they have been established). In 2022, EPLC connected 91.45% of low voltage residential and small business customers within the five-day timeline prescribed by the OEB, showing an improvement over the same metric from 2021 which was 90.84%. For the measure of scheduled appointments met on time, EPLC scheduled 152 customer related appointments in 2022 and attended 98.68% of those appointments on time. This is an improvement over that same measure in 2021 and the 5-year trend is upward.

EPLC's customer service call centre received 20,537 calls in 2022 and 80.94% were answered within 30 seconds. This is a marked improvement over 2021 performance where 76.62% were answered within the

30 second timeframe. Considering the significant challenges that EPLC navigated in continuing to operate a call centre as staff migrated to remote work and changing requirements due to the Covid -19 pandemic, EPLC has consistently outperformed the OEB metric of 65% in this category and the 3-year trend is continually improving.

EPLC's target for these metrics in 2025 is to continue to exceed the industry target and to maintain current performance.

<u>Customer Satisfaction</u>

EPLC interprets the spirit of the metric on First Contact Resolution to be to identify a distributor's effectiveness at satisfactorily addressing customers' outreach upon first contact with a distributor. EPLC assesses the metric of First Contact Resolution based on the number of calls received and how many of these calls require escalation to a supervisor. In 2022, 99.60% of calls received by EPLC were resolved without escalation to a supervisor. EPLC's ongoing target for this metric is to exceed 99% consistently.

For 2022, EPLC issued 377,745 customer bills and achieved Billing Accuracy of 99.95%. This metric is high and flat for the 5-year period depicted above. EPLC expects to maintain this high level of Billing Accuracy going forward.

Customer Satisfaction Surveys are required to be completed on a bi-annual basis and are meant to examine customer satisfaction levels in the following key areas: power quality and reliability, price, billing and payment, customer service experience, communications, and price. The purpose of the survey is to solicit actionable and measurable feedback from customers. Information received through the survey is incorporated into EPLC's planning processes and is used as the basis for improvement to the overall customer experience and to the satisfaction levels that result. For example, in response to the question, "Is there anything in particular that you would like Essex Powerlines to do to improve its service to you?", 21% of respondents said they would like improved reliability/improved time to restore power. This is 10% higher than the next most common response. Metrics like these are significant indicators of where activities should be aimed at improving customer experience and are therefore used to inform planning at EPLC.

In 2023, EPLC engaged an independent third-party service provider to conduct the survey on its behalf. During the survey, a total of 413 random telephone surveys were completed with 378 residential customers and 35 general service (under 50kW) customers.

Survey results indicate that 87% of customers are satisfied with EPLC. EPLC's target for customer satisfaction is to maintain the 87% satisfaction rating it has received in 2023.

1.6.4 Operational Effectiveness

Safety

The public safety measure was introduced by the OEB in 2015 and provides several metrics: Component A – Public Awareness of Electrical Safety; Component B – Compliance with Ontario Regulation 22/04; and Component C - Serious Electrical Incident Index.

Component A – Public Awareness of Electrical Safety is an assessment of the safety of the distribution system from the customers' point of view and is measured through the results of a survey which is completed bi-annually. In 2024, EPLC engaged a third-party to conduct this survey on its behalf. 480 residents within EPLC's service territory, 18 years of age or older, were randomly surveyed via an online platform. The survey's focus was to measure the public's level of awareness regarding key electrical safety precautions. The results indicated that 85% of the public are aware of Electrical Safety, showing a consistent score in comparison to the 2022 result.

Component B - Compliance with Ontario Regulation 22/04 Electrical Distribution Safety, ("O.Reg. 22/4" or "the Regulation") 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 to determine the status of compliance.

EPLC compliance with the Regulation is audited annually by an independent consultant selected by the ESA. These audits will yield an outcome of Not Compliant, Needs Improvement or Compliance. In 2022, EPLC received an audit result of Compliant, indicating that EPLC substantially meets the requirements of O.Reg. 22/04. This result is consistent with prior years.

EPLC's target is continued Compliance with O.Reg. 22/04 as safety is a core value at EPLC and its importance is highlighted through the daily operations at the distributor.

Component C – Serious Electrical Incident Index is a measure of required reporting (under Section 12 of O. Reg. 22/04) of any serious electrical incident of which they become aware within 48 hours after the occurrence. As assessed by ESA, in the 2022 reporting period, there were zero reportable serious electrical incidents.

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

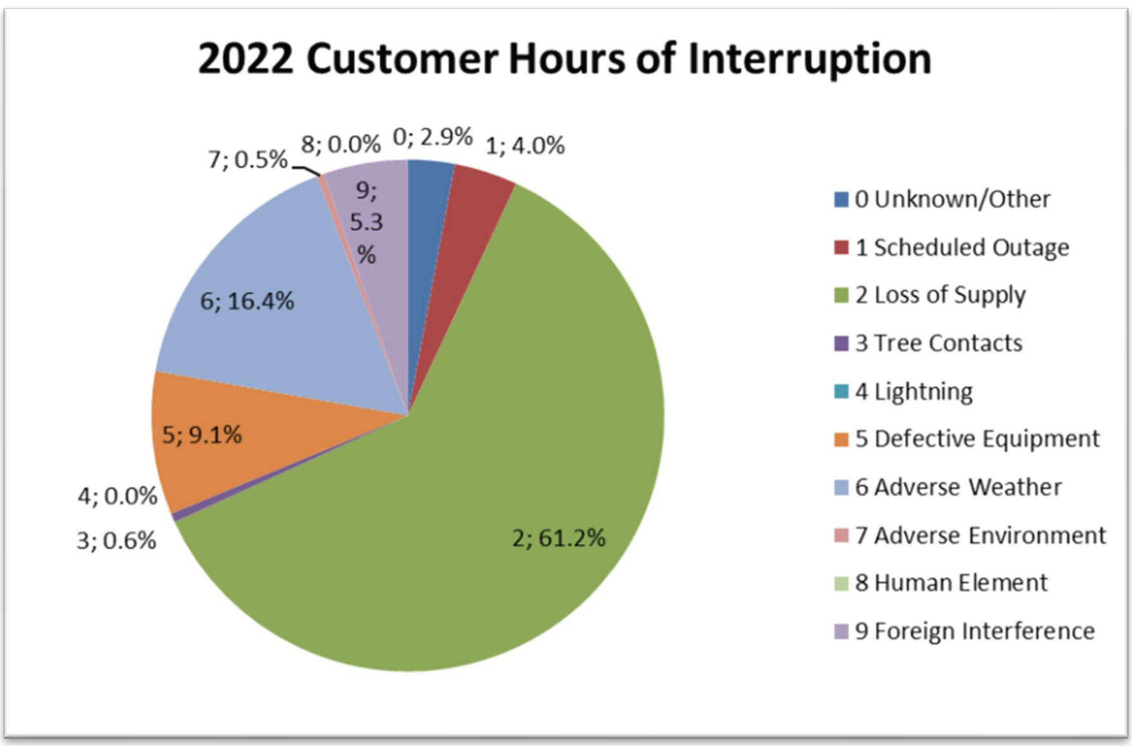
EPLC's target for this metric in 2025 is to have zero (0) serious electrical incidents reported.

<u>System Reliability</u>

System reliability is assessed with two metrics: The average duration of outages – System Average Interruption Duration Index (“SAIDI”) and the number of times power to a customer is interrupted – System Average Interruption Frequency Index (“SAIFI”).

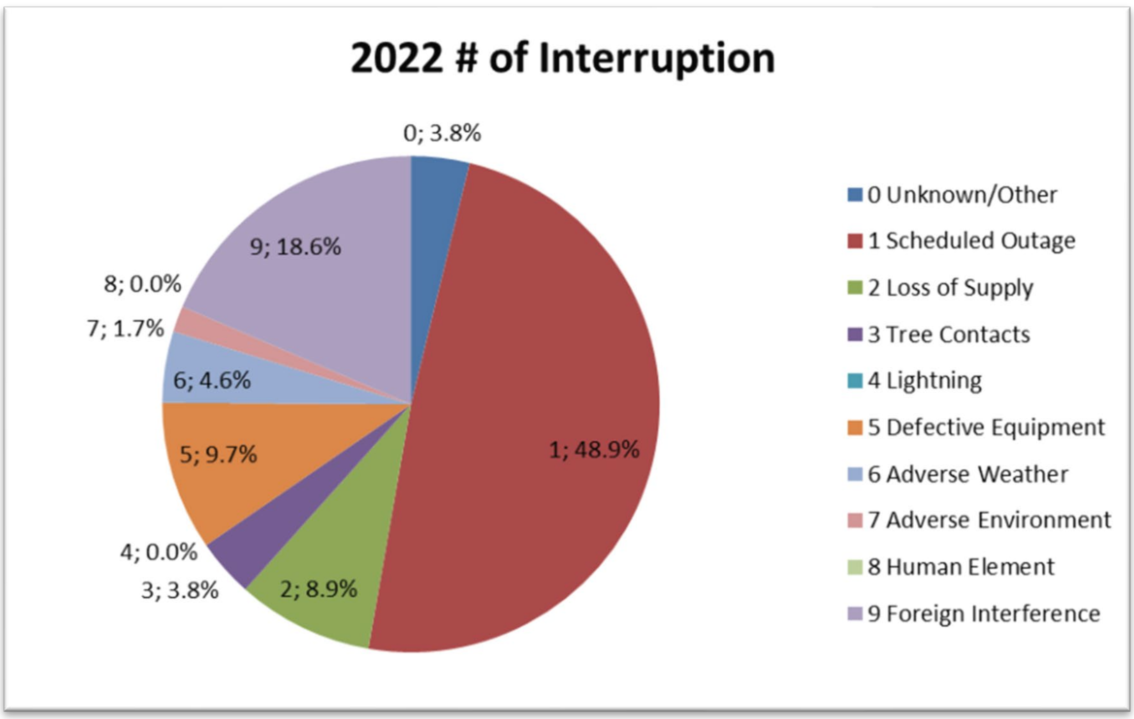
EPLC experienced a decrease in the average number of hours where power to a customer was interrupted, which was 1.82 in 2022 compared to 2.02 in 2021. EPLC’s current five-year average is 1.63 hours which is higher than the last year’s five-year average, and above the target of 1.24. Loss of supply (outside of EPLC’s service territories) has historically been, and continues to be, the largest contributor to this metric. In 2022, 61.2% (an increase from 57.2% in 2021) of the total number of hours power was interrupted was the result of a loss of supply event. All other sources of customer interruptions are noted in Figure 8 below. Scheduled outages, foreign interference, and adverse weather events are some of the various incidents that can affect this metric. EPLC’s Distribution System Plan (“DSP”), Reliability Centered Maintenance (“RCM”) and Asset Management Programs are designed to reduce these occurrences.

Figure 1-8: Customer Hours of Interruption



EPLC experienced a slight decrease in the Average Number of Times that Power to a Customer was Interrupted, which was 0.84 in 2022 compared to 0.89 in 2021. EPLC’s five-year average is 0.96, which has increased slightly compared to the previous five-year average and is above the target of 0.74. Scheduled outages, foreign interference (animal, vehicle, dig-ins), and defective equipment account for approximately 48.9%, 18.6% and 9.7% of the 2022 metric, respectively. All other sources of power interruption are noted in Figure 1-9 below. Consistent with the above, several incidents can affect this metric. EPLC's Distribution System Plan ("DSP"), Reliability Centered Maintenance ("RCM"), and Asset Management Programs are designed to reduce these occurrences.

Figure 1-9: Number of Interruptions



EPLC continues to focus on leveraging the planning tools mentioned above alongside considering and integrating innovative approaches to alleviating the impacts of loss of supply on its customers. The DSP that forms part of this Application specifically, is intended to heavily weigh this current challenge and the future additional constraints on supply that are anticipated in the coming years, while targeting to improve this metric.

<u>Asset Management</u>

Distribution System Plan Implementation Progress

Consistent with industry best practices, EPLC 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.

The DSP outlines the forecasted capital expenditures over the next five years required to maintain, improve, and expand EPLC's distribution system. EPLC measures the progress of its DSP implementation as a ratio of actual total capital expenditures and system O&M over the total amount of planned capital expenditures and system O&M for the five-year DSP forecast. The 2022 measure indicates that EPLC has completed 97.65% of its planned projected spend in its five-year plan.

EPLC has prepared a 2025-2029 DSP for filing with this Application and targets to continue to measure progress against that plan annual with the goal of meeting the requirements of the plan and achieving the desired outcomes based on system and customer needs.

Cost Control

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 econometric 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 1-16 below details the distribution of all distributors across the 5 groupings for 2022; there are 16 distributors in Group 1, 14 in Group 2, 19 in Group 3, 3 in Group 4 and 2 in Group 5.

Table1-17: Stretch Factor Assignments by Group

Stretch Factor Assignments by Group

Group I (16 Distributors)		Group II (14 Distributors)		Group III (19 Distributors)		Group IV (3 Distributors)	Group V (2 Distributors)
Stretch Factor = 0%		Stretch Factor = 0.15%		Stretch Factor = 0.30%		Stretch Factor = 0.45%	Stretch Factor = 0.60%
Cooperative Hydro Embrun Inc.	Lakefront Utilities Inc.	Burlington Hydro Inc.	**Kingston Hydro Corporation**	Alectra Utilities Corporation	London Hydro Inc.	Canadian Niagara Power Inc.	Algoma Power Inc.
E.L.K. Energy Inc.	**Milton Hydro Distribution Inc.**	**Centre Wellington Hydro Ltd.**	Lakeland Power Distribution Ltd.	Atikokan Hydro Inc.	Niagara Peninsula Energy Inc.	Hydro One Networks Inc.	Toronto Hydro-Electric System Limited
Entegrus Powerlines Inc.	Northern Ontario Wires Inc.	ENWIN Utilities Ltd.	Newmarket-Tay Power Distribution Ltd.	Bluewater Power Distribution Corporation	North Bay Hydro Distribution Limited	Hydro Ottawa Limited	
Essex Powerlines Corporation	Orangeville Hydro Limited	EPCOR Electricity Distribution Ontario Inc.	Niagara-on-the-Lake Hydro Inc.	**Chapleau Public Utilities Corporation**	Oakville Hydro Electricity Distribution Inc.		
Grimsby Power Incorporated	**Ottawa River Power Corporation**	**Fort Frances Power Corporation**	Oshawa PUC Networks Inc.	Elexicon Energy Inc.	PUC Distribution Inc.		
Halton Hills Hydro Inc.	Sioux Lookout Hydro Inc.	GrandBridge Energy Inc.	Rideau St. Lawrence Distribution Inc.	Enova Power Corp.	Renfrew Hydro Inc.		
Hearst Power Distribution Company Limited	Wasaga Distribution Inc.	Hydro 2000 Inc.	**Tillsonburg Hydro Inc.**	ERTH Power Corporation	Synergy North Corporation		
Hydro Hawkesbury Inc.	Welland Hydro-Electric System Corp.			Festival Hydro Inc.	Wellington North Power Inc.		
				Greater Sudbury Hydro Inc.	Westario Power Inc.		
				Innpower Corporation			

From 2012 to 2022, EPLC has been ranked in Group 2, which is the second most efficient grouping of Ontario Electricity Distributors. In 2023, EPLC achieved Group 1 ranking, the most efficient grouping of Ontario Electricity Distributors. EPLC is committed to maintaining its current efficiency ranking.

Table 1-18 below summarizes the OEB approved IRM increases for the years since the last rebasing application and the assigned cohort as per the PEG model for those historical years. This table also shows the predicted outcome based on projected costs 2023-2025 for EPLC. EPLC is predicted to remain in Group 1 for 2023 and 2024, and move back into Group 2 in 2025, based on planned spending as detailed throughout this Application.

Table 1-18: Summary of Inflationary Increases, Stretch Factors and Cohort Placements for 2018-2024 – PEG Benchmarking Forecast 2023-2025

	Inflationary Increase	Stretch Factor	OEB Approved IRM increase	Cohort Assignment
2018	1.20%	0.15%	1.05%	II
2019	1.50%	0.15%	1.35%	II
2020	2.00%	0.15%	1.85%	II
2021	2.20%	0.15%	2.05%	II
2022	3.30%	0.15%	3.15%	II
2023	3.70%	0.15%	3.55%	II
2024	4.80%	0.00%	4.80%	I

	2025 Projection	2024 Projection	2023 Projection
Total Cost	25,781,735	23,645,404	21,224,844
Prior Year Total Cost	23,645,404	21,224,844	19,472,877
Percentage Change in Total Cost	9.0%	11.4%	9.0%
Actual Cost	25,781,735	23,645,404	21,224,844
Predicted Cost	30,775,319	29,351,759	27,994,047
Actual Cost less Predicted Cost	(4,993,584)	(5,706,355)	(6,769,203)
Logarithmic Percentage Difference	-17.70%	-21.62%	-27.68%
3 Year Rolling Average	-22.3%	-27.0%	-30.3%

Table 1-19 below summarizes the cost implications per EPLC customer and per Km of EPLC line.

Total Cost per Customer is calculated as the sum of EPLC's capital and operating costs and dividing this figure by the total number of customers served. The cost performance result for 2022 is $625 per customer which is an increase of 10.82% over 2021 and is an overall average increase per year of 3.2% during the period from 2018 to 2022.

EPLC has experienced significant increases in material costs since the global pandemic, with a notable spike in costs in 2022. Additionally, some cost increases experienced are often directly related to industry-driven objectives and new legislated directives that require distributors to invest in assets, personnel, and technology to appropriately satisfy these new directives. Over the course of the past several years, examples of these changes would include customer focused engagement, cybersecurity, the implementation of Smart Meters, increased complexity for market settlement, and the adoption of new accounting standards. EPLC remains committed to implementing all new directives in the most cost-conscious manner possible.

EPLC's Total Cost per Km of Line is derived by dividing the total cost figure, arrived at as described above, by the kilometers of line that EPLC operates to adequately service its customers. EPLC's 2022 rate is $12,005 per km of line which is an increase of 11.27% over 2021. The reasons for the increase are similar to those described as impacting the Total cost per Customer.

Table 1-19: Total Costs per Customer and per Km of Line

Performance Year	Total Cost per Customer	Total Cost per Km of Line
2018	$ 578	$ 37,960
2019	$ 580	$ 10,907
2020	$ 577	$ 10,979
2021	$ 564	$ 10,789
2022	$ 625	$ 12,005

Benchmarking these costs against a cohort of utilities that are similar in size, similar in service territory composition, and by geographic proximity shows that EPLC is in the lower one-third of LDCs in that grouping. Table 1-20 below benchmarks total cost per customer and total cost per Km of line across the group from 2018-2022.

Table 1-20: 2018-2022 Cost per Customer and Cost per Km of Line Across Similar LDCs

	Total Cost ($) per Customer				
	2018	2019	2020	2021	2023
Bluewater Power Distribution Corp	$ 730	$ 734	$ 710	$ 714	$ 779
E.L.K. Energy Inc.	$ 402	$ 418	$ 380	$ 437	$ 559
Entegrus Powerlines Inc.	$ 563	$ 566	$ 553	$ 558	$ 627
EnWin Utilities Ltd.	$ 717	$ 709	$ 692	$ 675	$ 717
ERTH Power Corporation	$ 703	$ 691	$ 680	$ 676	$ 720
Essex Powerlines Corporation	$ 578	$ 580	$ 577	$ 564	$ 625
Westario Power Inc.	$ 575	$ 601	$ 588	$ 610	$ 691
	Total Cost ($) per Km of Line				
	2018	2019	2020	2021	2023
Bluewater Power Distribution Corp	$ 34,186	$ 34,186	$ 34,871	$ 21,695	$ 21,932
E.L.K. Energy Inc.	$ 30,795	$ 30,795	$ 31,613	$ 28,537	$ 31,789
Entegrus Powerlines Inc.	$ 26,787	$ 26,787	$ 10,982	$ 11,008	$ 10,670
EnWin Utilities Ltd.	$ 13,660	$ 13,660	$ 13,539	$ 13,236	$ 12,989
ERTH Power Corporation	$ 39,341	$ 39,341	$ 36,992	$ 36,142	$ 35,797
Essex Powerlines Corporation	$ 37,960	$ 37,960	$ 10,907	$ 10,979	$ 10,789
Westario Power Inc.	$ 24,850	$ 24,850	$ 25,517	$ 24,427	$ 25,340

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 and Connection of Micro-Embedded Generation Facilities within Five Business Days

Electricity distributors are required to conduct Connection Impact Assessments ("CIAs") within 60 days of receiving authorization for their project from the ESA. Distributors are also 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. EPLC has met these requirements consistently in past years.

EPLC's target for these metrics in 2023 is to complete all assessments within the prescribed timelines.

1.6.6 Financial Ratios

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 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.

EPLC's current ratio for 2022 is 0.85, up from 0.76 in 2021. This ratio has been trending upwards over the last five years as EPLC has adapted and secured more long-term financing to replace shorter-term borrowings in order to take advantage of historically low financing rates. EPLC's current ratio in 2022 has increased by 11.84% over 2021.

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

The OEB uses a deemed capital structure of 60% debt and 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 leveraged 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 leveraged 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.

EPLC's Total Debt to Equity ratio has experienced slight fluctuations over the past five years and is 1.27 for 2022. EPLC has intentionally maintained a low Debt to Equity ratio to minimize its annual interest costs and to remain flexible should unforeseen borrowing needs arise. EPLC's goal has been to increase its leverage closer to the approved ratio of 1.5.

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

The OEB allows a distributor to earn within +/- 3% of the expected rate of ROE. When a distributor performs outside of this range, the actual performance may trigger a regulatory review of the distributor's revenues and cost structure by the OEB. The allowed deemed return on equity decreased from 9.85% to

9.00% further to the OEB Final Rate Order EB-2017-0039 effective May 1, 2018, and implemented October 1, 2018.

Profitability: Regulatory Return on Equity – Achieved

EPLC's regulatory ROE achieved in 2022 was 6.09%, which falls within the +/-3% range of the deemed ROE of 9.00%. EPLC's regulatory average ROE is 6.89% for the five-year period from 2018 to 2022.

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.

On October 11, 2023, the OEB published a new APB report with unit cost results updated by the OEB to include 2022 figures. EPLC submitted their 2022 data to fulfill the RRR requirement for Activity and Program Based Benchmarking where applicable. In the case of 'Stations' and 'Station Transformers', EPLC reported zero, and as such, no unit cost metric was calculated related to Stations O & M or Stations CAPEX. For the other programs, discussion of EPLC's unit cost indices and industry averages are detailed below.

Billing O & M – EPLC's 5-year average unit cost index is $25.96, while the industry 5-year average unit cost index is $26.43. EPLC is slightly below the industry average on this cost index and is satisfied that no remedial action is required in this area. Table 1-21 below benchmarks EPLC's Billing O&M per customer against similar LDC's. EPLC's is averaging at a cost that is almost equal to the average of the cohort.

Table 1-21: Billing O&M per Customer Benchmarking

	Billing O&M Cost ($) per Customer					
	2018	2019	2020	2021	2022	Average
Bluewater Power Distribution Corp	$ 27.91	$ 26.20	$ 25.67	$ 27.43	$ 28.03	$ 27.05
E.L.K. Energy Inc.	$ 31.95	$ 22.86	$ 20.24	$ 23.70	$ 22.88	$ 24.33
Entegrus Powerlines Inc.	$ 24.95	$ 18.57	$ 18.87	$ 22.34	$ 22.76	$ 21.46
EnWin Utilities Ltd.	$ 16.38	$ 16.27	$ 17.03	$ 17.05	$ 17.56	$ 16.86
ERTH Power Corporation	$ 52.98	$ 59.08	$ 52.22	$ 40.32	$ 42.60	$ 49.44
Essex Powerlines Corporation	$ 23.56	$ 22.87	$ 26.08	$ 26.88	$ 30.44	$ 25.96
Westario Power Inc.	$ 11.76	$ 16.16	$ 15.80	$ 14.87	$ 16.76	$ 15.07

Metering O & M – EPLC's 5-year average unit cost index is $9.77, while the industry 5-year average unit cost index is $13.96. EPLC is 30% below the industry average on this cost index, and in the last 3 years EPLC's average unit cost index is $8.16, indicating that the unit cost has been even lower since the beginning of the pandemic. This reduction in unit cost can be directly attributed to supply chain constraints and the reduction in metering work that was performed during the pandemic. A close review of the trend shows the unit cost dropping notably at the start of the pandemic and then a slow year-over-year increase in costs. Although costs have not yet recovered to pre-pandemic levels, and are not near the industry average, no specific activities are identified as necessary in this area.

When benchmarked against similar LDC's, EPLC's average Metering O&M per customer is second lowest in the group.

Table 1-22: Metering O&M per Customer Benchmarking

	Metering O&M Cost ($) per Customer					
	2018	2019	2020	2021	2022	Average
Bluewater Power Distribution Corp	$ 22.16	$ 20.67	$ 20.23	$ 22.42	$ 22.63	$ 21.62
E.L.K. Energy Inc.	$ 19.75	$ 19.75	$ 18.98	$ 17.99	$ 21.13	$ 19.52
Entegrus Powerlines Inc.	$ 9.32	$ 6.51	$ 7.79	$ 7.12	$ 6.19	$ 7.39
EnWin Utilities Ltd.	$ 14.62	$ 15.88	$ 15.03	$ 14.47	$ 16.13	$ 15.23
ERTH Power Corporation	$ 14.27	$ 18.56	$ 18.40	$ 27.38	$ 22.54	$ 20.23
Essex Powerlines Corporation	$ 12.95	$ 11.41	$ 8.07	$ 7.60	$ 8.82	$ 9.77
Westario Power Inc.	$ 23.23	$ 23.67	$ 18.62	$ 17.30	$ 21.65	$ 20.89

Vegetation Management O & M - EPLC's 5-year average unit cost index is $71.03, while the industry 5-year average unit cost index is $67.76. EPLC is slightly above the industry average in this cost index. This does not necessarily indicate a problem or an area that requires focus in terms of remediation. EPLC current does not have insights into why its vegetation management average unit cost is higher than the industry average. One contributing factor may be the non-contiguous service territories that EPLC services. Benchmarking EPLC's vegetation management O&M reveals that it is second highest in the group. EPLC will discuss its tree trimming program with other distributors that are lower than the average in this category.

Table 1-23: Vegetation Management O&M Benchmarking

	Vegetation Management O&M Cost ($1,000)					
	2018	2019	2020	2021	2022	Average
Bluewater Power Distribution Corp	$ 277.60	$ 238.00	$ 178.40	$ 241.30	$ 365.70	$ 260.20
E.L.K. Energy Inc.	$ 59.60	$ 54.10	$ 64.70	$ 128.40	$ 260.30	$ 113.40
Entegrus Powerlines Inc.	$ 280.20	$ 270.70	$ 115.50	$ 198.90	$ 459.30	$ 264.90
EnWin Utilities Ltd.	$ 940.60	$1,044.60	$1,019.90	$1,244.10	$1,019.10	$1,053.60
ERTH Power Corporation	$ 205.40	$ 144.20	$ 143.80	$ 149.70	$ 189.40	$ 166.50
Essex Powerlines Corporation	$ 477.10	$ 460.90	$ 400.60	$ 407.10	$ 466.30	$ 442.40
Westario Power Inc.	$ 125.90	$ 153.30	$ 316.80	$ 278.00	$ 378.90	$ 250.60

Lines O & M - EPLC's average cost ($1,000) is $776.3, while the industry average cost is $3,889.5. Comparison of EPLC's cost in this metric against similar LDC's shows that there is considerable variation in costs. This can be attributed to the composition of local distribution systems.

Table 1-24: Lines O&M Benchmarking

	Lines O&M Cost ($1,000)				
	2019	2020	2021	2022	Average
Bluewater Power Distribution Corp	$1,543.10	$1,654.20	$1,417.60	$1,718.90	$1,538.30
E.L.K. Energy Inc.	$ 746.90	$ 484.00	$ 559.80	$ 627.50	$ 496.90
Entegrus Powerlines Inc.	$1,656.50	$1,734.60	$1,915.30	$1,967.20	$1,768.80
EnWin Utilities Ltd.	$3,746.90	$4,175.10	$3,551.30	$4,091.80	$3,824.40
ERTH Power Corporation	$ 667.60	$ 843.60	$ 672.60	$ 756.20	$ 727.90
Essex Powerlines Corporation	$ 778.10	$ 742.20	$ 808.50	$1,179.10	$ 776.30
Westario Power Inc.	$ 825.70	$ 767.60	$ 719.20	$ 987.90	$ 770.80

Poles, Towers O & M - EPLC's 5-year average unit cost index is $9.97, while the industry 5-year average unit cost index is $11.65. EPLC does not have insights into why its Poles and Towers O & M is lower than the industry average. EPLC will review spending in this category to ensure that it is adequate and that reported figures are accurate to ensure that this average unit cost is both accurate and that it can be maintained while ensuring poles are maintained/replaced as needed and as appropriate.

Benchmarking the total cost (per $1,000) shows that there is considerable variation in the category. This can be attributed to the differing composition of distribution systems.

Table 1-25: Poles, Towers O&M Benchmarking

	Poles, Towers O&M Cost ($1,000)					
	2018	2019	2020	2021	2022	Average
Bluewater Power Distribution Corp	$ 5.50	$ 11.80	$ 6.50	$ 7.70	$ 3.30	$ 8.40
E.L.K. Energy Inc.	$ 23.90	$ 30.10	$ 38.90	$ 40.80	$ 69.60	$ 33.30
Entegrus Powerlines Inc.	$ 60.10	$ 152.20	$ 106.40	$ 120.60	$ 167.50	$ 101.90
EnWin Utilities Ltd.	$ 554.30	$ 576.20	$ 937.50	$1,009.80	$1,095.90	$ 769.50
ERTH Power Corporation	$ 74.50	$ 85.40	$ 64.30	$ 65.50	$ 83.70	$ 70.50
Essex Powerlines Corporation	$ 32.10	$ 85.20	$ 79.30	$ 32.90	$ 97.50	$ 62.40
Westario Power Inc.	$ 126.50	$ 170.20	$ 150.20	$ 116.10	$ 169.00	$ 154.90

Poles, Towers CAPEX - EPLC's 5-year average unit cost index is $6,641.00, while the industry 5-year average unit cost index is $10,744.40. Within the group of similar LDC's, EPLC's Poles Capex unit cost is lowest.

Table 1-26: Poles Capex Unit Cost Benchmarking

	Poles Capex Unit Cost ($/pole addition)					
	2018	2019	2020	2021	2022	Average
Bluewater Power Distribution Corp	$ 8,190	$ 7,724	$ 11,460	$ 10,793	$ 10,699	$ 9,773
E.L.K. Energy Inc.	$ 8,191	$ 5,592	$ 5,726	$ 7,678	$ 13,350	$ 8,108
Entegrus Powerlines Inc.	$ 2,587	$ 6,429	$ 6,713	$ 8,201	$ 11,941	$ 7,174
EnWin Utilities Ltd.	$ 10,455	$ 12,501	$ 16,501	$ 7,356	$ 8,307	$ 11,024
ERTH Power Corporation	$ 8,892	$ 8,515	$ 10,449	$ 7,763	$ 8,511	$ 8,826
Essex Powerlines Corporation	$ 6,353	$ 5,598	$ 8,339	$ 5,655	$ 7,257	$ 6,641
Westario Power Inc.	$ 6,427	$ 7,533	$ 7,363	$ 8,923	$ 23,382	$ 10,726

Line Transformers CAPEX - EPLC's 5-year average unit cost index is $15,377.60, while the industry 5-year average unit cost index is $17,898.90, (excluding Hydro One and Rideau). Benchmarking against similar LDC's shows that EPLC's Line Transformer Capex unit cost is among the highest. This may be because of the dis-contiguous service territories that EPLC services. EPLC will continue to monitor this metric and consult LDCs that are similar size and in close geographical proximity. Also, collaboration with other LDC's that serve multiple small service territories may aid in understanding what drives this cost.

Table 1-27: Line Transformers Capex Benchmarking

	Transformers Capex Unit Cost ($/line transformer addition)					
	2018	2019	2020	2021	2022	Average
Bluewater Power Distribution Corp	$ 8,816	$ 13,642	$ 19,044	$ 16,846	$ 29,231	$ 17,515
E.L.K. Energy Inc.	$ 8,599	$ 7,996	$ 9,426	$ 13,621	$ 17,921	$ 11,495
Entegrus Powerlines Inc.	$ 7,546	$ 10,800	$ 9,645	$ 15,925	$ 14,183	$ 11,619
EnWin Utilities Ltd.	$ 12,327	$ 14,329	$ 10,828	$ 12,882	$ 14,276	$ 12,928
ERTH Power Corporation	$ 9,559	$ 8,252	$ 7,212	$ 10,269	$ 7,422	$ 8,542
Essex Powerlines Corporation	$ 12,077	$ 15,187	$ 11,952	$ 14,682	$ 22,990	$ 15,377
Westario Power Inc.	$ 4,668	$ 4,732	$ 5,255	$ 4,612	$ 10,656	$ 5,984

Meters CAPEX- EPLC's 5-year average unit cost index is $12.88, while the industry 5-year average unit cost index is $18.29 (excluding Hydro One and Rideau). EPLC currently has no visibility into why its meters CAPEX would be lower than the industry average. Certainly, cost differences between AMI systems and the associated meter costs can vary significantly. Additionally, the percentage of residential versus commercial & industrial meters will influence this metric for all distributors. Residential meters are lower cost and less costly to install while commercial & industrial meters are more expensive to purchase and install. If a distributor has a customer base comprised of a higher percentage of commercial & industrial customers, they will therefore have higher costs than average for meters CAPEX.

Benchmarking of Meter CAPEX cost per customer shows that among similar LDC's, EPLC is very close to the 5-year average of that group.

Table 1-28: Meters Capex Benchmarking

	Meters Capex unit cost per Customer)					
	2018	2019	2020	2021	2022	Average
Bluewater Power Distribution Corp	$ 7.48	$ 7.95	$ 12.50	$ 4.91	$ 5.13	$ 7.59
E.L.K. Energy Inc.	$ 7.46	$ 3.38	$ 5.62	$ -	$ 6.44	$ 5.73
Entegrus Powerlines Inc.	$ 12.08	$ 14.23	$ 10.74	$ 21.39	$ 6.99	$ 13.09
EnWin Utilities Ltd.	$ 7.28	$ 6.45	$ 11.60	$ 8.50	$ 9.96	$ 8.76
ERTH Power Corporation	$ 19.03	$ 22.21	$ 22.29	$ 24.68	$ 28.63	$ 23.37
Essex Powerlines Corporation	$ 12.48	$ 13.98	$ 14.33	$ 15.47	$ 8.14	$ 12.88
Westario Power Inc.	$ 12.80	$ 7.69	$ 17.26	$ 3.81	$ 5.64	$ 9.44

Conclusion

The data provided by Activity and Program-Based Benchmarking of distributor performance against industry averages provides one important view of distributor performance. Other essential considerations, such as geographic location, customer composition, and the important key outcomes of reliability and customer satisfaction are additional significant influences on overall performance.

1.7 Facilitating Innovation

Introduction

In consideration of the OEB's objective of facilitating innovation in the electricity sector, as outlined in the December 8, 2020, section 1 of the *Ontario Energy Board Act, 1998* (the Act), EPLC has incorporated innovative approaches to electricity distribution within this Application in several ways. The first approach, underpinning activities across various planning areas, is process automation / improvement. The second notable approach to innovation that has shaped this Application is EPLC's advancement in addressing local constraints through the PowerShare Project. Innovation has shaped this Application by permitting EPLC to view electricity distribution through a different lens; with an eye to enhancing how EPLC meets the needs of customers.

1.7.1 Process Automation/Improvements

Under the broad umbrella description of process automation and improvements, EPLC's innovative approach to leveraging and enhancing existing software tools in combination with implementation and deployment of new smart devices results in distribution system innovation that truly moves beyond the traditional poles and wires approach and into a near real time, customer centric energy management system. These investments and the associated planning will unlock the value in previous investments, improve response times and shift focus from reactive to proactive activities.

Building on previous investments in software tools such as SmartMAP and enhancing the capabilities both with, and surrounding, that system will enable EPLC to operate SmartMAP as a key component in its control room activities and will provide real-time data access and load flow visibility in the distribution system. Further, investments in installation of area-wide reclosers and real-time automation control will modernize EPLC's distribution network and enable improved response time to incidents or outages and improved reliability overall. This work will bring together forward-looking planning activities and customer focused delivery improvements.

The value of both previous and planned investments in process automation and improvements to existing tools results in demonstrable efficiency and cost control in Operations and Maintenance costs. Exhibit 2 of this Application details this data, as EPLC's Operations and Maintenance forecast expenditures for the 2025 Test Year are only a slight increase over the 2018 OEB Approved amount.

1.7.2 PowerShare, A Distribution System Operator (DSO) Project

In response to a 2021 joint targeted call from the OEB Innovation Sandbox and the IESO Grid Innovation Fund, EPLC created an innovative project called PowerShare. Through this project, EPLC will undertake activities of a Distribution System Operator (DSO).

The DSO in the Ontario Distribution System

Essex Powerlines, like many other LDC's and regions of Ontario, is facing constraints in their distribution system that cannot be addressed by traditional poles and wires solutions. To meet the challenges associated with the predicted doubling of load in the Kingsville/Leamington area by 2035[17], as well as the already existing overloaded feeders in that same area; Essex Powerlines is looking to the future of the Local Distribution System and seeking innovative solutions to meet the growing demand for electricity.

One of those solutions is the creation and operation of a Local Energy Market (LEM) to support local needs. Implementation of this solution began with the development of PowerShare, a Distribution System Operator (DSO) project, in the Essex Powerlines territory, funded through the generous support of the OEB and the IESO. The learnings from this project have informed and continue to inform EPLC's planned full scale, integrated implementation of a DSO.

The IESO, in its DER Potential Study, notes that there already exists enough DER capacity to accommodate to anticipate (up to)4.3GW of peak summer demand (by 2032)[18] by leveraging Distributed Energy Resources that already exists in the province. Leveraging innovative opportunities to distribute that power locally to address supply issues will ultimately alleviate broader constraints on the entire provincial system. Additionally, the opportunity to reduce investments in traditional infrastructure-based

[17] Windsor-Essex Region Integrated Regional Resource Plan (September 2019) https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/Windsor_Essex_IRRP_Report_20190903.ashx
[18] Ontario's Distributed Energy Resources (DER) Potential Study Volume I: Results & Recommendations September 28, 2022, https://www.ieso.ca/-/media/Files/IESO/Document-Library/engage/derps/derps-20220930-final-report-volume-1.ashx.

transmission solutions will aid in advancing the electricity sector toward carbon goals and bridge the gap between what needs to be built to service the expected demand for electricity.

What is a DSO?

DSO means Distribution System Operator. In Ontario, this is the language used to capture the future state and function of an LDC in an electrified and highly interconnected power system.

A DSO is an organization which can monitor, plan, and manage their system in near-real time. The difference between an LDC and a DSO is simply a suite of capabilities. These capabilities bring an LDC out of the traditional capital-expenditure dominated “Poles-and-Wires” model, and into a total-expenditure minded “Energy Management Services Enablement” model. Ultimately, this means a shift from the one-way delivery of power to bi-directional power flows between customers, DSOs, and the bulk system.

A local electricity market (called a “flexibility market” in *PowerShare*) is simply one of the services a DSO enables an LDC to provide or facilitate.

PowerShare as a DSO has been designed based on the principles of:

- *Flexibility First*, to move beyond strictly priced based signals to intrinsically consumer focused innovation that values optionality and voluntarism in distribution service provision. A natural hierarchy of flexibility will emerge that allows DSOs to activate tranches of resources (low cost/high voluntarism, high cost/low voluntarism, regulatory tools/no voluntarism) that scale with grid need. This approach recognizes that constraints and outages impose costs on consumers, and that these costs should be accounted for (‘internalized’) to the electricity system when addressing constraints and the resulting loss of supply, ultimately protecting consumers from costs in terms of unexpected outages.
- *Consumer Choice*, through market-based solutions that permit a bi-directional flow of power to meet needs.
- *Increased Reliability*, by meeting known needs through leveraging existing DERs, NWAs, and engaging consumers directly. Participation in DSO programs or tools will allow for visibility to placement and capabilities of DERs within the system, etc.

Project Development and Early Implementation

EPLC has begun its journey towards DSO activity at the crossroads of several influences. First, Essex Powerlines Corporation is well underway on its Digital Utility Transformation with a decade of building the systems to monitor, plan, and manage its system in near-real time. With the SmartMAP software integrations and enhancements as described above, EPLC is positioned to take further innovative steps in addressing customer focused system needs.

Second, EPLC has had the opportunity to demonstrate operation and thoughtfully define rules and contracts of a Local Energy Market through PowerShare, supported through funding from the IESO and the OEB's joint call in the Grid Innovation Fund. PowerShare is the first exploration of the role of a Distribution System Operator in managing distribution-connected DER flexibility services in local and provincial markets. As an outcome of the project, EPLC will have developed a platform that enables supervised automated trading based on actual identified needs and matches buy and sell orders based on defined parameters of price, location, and quantity.

Lastly, PowerShare aligns closely with the expected outcomes of the Ministry of Energy's renewed Letter of Direction[19] that was published on November 29, 2023. The Minister of Energy's letter has specified initiatives that were believed to be critical to the health of Ontario's energy sector and necessary for the OEB to prioritize. Some areas that the Ministry of Energy has specifically called out with the expectation to see significant progress includes, but is not limited to:

- **Facilitating Innovation within Ontario's Regulatory Framework.** The PowerShare project aligns with this objective in that it is an innovative concept that has not been tested in Ontario before. PowerShare is working with the OEB Innovation Sandbox as part of the Grid Innovation Fund to determine how such a project can work within the existing Regulatory Framework, and what exceptions would need to be made.
- **Distributed Energy Resources and Future Utility Business Models.** PowerShare is directly exploring the opportunity for future utility business models and how these business models can enable DERs and NWAs to solve local and provincial grid constraints. Additionally, PowerShare will enable consumers to better manage their energy costs by capitalizing on investments such as roof-top solar and BESS, electric vehicles, and responsive air conditioners and water heaters. While PowerShare is currently only testing participants with larger DER assets, it does envision a future where smaller assets can be aggregated into a participatory local energy market.
- **Electric Vehicles.** It is imperative that LDCs plan and build with the expectation that electrical demands per household will grow, especially with the increased uptake of electric vehicles. PowerShare explores an opportunity to alleviate local grid constraints by optimizing existing DER assets through local flexibility markets.
- **Red Tape Reduction.** EPLC's PowerShare project is partially funded through the joint targeted call between the IESO's Grid Innovation Fund and OEB's Innovation Sandbox. Being supported through the Innovation Sandbox, EPLC believes that red tape can be mitigated within the PowerShare project and can be used as a steppingstone and learning outcome in the greater scheme of burden reduction.
- **Distribution Sector Resiliency, Responsiveness, and Cost Efficiency**. A project such as PowerShare enables resiliency, responsiveness, and cost efficiency within an LDC's distribution system. PowerShare integrates, connects, and activates customer-owned DERs in a local flexibility market to relieve grid constraints in a prescriptive manner. By having a local energy market, resiliency and responsiveness to the grid should increase. Additionally, by utilizing

[19] Letter of Direction from the Minister of Energy to the Acting Chair (2023) https://www.oeb.ca/sites/default/files/letter-of-direction-from-the-Minister-of-Energy-20231129.pdf

existing DERs within the distribution network, there is potential to reduce and mitigate large buildout costs that would otherwise be needed to solve grid constraints.

Overall, the PowerShare project supports the direction of the energy industry and the learning outcomes are expected to help bolster and prepare the industry to meet environmental, societal and governance goals through the exploration of new utility business models.

How the PowerShare LEM works

The design philosophy for PowerShare was to capture distribution connected DERs which may otherwise be unable to provide grid services, such as in IESO administered markets (IAMs). Barriers to entry are anticipated to be reduced to demonstrate the existing ability of DERs to provide services, and distribution needs were reflected in the market design, and 'stacking' of IAM participation is simulated.

PowerShare has two products: near-real time delivery contracts (ShortFlex) and capacity availability contracts (LongFlex). Delivery offers and bids are matched on the parameters of price, location, and quantity, creating a transaction contract between the buyer (the DSO) and the seller (the flexibility service provider) for the delivery period. Periods are each a 30-minute interval beginning on the hour (08:00) and half-hour (08:30).

LongFlex is used to ensure availability of offers within the ShortFlex market at DSO-specified times.

The DSO (or its automated tools) will review the available offers against forecasted and actual grid needs for a day. The ShortFlex market closes two hours and five minutes (125 minutes) ahead of real-time to allow for coordination between the service provider, the DSO, and the simulated IESO.

Settlement occurs based on EPL's meter data, using 15- or 5-minute increments (the lowest available is used). Incentive to deliver is a diminishing payment based on verified percentage of delivery, where 90% or more of the contracted quantity delivered received 100% of the contracted price.

Where Flexibility is Found

Two varieties of Flexibility can be procured by the DSO within a LEM: curtailment and generation. Both varieties are matched on the basis of price, location, and quantity of grid needs through the LEM platform. The DSO may determine which variety is most appropriate for grid needs.

Curtailment

Much like Demand Response activity, participants may commit to curtail as one method of alleviating local constraints and will be compensated through the market for doing so. This activity can be leveraged during specific times of anticipated distribution congestion or feeder constraint. Curtailment includes Behind-The-Meter (BTM) generation activities which reduce facility demand.

Generation

Distribution-connected DERs with appropriate physical connection to inject power may participate by generating directly to the distribution system. This activity can be leveraged to mitigate transmission congestion to the greater region and address specific power quality concerns. When a contract is formed for generation, the contracted power is ultimately delivered to Essex Powerlines' rate payers or exits the system to be settled as kWhs with the host distributor.

Future Evolution of PowerShare

As work continues on the PowerShare project throughout the preparation of this Application and into the first few years of EPLC's rebasing period, innovation and evolution of the DSO and its associated Local Energy Market will likewise continue to develop. The essential learnings from the project are expected to inform the advancement of constraint focused regulation and unlock activities that will only serve customers more reliably and efficiently going forward.

This project has informed EPLC's plans by permitting a reconsideration or at least a delay of traditional investments; thereby serving customers with increased reliability through carefully planned spending. Some traditional investments will still be required to meet the demands of electrification provincewide, however, the activities proven through this project and through locally distributing power in this new way, is one approach to addressing customer needs, now and in the future.

EPLC plans to continue, as permitted through regulation and direction, to facilitate its customers' ability to choose innovative approaches such as PowerShare in how they receive electricity services.

1.8 Financial Information

1.8.1 Audited Financial Statements

EPLC has included its Audited Financial Statements for 2021, 2022 and 2023 as Attachments 1-D, 1-E and 1-F respectively.

1.8.2 Annual Report and MD & A

EPLC published its 2022 annual report in July of 2023, and it is attached herein as Attachment 1-G.

1.8.3 Rating Agency Report

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

1.8.4 Prospectuses and Information Circulars for Recent and Planned Issuances

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

1.8.5 Change in Tax Status

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

1.8.6 Existing Accounting Orders

EPLC has applied the accounting principles and used the categories of accounts in the Board's Accounting Procedures Handbook ("APH"), and the Uniform System of Accounts ("USoA") in the preparation of this Application.

EPLC does not currently have any distributor specific accounting orders for Deferral and Variance accounts that it is required to be following.

1.8.7 Departures From UsoA

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

1.8.8 Accounting Standards

EPLC transitioned to IFRS on January 1, 2015. This Application is being filed using MIFRS Accounting Standards. EPLC has prepared its historical financial statements from 2018 to 2023 along with the 2024 bridge year and 2025 test year in accordance with the Modified International Financial Reporting Standards ("MIFRS").

1.8.9 Accounting Treatment of Non-Utility Businesses

EPLC is involved in Non-Utility Businesses which include:

- Water Billing;
- Streetlight Maintenance;
- Renewable Generation

EPLC confirms that accounting for these activities is segregated from EPLC's rate regulated activities in accordance with the:

- OEB's Guidelines: Regulation and Accounting Treatments for Distributor-Owned Generation Facilities (G-2009-0300, September 15th, 2009);
- Accounting Procedures Handbook for Electricity Distributors (January 1st, 2012);
- Affiliate Relationships Code for Electricity Distributors and Transmitters (March 15, 2010);

EPLC's Application has been prepared in relation to the rate regulated entity only, separately from its parent company or any of its affiliates that are not regulated by the OEB. No amounts associated with Non-Utility Business have been included in the costs proposed for recovery in this Application.

1.9 Distributor Consolidation

EPLC 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 EPLC's departments and overall business continuity plan. EPLC acted 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. EPLC enacted a multitude of business continuity plans to protect the safety of its workers and to continue to operate a safe and reliable distribution system. EPLC operations and spending plans did have to be adjusted to accommodate the changing landscape of the pandemic. Some of the items are highlighted below. The paragraphs to follow outline how EPLC was affected in terms of its load forecast, OM&A, business operations, and capital spending and planning.

Load Forecast

A range of COVID variables were considered to account for the impacts triggered by the COVID-19 pandemic. These variables have been included in load forecasts used to set electricity distribution rates in Ontario. The extent to which consumption from March 2020 onward differed from typical consumption has been found to be related to the weather variables in those months for certain classes, particularly for the Residential class. A set of COVID/weather interaction variables were considered to capture the incremental consumption caused by people staying at home due to lockdowns and from the increase in people working from home, which has persisted after the prevalence of direct COVID impacts have subsided.

COVID variables were tested for each of the Residential, General Service <50kW, General Service >50kW, and Embedded Distributor rate classes. As such, some COVID flag variables were tested and found to be statistically significant for some classes. The following COVID flag variables were considered:

- A "COVID" variable equal to 0 in all months prior to March 2020, 1 in all months from March 2020 to December 2021, and 0.5 from January 2022 to December 2022, and 0 thereafter.
- A "COVID_AM" variable equal to 0 in all months prior to March 2020, equal to 0.5 in March 2020, equal to 1 in April and May 2020, 0.5 in each month from June 2020 to December 2021, 0.25 each month from January 2022 to December 2022, and 0 thereafter. This variable accounts for the relatively larger impact of COVID in the first two and a half months following the first lockdowns in March 2020.
- A "COVID_WFH" variable equal to 0 in all months prior to March 2020, equal to 0.5 in March 2020, equal to 1 each month from April 2020 to December 2020, 0.75 from January 2021 to December 2021, 0.5 from January 2022 to December 2022, and 0.25 thereafter. This variable is intended to

reflect the shift to "Work from Home", which had larger impacts through the summer of 2020 and continues to reflect ongoing impacts.

- A "COVID2020" variable equal to 0 in all months prior to March 2020, equal to 0.5 in March 2020, equal to 1 in April and May 2020, equal to 0.5 in June 2020, and equal to 0 in July 2020 and each month thereafter. This variable reflects the temporary impacts experienced by some customers, particularly larger customers.

The "HDD COVID" and "CDD COVID" variables are equal to the relevant HDD and CDD variables since March 2020, and 0 in all earlier months. The coefficients reflect incremental heating and cooling load consumed as people stayed home during the pandemic. These variables continue to December 2021 but are reduced to 50% of HDD and CDD in all months in 2022 and to 0 in 2023.

The "CWFH HDD" and "CWFH CDD" variables are COVID/weather interaction variables that are equal to the relevant HDD and CDD variables applied to the COVID_WFH. The variables are 0 in all months prior to March 2020, 50% of weather variables in March 2020, 100% of weather variables in April 2020 to December 2020, 75% of weather variables in 2021, and 25% of weather variables in 2022 and thereafter.

The COVID/weather interaction variables related to the "work from home" variable was found to be statistically significant and is used for the Residential rate class. The COVID variables were not found to be statistically significant for the General Service <50 kW, General Service > 50kW, or Embedded Distributor rate classes.

OM&A and Business Operations

EPLC's Leadership team was focused on monitoring and reviewing pandemic related concerns and adapting responses in managing the work environment while operating the distribution system to ensure the safety of employees and its service to its customers. A cross-functional team was created for this purpose. Critical focus on business continuity planning, and associated consideration of workplace policies and required accommodations for staff was priority one.

EPLC invested in the health and safety of its workers by allowing them to work from home where this was possible. This required a transition that increased costs to accommodate the work from home environment. EPLC also mandated 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 groupings to reduce possible exposure or cross infection if a worker were to get sick and these groupings were kept completely segregated from each other with the goal of continuing to service customers even if a portion of the workforce were affected. As with most businesses, EPLC purchased the necessary products to keep its workers safe such as masks, gloves, cleaners, and sanitizing products. These additional measures were outside EPLC's standard business practices, plans, and duties that were considered in the formulation of the OM&A budget and thus directly impacted spending and results in these categories for 2020 and 2021.

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 planned or 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 a 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. For some individuals and businesses, the pandemic has resulted in financial hardship, and as a result, EPLC has seen greater challenges for customers to pay their bills. Despite government programs available to assist customers, EPLC has seen an increasing trend in non-payment of accounts which has created larger overdue accounts and bad debts that EPLC continues to manage.

Capital Spending and Planning

Capital spending and capital planning were impacted by the pandemic. EPLC experienced significant supply chain issues and rising prices. Throughout, with the goal of still achieving the DSP approved as part of its 2018 rebasing application, EPLC made every reasonable effort to shift plans where possible and maintain the distribution system as appropriate and possible. These efforts resulted in some shifting of expenditures in terms of spending stream and/or timing. Emerging from the pandemic constraints has not fully been realized yet, with consistently high inflation rates and continued elevated pricing, however, EPLC continues to work to mitigate impacts to customer through careful planning and re-prioritization of work.

ATTACHMENTS

Attachment 1-A

EPLC 2024-2025 Business Plan

ESSEX POWERLINES CORPORATION

Business Plan

2024/25

| Powering Forward

Essex Powerlines 2024 – 2025 Business Plan

Executive Summary

The evolution of the Ontario utility industry is ongoing, and Essex Powerlines is fully engaged in both the challenges and the opportunities that accompany that evolution.

The landscape is one of increasing electrification, customer growth and supply challenges. Essex Powerlines (EPLC) will see its own customer base grow, through development and electric vehicle penetration and it must evolve the distribution system accordingly.

Intersecting that anticipated growth, EPLC is in the process of preparing its 2025 Cost of Service Application, which is the rate-rebasing activity required by the OEB, for delivery in April of 2024 (requesting rates for implementation January 1, 2025). In light of that Cost-of-Service Application, this business plan and its accompanying budgets are formulated to define strategic plans and financial outcomes for a period of 2 years, 2024 and 2025.

In recognition of the ongoing transformation of the Ontario electricity sector and the specific impacts that electrification brings to the customers of Essex Powerlines Corporation, the multi-year strategy of EPLC is defined as ***Powering Forward***. Under pressures of increased electrification and a growing customer base, Essex Powerlines has devised strategies built on three main pillars that inform areas of focus and activity. These pillars: Customer Focus, Reliability, and Powering Growth are the main drivers of activities at the distributor. These themes inform planning, decisions, and execution and will serve both required maintenance activities alongside evolution and innovation in the distribution system.

Customer Focus is a top priority for EPLC and informs decisions that are made at all levels of the distributor's operations. The customer-centric culture at EPLC is evident through ongoing customer engagement activities and community outreach including satisfaction and safety surveys; technology solutions leveraged to enhance the customer experience, such as a chat bot and outage center to inform customers of outage occurrences and restoration times on the customer portal; plus, an omni-channel approach to communication and feedback through multiple channels such as social media, press releases, and email. Through consultation with relevant parties and planning initiatives, EPLC anticipates growth of 0.8% of its customer base. As EPLC's customer base continues to grow, the distributor must remain vigilant in planning and executing all activities through the lens of customer satisfaction.

Reliability is another of the key strategic pillars in EPLC's business plan. Through customer engagement initiatives, EPLC customers have expressed a continued interest in improved reliability and with known increased electrification on the horizon, this will become an even higher priority. As detailed in numerous industry reports, there are concerns about the level of electrification and increasing demand which will lead to reduced reliability if action is not undertaken to consider those needs in planning. For example:

"Forecasted growth in electricity demand in Windsor-Essex and Chatham-Kent is significant."[1]

"Significant growth in the greenhouse sector in the Windsor-Essex region is expected to exceed existing transmission system capacity."[2]

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[1] Powering Ontario's Growth Report, Ministry of Energy 2023

[2] Reliability Outlooks (July 2022 to December 2023, and October 2023 to March 2025), IESO 2022 and 2023

"Local constraints in Windsor-Essex and Chatham restrict the ability to transport power to the entire West Zone."[3]

"Electricity demand in the region, particularly in Kingsville-Leamington, is growing rapidly due to agriculture and manufacturing development."[4]

"Demand is expected to exceed capacity."[5]

Thus, it is essential that EPLC plans for additional capacity requirements and rises to the challenges that will be faced in the near future. With current reliability statistics (both SAIDI and SAIFI) below OEB published distributor targets, EPLC is highly aware that this is an area of risk and has identified strategies to address this risk.

Powering Growth is the third strategic pillar in the business plan and is intended to focus on activities at EPLC that support the ongoing delivery of power as required, plus enable the evolution of EPLC to accommodate new opportunities due to growth of the customer base and to handle new challenges that will arise out of electrification. Achieving this strategic objective will require innovation and investments in scalable technology that will enable EPLC to meet increasing demand both flexibly and seamlessly. These necessary investments must be made prudently and in parallel with the Distribution System Plan (DSP) published as part of the Cost-of-Service application.

These themes come together through an outline that defines how EPLC can operate within the broader market but also leverage flexibility that is available locally to meet current and future needs, and thereby relieve constraints, deliver cost effective energy, and create a more local, although still very connected modernized distribution system.

2023 Highlights

In 2023, EPLC has achieved its previously established goals with investment, efforts, and achievements in transforming customer engagement, in advancing the PowerShare DSO project, and by making prudent investments to achieve cost efficiency.

Customer engagement was truly transformed during 2023. Implementation of the Green Button data standard was achieved and EPLC won the EDA Customer Service Excellence Award for implementation of the new phone system that enhances the customer experience and streamlines communication channels. In addition, in late 2022, EPLC launched its 24/7 chat support on its website, which started reaping benefits in early 2023. The results of the customer satisfaction survey confirm, with an 87% satisfaction rating, that EPLC is focused on the customer experience and planning appropriately to maintain customer satisfaction.

Work on the PowerShare DSO project also continued throughout 2023. The market rules were established and approved, unlocking the next phase of the project and the platform was opened for trading late in 2023 and will continue through 2024 and 2025. Learnings from this project will inform us about many aspects of how we view distribution and delivery of electricity going forward.

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[3] Annual Planning Outlook, IESO 2020 and 2022

[4] Windsor-Essex Regional Planning and IRRP (Integrated Regional Resource Plan), IESO 2019-2023

[5] Ibid.

Cost efficiency was realized through the ongoing use of digital tools and smart network planning and investment decisions. Of note is the work conducted to implement self-healing grid technology, mainly in the form of smart devices like reclosers and a real-time automation controller in the distribution system. This will enable safer operation of the system and improve restoration time from outages, and resource efficiency. In addition, to further the digitization process and realize process efficiencies, EPLC has set the framework for developing digital job packages, which includes electronic scheduling of disconnects and reconnects for the metering department. The digitization of job packages will continue in 2024 and 2025.

In 2023, there was additional focus on advancing Essex Powerlines' advanced cybersecurity framework to ensure the risk of cyber attacks are mitigated. In addition, the EPLC team created an Incident Response Plan (IRP) and ran through various scenarios of cyber-attacks and the proper procedures and responses to combat such attacks.

EPLC invested in its human resource capital plan in 2023, with more realignment opportunities planned for 2024 and 2025. Realignment and additions to the metering and operations department occurred to ensure successful succession planning in the coming years. In addition, EPLC's main office on Highway #3 has undergone major renovations to accommodate the growing needs of the organization. The renovations were sought to construct a more inclusive and open working space for each department and better utilize the space to keep up with the growth of the organization.

EPLC continued its involvement with the St. Clair Powerline Apprenticeship program in 2023 by once again, providing summer employment for 2 first year powerline students. In addition, both the Manager of Corporate Services and Line Supervisor at EPLC sit on St. Clair College's Powerline Advisory Committee. The committee works to review and recommend any changes to the powerline program outline, syllabus, and curriculum based on trends in the sector, as well as share industry knowledge based on hiring trends and best practices. This is just one way that EPLC invests in the youth in its community to help support the future of the industry.

2024-2025 Strategic Goals & Alignment with Cost of Service

Essex Powerlines continues to focus on its path to digital transformation to keep pace with, and be leaders in, the ever-evolving industry. The 2024-2025 business plan was commissioned in parallel with the Cost-of-Service Application and takes into consideration the need to evolve from a traditional poles-and-wires company into an Energy Service Enablement company. Details of specific initiatives outlined in the Cost-of-Service Application are summarized below as the main initiatives that EPLC plans to undertake to achieve their strategy:

1. Expand Control Room Collaborative Work
    a. Broaden the use of the SmartMAP implementation and leverage its improved capabilities in coordination with control room activities. With new functionality that can detect electric vehicles, SmartMAP continues to be an important tool in the evolution of EPLC's distribution system;
    b. Realize synergies and costs designed into this Application in the area of control room and how a control room can be leveraged to recognize and optimize available local flexibility of supply;
    c. Expedite responses to, and recovery from, unplanned and/or severe weather events that are increasing in frequency and severity.

2. Invest in Automation
    a. Customer communication automation to improve the overall customer experience and timeliness of interactions;
    b. Process automation to reduce (with the goal to eliminate) manual processes across multiple departments so that resource efforts can be focused on modernization in essential areas of distribution system planning and operation. The outcome here is a real-time distribution system and energy management planning process which is achieved in the follow phases:
        1. Automation of existing DSP process
        2. Map-based design estimating
        3. Digital Work Packages
        4. Ongoing load forecasting - critical in light of electrification forecast and known constraints in the province and in Windsor-Essex region specifically.
3. Invest in Technology
    a. Invest in AMI 2.0 and self-healing grid devices; leveraging advanced technology to improve reliability, reduce outage duration, and protect assets.
    b. Invest in systems and software that permit ongoing improvements to distribution system analytics - short-, mid- and long-term benefits, such as, outage management, distribution system planning and prioritization, condition-based asset planning.
4. Continue to integrate the DSO pilot into the rates and operating activities of EPLC.

EPLC's proactive plans and initiatives to further its goal of becoming an Energy Services Enablement company is aligned with the strategic direction outlined in the 2023 Letter of Direction published by the Ministry of Energy (attached to this Business Plan). The letter written by Minister of Energy, Todd Smith, and addressed to the Ontario Energy Board, includes updates on the government's priorities for the sector at large. These priorities include, but are not limited to, advancing the Powering Ontario's Growth plan which outlines the provinces' actions to drive economic growth and electrification through the 2030s and 2040s, facilitating innovation within Ontario's Regulatory Framework, including Distributed Energy Resources as a necessity for a clean energy economy and utilizing these resources to help consumers manage energy costs and capitalize on investments, and removing regulatory barriers by reviewing OEB processes and finding efficiencies to reduce regulatory burden on utilities, among other paramount initiatives. In all, EPLC's business plan and Cost-of-Service Application reflect the overarching goals and objectives of transforming into a Distribution System Operator, investing in technology that provides real-time data for distribution system planning, and automating processes to enable consumer choice and electrification, which align directly with the Government's energy transition priorities.

Distribution System Plan (DSP)

The existing 5-year DSP was formulated as part of the 2018 Cost-of-Service Application and outlined plans for 2018-2022. As EPLC continues to work on the 2025 Cost-of-Service Application, spending for 2023 and 2024 has been planned to match pace with the previous DSP. The 2024 budget plan and associated analysis is outlined below. It is important that the budget be prepared in line with the DSP to ensure actuals match pace with the plan as outlined. This is necessary to permit the achievement of prudent spending alongside timely achievement of work programs and projects.

The 2025 Cost-of-Service Application will reflect updates to planned initiatives, work programs and projects after proper itemization, prioritization and analysis based on numerous factors. These factors include anticipated growth, required system maintenance, and reflection on achievement of the previous DSP. Below is the planned vs. actual for the last year of our DSP (2023) and the following two bridge years before our next DSP (2025-2029). 2023 Year to date is to November 15.

DSP Capital - System Access, Renewal and Service	**2022**			**2023**			**2024**		
Appendix 2 AB Table 2 - Capital Expenditure Summary fro	DSP	Budget	Actual	DSP	Budget	Year to Date	DSP	Plan	Actual
System Access	**$ 1,834,882**	**$ 1,835,324**	**$ 2,846,616**	**$ -**	**$ 2,169,928**	**$ 3,070,517**	**$ -**	**$ 2,456,726**	**$ -**
Subdivisions	$ 402,011	$ 996,367	$ 1,587,896	$ -	$ 1,013,700	$ 1,911,516	$ -	$ 1,054,248	$ -
Residential Connections/Expansion	$ 414,485	$ 414,477	$ 484,969	$ -	$ 531,000	$ 627,350	$ -	$ 552,240	$ -
Municipal Requests	$ 643,218	$ 48,983	$ 371,804	$ -	$ 200,000	$ 141,578	$ -	$ 208,000	$ -
New Service Upgrades - C & I (includes expans	$ 375,168	$ 375,497	$ 401,947	$ -	$ 425,228	$ 390,073	$ -	$ 642,238	$ -
System Renewal	**$ 2,194,753**	**$ 2,637,367**	**$ 2,611,154**	**$ -**	**$ 2,897,404**	**$ 2,127,923**	**$ -**	**$ 2,875,242**	**$ -**
Pole Replacement Program	$ 354,997	$ 592,870	$ 652,193	$ -	$ 742,989	$ 614,326	$ -	$ 194,934	$ -
Overhead Reactive Replacements	$ 85,379	$ 85,379	$ 79,825	$ -	$ 123,552	$ 119,916	$ -	$ 128,494	$ -
Underground Reactive Replacements	$ 67,313	$ 67,312	$ 237,850	$ -	$ 97,408	$ 97,095	$ -	$ 101,304	$ -
Install/Replace Load Breaks	$ 62,094	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Infrastructure Rebuild Program (OH and UG)	$ 1,329,416	$ 1,508,388	$ 1,413,742	$ -	$ 1,568,724	$ 1,067,584	$ -	$ 1,600,098	$ -
Switchgear Replacement Program	$ 79,732	$ -	$ -	$ -	$ -	$ 921	$ -	$ -	$ -
Metering Upgrades & Replacement Program (M	$ 172,310	$ 325,116	$ 190,002	$ -	$ 304,097	$ 200,111	$ -	$ 787,353	$ -
OVERHEAD unresolved PM/IR/Smart Map - O	$ 7,766	$ 10,368	$ -	$ -	$ 10,783	$ -	$ -	$ 11,214	$ -
UNDERGROUND unresolved PM/IR/Smart Ma	$ 8,797	$ 20,983	$ -	$ -	$ 21,823	$ -	$ -	$ 22,695	$ -
Misc Capital Costs Job 0203	$ 26,950	$ 26,950	$ 37,542	$ -	$ 28,028	$ 27,969	$ -	$ 29,150	$ -
System Service	**$ 1,341,797**	**$ 780,675**	**$ 759,637**	**$ -**	**$ 1,817,039**	**$ 1,186,709**	**$ -**	**$ 2,615,155**	**$ -**
Purchase/Sell HONI Leamington Assets		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Malden TS 2X new feeder & Reconfiguration	$ 377,802	$ -	$ -	$ -	$ 100,000	$ -	$ -	$ -	$ -
Generation Connections (Total of > 10kW and	$ 51,818		$ 3,869	$ -	$ 24,900	$ 18,490	$ -	$ 25,896	$ -
Purchase/Sell HONI LaSalle Assets	$ 512,317	$ -	$ -	$ -	$ -	$ -	$ -	$ 700,000	$ -
Reclosers (SH Grid)	$ 399,861	$ 386,675	$ 317,404	$ -	$ 817,131	$ 747,017	$ -	$ 1,060,505	$ -
Leamington TS		$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Control Room Capital Costs		$ -	$ -	$ -	$ 60,000	$ -	$ -	$ 61,200	$ -
SHG FLISR ADMS		$ 274,000	$ 297,746	$ -	$ 100,000	$ 3,492	$ -	$ 102,000	$ -
Operations & Engineering Manager's Time		$ 120,000	$ 140,619	$ -	$ 195,000	$ 181,856	$ -	$ 248,900	$ -
DSO Activities		$ -	$ -	$ -	$ 520,008	$ 235,854	$ -	$ 416,654	$ -
TOTAL EXPENDITURE	**$ 5,371,432**	$ 5,253,366	$ 6,217,408	**$ -**	$ 6,884,371	$ 6,385,148	**$ -**	$ 7,947,123	$ -

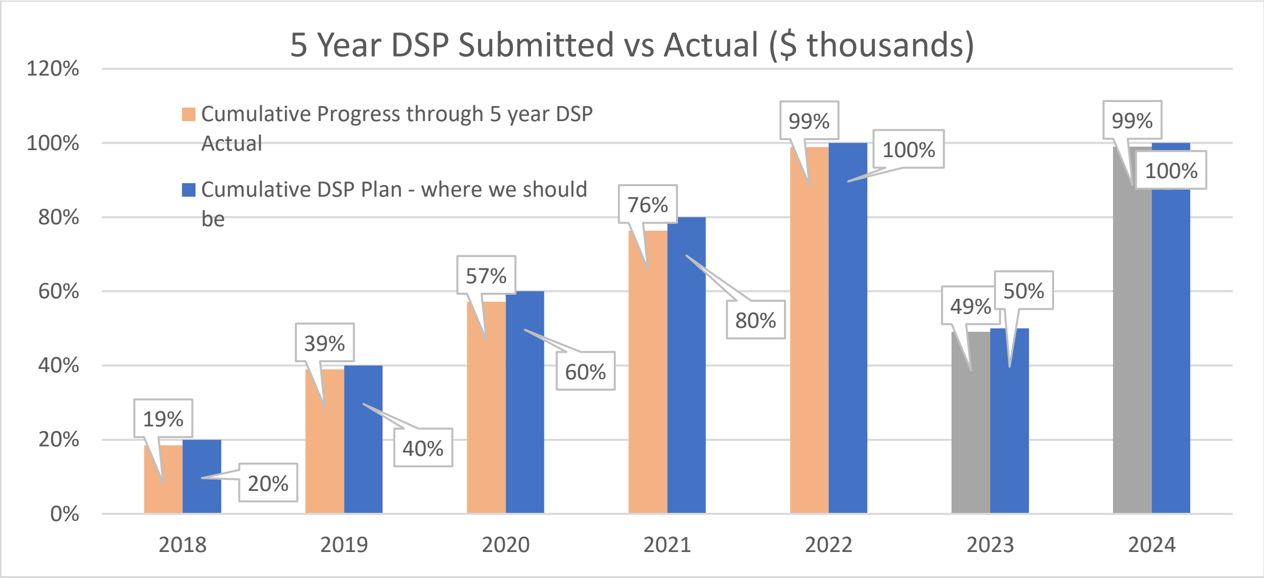
Capital Spending

For the 2018-2022 DSP, significant dollars were allocated to the purchase of HONI assets, as well as the expansion of the Malden TS. HONI has indicated that the Malden TS is at capacity (no additional room for more breakers) and during this time HONI refused to sell any assets. These funds were moved from System Service and distributed to System Access and System Renewal. We could not anticipate the volume of developments that have been presented from 2021 onward. Our original estimate of 300 connections was exceeded by more than 250%. The extensive growth can be attributed to the More Homes Built Faster Act (Bill 23) passed by the Ontario government, as well as the development of the NextStar Energy EV Battery Manufacturing Plant. For 2023, we are seeing developments slowing, likely due to rising interest rates and significant material cost increases. The expectation for 2024 and 2025 is that developments will remain at a slightly reduced pace than 2022/2023, unless the interest rates fall. If necessary, EPLC is prepared to make whatever accommodations are needed to support growth.

A new category, called DSO Activities, highlights the additional costs to incorporate EPLC's transition to a Distribution System Operator (DSO). It is important to note that monetizing this transition is still in the investigation stage. Even though the OEB has provided direction that these costs fall under distribution activities and can be captured in rates, the debate as to who the beneficiary is and who should ultimately pay is not fully understood.

In conjunction with the DSO activities, EPLC's Self-Healing Grid/Recloser investments increased due to the NRCan SREP funding project awarded to EPLC. This funding is set to terminate in March of 2025.

Shown below is EPLC's performance for the previous DSP (2018-2022) and the projected spend for the bridge years of 2023 and 2024 ahead of our next Cost-of-Service/DSP for 2025 to 2029.



As noted previously, EPLC has seen unprecedented growth in the Residential & Commercial/Industrial sectors for all our serviced communities. Listed below are projects currently under construction and known developments that EPLC is working on. It is important to note that many preliminary projects are not listed here as dates have not yet been defined for construction to begin, or because they are still in the early stages of design.

ESSEX POWERLINES CORPORATION

Residential Expansion

Customer Capital (under Construction)
AMHERSTBURG
AM 247 Brock St – Phase 1 – 16-unit condo + HS + Building 2 x1 Bulk meter 34 unit
AM 207 Brock St – 74 unit- 4 story apartment building
AM 225 Sandwich St. S – Riverview Apartments -Piroli – Ph 2 – 114-unit building
LASALLE
LA Edgemore Townhomes serv
LA 1730 Sprucewood LA Suites (2 buildings) Lefaive – (2023 – 36 + 4 com, 38 + 4 com)
LA Martin Lane West Subdivision 142 Lots (60 SF & 41 SD)
LA Laurier Horizons Ph1 & Ph2 (x2 60-unit Bldgs., x2 48-unit Bldgs., x4 5-unit 2-story Villas)
TECUMSEH
TE 1429,1415,1401 Lesperance Townhomes – 3 Buildings with 6 units each
Future Development
AMHERSTBURG
AM Rocksedge Ph2 – 241 Units (Total of 355 units)
AM 359 Dalhousie – 12-unit, 4 storey building w/detached parking garage.
AM 365 Sandwich St. South, 77 units, 6 storey building.
AM RC SPENCER – Mulberry Court 26 semi-detached (52 units)
AM HRK Realty INC – 22 SF, East of King St.
LASALLE
LA Huron Acres (AMICO) 6SF and 18SD
LA 2708617 Ontario Ltd 5881 Malden Condo 2 building 45 units each plus 2 HS
LA Tenth St Residential Development (1SF and 11 SD)
LA Horizon City and LaSalle Triangle Developments- N of Laurier Pkwy & W of Huron Church Rd)
LA 1826 Wyoming Condos Building A (6-storey, 66 units) and Building B (5-storey, 38 units)
LA 1780 Sixth Concession Development (47 SF, 22 attached, and 1 commercial)
LEAMINGTON
LE Parkdale Condos 2 buildings 54 unit each plus 2 House Services
LE 111 Erie St 36-unit apartment plus HS
LE 111 Sherk St – 4 x 72 unit building plus 1st floor mixed use (7 storey)
LE 389 Erie St South Comm/Res. Development (10 floors X 6 residential 1 restaurant, and 5 retail)
LE South of Bruce Ave. – 2 storey multi unit Residential
LE 26 Robson Rd – 4 Storey-24unit Apartment Building
LE 151 Robson Rd. – 4-storey (40 unit) Multi-Unit Residential
LE Ellison Ave. Coco Development Ph 1 of 5 (PH1 consists of x4 4 -Plex, x4 5-Plex, x5 6-Plex units)

TECUMSEH
TE Victoria By the Lake Residential (54 Meters) – x8 Res. Build. (52 meters) +Garage with EV Chargers (2 Meters)

Commercial, Institutional, Industrial Expansion

Customer Capital (under Construction)
AMHERSTBURG
AM 131&135 Sandwich St. South – HARVEYS and multi unit Comm. Building
LASALLE
LA 6400 Milford – Pump Station Upgrade w/New 3PH TX
LA 2794 Front Road – Facca Marina Service Upgrade w/New Transformer
TECUMSEH
TE 13800 Tecumseh Rd. East – Northshore School
Future Development
AMHERSTBURG
AM 7 Fryer Street – 6 commercial + 6 Residential
AM 527 Sandwich St, South. – x3 Drive through restaurants with 1 retail building in the rear
AM 256 Dalhousie St. Hotel – 5 Story, 84 rooms
LASALLE
LA 6150 Malden Rd – 3 storey hotel w/Restaurant and Commercial
LEAMINGTON
LE 125 Talbot St W – Mixed Use Comm./Residential
LE 320 Erie St. South Mixed Use Development – x2 Commercial (WFCU & Restaurant) + Hotel (85 rooms)
LE Caldwell First Nation Development – Mixed Use Res./Commercial
TECUMSEH
2023 to 2024 Future Generation
LA 99 kW Net Metering site1900 6th Concession
LA 330 Bouffard 10kW NM Solar
LA 1225 Ashberry 10kW NM Solar Application Stage
LE 103 Erie 60kW NM Solar. Payment Received for CIA study
LA 1687 Winfield 10kW NM Solar Application Stage

Municipal Road Projects

Below is a list of known Municipal Road Projects:

- LA Howard/Bouffard Master Drainage Study
- LA Reaume/Bouffard Rd Watermain Replacements
- LA Malden Rd Improvements
- TE 14080 Riverside Dr. East - PJ Cecile Pump Upgrade
- TE Tecumseh Rd. CIP – likely to continue '24 or '25
- LE Erie St. Streetlighting
- LE Leamington Streetscaping Project

Multi-use trail development and some infrastructure/road upgrades are expected – timing will be based on available municipal funding and government grants. The Tecumseh CIP execution has started with the VIA rail regarding the addition of infrastructure in preparation for moving the electrical underground. There should be little-to-no cost of this rework to EPLC. Interpretation of the (Public Service Works on Highways Act) will be key in establishing agreements with our municipal shareholders.

Most municipal projects will be streetlights, metered plugs, and traffic light connections. Municipal work is estimated at $208 000.

Finance and Regulatory Department

In 2024, EPLC will be developing a Real-Time DSP and Regulatory Management Tool. EPLC is actively seeking additional funds to contribute to the development of the tool.

CIS/Billing Department

With the evolution of the utility sector, traditional CIS applications used to manage customer data and billing is no longer sufficient. EPLC plans to invest in a flexible modern CIS system to match system needs and enhance the consumer experience.

Utility Collaboration – Unification Strategy

EPLC has the goal of expanding collaboration with similar, like-minded utilities. Opportunities for collaboration include the following topics:

- SCADA
- Control Room Services
- Health and Safety
- Engineering
- Regulatory
- IT and OT services

Currently EPLC is collaborating with Welland Hydro in several ways. By leveraging EPLC's SmartMAP, Welland has integrated full SCADA functionality and entered an agreement to provide control room services to EPLC. Welland Hydro has expertise specifically in SCADA and transmission engineering that is not a strength of EPLC staff and as such EPLC also has been including Welland in discussions with the IESO's Transmission-Distribution Working Group, with the aim of enhancing internal EPLC knowledge and further developing competence as EPLC explores needs in the area of Tx/Dx.

Similarly, in support of Welland and potentially other LDC's, EPLC could provide engineering services where there is an identified need. This permits strong cross-collaboration and enables continued progress while making the best use of available resources. In 2023, the expectation would be that EPLC extends their expertise on Health and Safety policies and procedures and enables Welland Hydro to streamline those processes.

Fleet

After completing an in-house EV fleet feasibility study in 2022, it was determined that our fleet could add Hybrid and EV's under certain vehicle classes. Based on vehicle life cycle, we started down the path of adding hybrid vehicles. Our fleet currently includes two hybrid vehicles with plans to continue to add either hybrid or EV's. Additional EV studies will be conducted in the coming years to confirm the approach and that we are in line with what our sector fleet requirements can allow for.

2023

- Replacement of Unit 107 (2011 Posi Plus 100-46, 46' bucket with material handler) with similar unit, unit is at end of life.
- Replacement of Unit 112 (2014 Ford F550 Dump) with similar unit, unit is at end of life (NOTE: Due to Ford fleet ordering constraints, our order for 2023 was not picked up by factory, this order will be pushed to 2024)
- Purchase of additional vehicle for engineering (Unit 88 – 2022 Chev Colorado)

2024

- Replacement of Unit 112 (2014 Ford F550 Dump) with similar unit, unit is at end of life (carried from 2023)
- Replacement of metering vans Unit 74 and 75 (2016 Dodge Promasters) with (2) Ford F150 chassis (or similar) and contractor cap, units will be at end of life.
- Replacement of Unit 76 (2016 Chev Silverado 2500) with Ford F150 (or similar), unit will be at end of life.
- Replacement of Unit 108 (2012 Posi-Plus 100-42, 42' bucket service unit) with similar unit, unit will be at end of life.

2025

- Replacement of Unit 77 (2017 Chev Silverado) with similar unit, unit will be at end of life.
- Replacement of Unit 80 (2017 GMC Sierra 1500) with similar unit, unit will be at end of life.
- Replacement of Unit 110 (2013 50' Terex Commander PG 5050 RBD) with similar unit, unit will be at end of life.
- Replacement of unit 736 (pole trailer) with similar unit, unit will be at end of life.

Human Resources

Midway through 2023, we added support to the SCADA commissioning project with an EIT Distribution Engineer. In the 4th quarter of 2023, a new General Manager was appointed, and some realignment was undertaken to optimize the organization's structure. Specifically, a position for a Manager of Corporate Services was created to allow appropriate focus on activities related to Health & Safety, Purchasing and Fleet.

The Regulatory Accounting Analyst hired in mid-2023 was not a suitable fit for the position, so the hiring process was restarted. It is anticipated that a new Regulatory Accounting Analyst will be hired and onboarded prior to the start of 2024.

For 2024, the plan is to continue to implement elements of the organizations resource optimization plan. This re-alignment includes the addition of a Purchasing Supervisor and a Director of Customer Experience. Additionally, a dedicated Manager of Technology & Digital Experience position was proposed to back fill the Director of Technology, and that position will be filled in early 2024.

Going into 2025, the plan would be to bring on an additional powerline apprentice to continue to develop and cover attrition.

The Collective Agreement for EPLC expires in March 2024. Planning for negotiations is underway and forecast changes in compensation are budgeted accordingly in 2024 and beyond.

Other HR initiatives are ongoing with the continuation of the wellness committee (comprised of both union and management employees) and the fitness reimbursement program. EPLC remains committed to employee well-being and will continue to bring programs to promote wellness in the work environment.

Upcoming retirements:

It is anticipated we will lose 1-2 Distribution Design Technologists in 2024. We already have staff in place to backfill those retirements.

Health & Safety

In 2023, year-to date, incident data is summarized as:

(2) Near Misses –

- 3rd party electrician pulled EPL meter exposing energized meter socket.
- 3rd party excavating contractor struck secondary service while digging foundation causing flashover and damage to EPL transformer/secondary cable.

(2) Vehicle/Equipment –

- Employee struck cement saw with unit 116 causing damage to saw.
- Employee struck from behind while stopped in unit 107 in construction zone on Highway 3 in Town of Essex

(6) Accident –

- Employee strained shoulder while pulling up secondary service during ice storm (first aid only)
- Employee strained their groin while working aloft installing recloser unit (has resulted in modified duties since June 12 and is schedule for surgery March 2024)
- Employee strained back while clearing tree from OH lines during summer storm (medical aid only)
- Employee stung by wasps multiple times while stringing in streetlight duplex (first aid only)
- Employee struck with secondary rack that fell from bucket tray that was knocked off when secondary service slipped off secondary rack on pole (first aid only)
- Employee stung by wasp while in boardroom (medical aid only)

Health & Safety Training initiatives for 2024 continue as usual and will include:

- WHMIS/GHS (companywide)
- CPR/Defib (companywide)
- Defensive Driving (Lines, Utility, Metering, Eng)
- ARZ Licensing (Lines)
- Chainsaw Training (Lines/Utility)
- Candura Training (Metering)
- Pole Top/Bucket Rescue (Lines/Utility)
- Utility Work Protection Recertification (Lines/Metering)

Regulatory Outlook

In October of 2023, EPLC filed its annual IRM application, for rates effective May 1, 2024. EPLC is seeking a residential rate class increase of 5.5%, which can be attributed, for the most part, to the notably high inflation factor that was published for inclusion in rates at 4.8%.

EPLC also moved during 2023 from Group 2 to Group 1 in the tranche assignments of efficiency ratings (based on the PEG econometric model that the OEB employs). This means that EPLC is assigned a stretch factor of zero for offset against the inflationary factor in the IRM model.

As previously noted, the IRM is requesting rates effective May 1, 2024, and these rates will be effective for a period of 8 months as EPLC is required to file their Cost-of-Service Application in April of 2024, seeking rebasing effective January 1, 2025. The Cost-of-Service process in fully underway.

2023 Forecast 2024 Budget Highlights

Attached are the income statement, balance sheet, cash flow statement and statement of retained earnings for Essex Powerlines Corporation for the 2023 forecasted and 2024 budget years. Please note that 2025 and 2026 budget numbers will be forthcoming in early 2024 and will be formulated to include inputs of the upcoming 2025 Cost of Service rebasing application.

Attachment 1-B

Executive Certification

ESSEX POWERLINES CORPORATION

Re: Certification of Evidence

I, Jayna Sweeney, Vice President, Finance and Strategy, hereby make the following certifications regarding the information filed in the Essex Powerlines Corporation's (EPLC's)) 2025 Cost of Service Electricity Distribution Rate Application and any evidence filed in support of
the application:

1. I certify that the information filed does not include any personal information (as that phrase is defined in the Freedom of Information and Protection of Privacy Act) unless it is filed in accordance with Rule 9A of the OEB's Rules (and the Practice Direction, as applicable) in accordance with Chapter 1 of the Filing Requirements for Electricity Distribution Rate Applications – 2022 Edition for 2023 Rate Applications issued April 18, 2022.

2. I certify that the information filed by EPLC in this Application is accurate, consistent, and complete to the best of my knowledge in accordance with Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications issued December 15, 2022.

3. I certify that EPLC has robust processes and internal controls in place for the preparation, review, verification and oversight of the deferral and variance account balances being disposed in accordance with Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications – 2023 Edition for 2024 Rate Applications issued December 15, 2022.

JSweeney

April 30, 2024

Jayna Sweeney
Vice President, Finance and Strategy

Date

Attachment 1-C

OEB 2022 Scorecard

Performance Outcomes	Performance Category	Performance Year	2018	2019	2020	2021	2022
CUSTOMER FOCUS	Service Quality	New Residential/Small Business Services Connected on Time (Target: 90%)	91.18%	94.78%	93.27%	90.84%	91.45%
		Scheduled Appointments Met on Time (Target: 90%)	94.79%	93.15%	94.46%	93.15%	98.68%
		Telephone Calls Answered on Time (Target: 65%)	87.67%	82.62%	65.17%	76.62%	80.94%
	Customer Satisfaction	Billing Accuracy (Target: 98%)	98	100	99.92	99.95	99.95
		First Contact Resolution	98.52%	98.99%	99.15%	99.08%	99.60%
		Customer Satisfaction Survey Results	83%	83%	86%	86%	86%
OPERATIONAL EFFECTIVENESS	Safety	Level of Public Awareness			83%	85%	85%
		Level of Compliance with Ontario Regulation 22/04 (Target: substantially compliant)	C	C	C	C	C
		Number of General Public Incidents	0	0	0	0	0
		Rate per 10, 100, 1000 km of line	0	0	0	0	0
	System Reliability	Average Number of Times Power to Customer is Interrupted	1.29	0.84	0.95	0.89	0.84
		Average Number of Hours Power to Customer is Interrupted	1.82	1.27	1.23	2.02	1.82
	Asset Management	Distribution System Plan Implementation on Progress	18.80%	37.50%	57	76.13%	97.65%
	Cost Control	Efficiency Assessment (1 = most efficient 5 = least efficient)	2	2	2	2	1
		Total Cost ($) per Customer	578	580	577	564	625
		Total Cost ($) per Km of Line	37960	10907	10979	10789	12005
PUBLIC POLICY RESPONSIVENESS	Connection of Renewable Generation	Renewable Generation Connection Impact Assessments Completed on Time			100%		
		New Micro-Embedded Generation Facilities Connected on Time (Target: 90%)	100	100			100
FINANCIAL PERFORMANCE	Financial Ratios	Liquidity: Current Ratio	0.67	0.57	0.72	0.76	0.86
		Leverage: Total Debt to Equity Ratio	1.1	1.31	1.32	1.25	1.27
		Profitability: Regulatory Return on Equity - Deemed	9.00%	9.00%	9.00%	9.00%	9.00%
		Profitability: Regulatory Return on Equity - Achieved	8.11%	7.30%	6.14%	6.79%	6.09%

Attachment 1-D

EPLC 2021 Audited Financial Statements

Financial Statements of

ESSEX POWERLINES CORPORATION

And Independent Auditors' Report thereon

Year ended December 31, 2021
(Expressed in thousands of dollars)

KPMG LLP
618 Greenwood Centre
3200 Deziel Drive
Windsor ON N8W 5K8
Canada
Tel 519-251-3500
Fax 519-251-3530

INDEPENDENT AUDITORS' REPORT

To the Shareholder of Essex Powerlines Corporation

Opinion

We have audited the financial statements of Essex Powerlines Corporation (the "Entity"), which comprise:

- the statement of financial position as at December 31, 2021
- the statement of comprehensive income for the year then ended
- the statement of changes in 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 Entity 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 Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled are other ethical 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 International Financial Reporting Standards, 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 Entity'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 Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity'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 Entity'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 Entity'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 Entity 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 represent 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

Windsor, Canada
April 25, 2022

ESSEX POWERLINES CORPORATION

Statement of Financial Position
As at December 31, 2021, with comparative information for 2020
(in thousands of dollars)

	Note	2021	2020
Assets			
Current assets			
Cash and cash equivalents		$ 920	$ 1,049
Accounts receivable	4	5,904	6,437
Unbilled revenue		5,710	6,111
Income taxes receivable		-	256
Materials and supplies	5	955	621
Prepaid expenses		132	108
Total current assets		13,621	14,582
Non-current assets			
Property, plant and equipment	6	68,384	66,291
Intangible assets	7	960	935
Total non-current assets		69,344	67,226
Total assets		82,965	81,808
Regulatory balances	9	14,119	15,181
Total assets and regulatory balances		$ 97,084	$ 96,989

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Financial Position
As at December 31, 2021, with comparative information for 2020
(in thousands of dollars)

	Note	2021	2020
Liabilities			
Current liabilities			
Bank indebtedness		$ -	$ 1,081
Accounts payable and accrued liabilities	10	10,177	12,099
Long-term debt due within one year	11	5,418	5,323
Income taxes payable		353	-
Sub debt payable – shareholder		-	374
Customer deposits		1,258	993
Dividend payable		1,068	1,244
Total current liabilities		18,274	21,114
Non-current liabilities			
Long-term debt	11	32,828	31,316
Post-employment benefits	12	2,674	2,844
Deferred revenue		7,181	6,165
Deferred tax liabilities	8	2,450	2,238
Total non-current liabilities		45,133	42,563
Total liabilities		63,407	63,677
Equity			
Share capital	13	15,773	15,773
Solar equity reserve (appropriation of retained earnings)		-	374
Retained earnings		13,251	11,425
Accumulated other comprehensive income		1,485	1,373
Total equity		30,509	28,945
Total liabilities and equity		93,916	92,622
Regulatory balances	9	3,168	4,367
Total liabilities, equity and regulatory balances		$ 97,084	$ 96,989

See accompanying notes to the financial statements.

On behalf of the Board:

_______________ Director

William Wear Director

ESSEX POWERLINES CORPORATION

Statement of Comprehensive Income
Year ended December 31, 2021, with comparative information for 2020
(in thousands of dollars)

	Note	2021	2020
Revenue			
Sale of energy		$ 69,438	$ 77,342
Distribution revenue		14,864	13,161
Solar generation		26	383
Other		1,485	1,248
	14	85,813	92,134
Operating expenses			
Cost of power purchased		70,767	78,745
Operating expenses	15	7,859	8,188
Solar expenses		7	54
Depreciation and amortization		3,061	2,997
Research and development SR&ED ITC received		(18)	(12)
Employee future benefits-plan improvements		-	368
		81,676	90,340
Income from operating activities		4,137	1,794
Net finance costs	16	(1,123)	(1,117)
Income before income taxes		3,014	677
Current tax expense	8	460	67
Deferred tax expense	8	171	51
Net income for the year		2,383	559
Net movement in regulatory balances, net of tax	9	137	1,424
Net income for the year and net movement in regulatory balances		2,520	1,983
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Re-measurements of post-employment benefits	12	152	274
Tax on re-measurements		(40)	23
Other comprehensive income for the year		112	297
Total comprehensive income for the year		$ 2,632	$ 2,280

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Changes in Equity

Year ended December 31, 2021, with comparative information for 2020

(in thousands of dollars)

	Share capital	Solar Equity	Retained earnings	Accumulated other comprehensive income (Loss)	Total
Balance at January 1, 2020	$ 15,773	$ 374	$ 10,686	$ 1,076	$ 27,909
Net income and net movement in regulatory balances	-	-	1,983	-	1,983
Other comprehensive income	-	-	-	297	297
Dividends	-	-	(1,244)	-	(1,244)
Balance at December 31, 2020	$ 15,773	$ 374	$ 11,425	$ 1,373	$ 28,945
Balance at January 1, 2021	$ 15,773	$ 374	$ 11,425	$ 1,373	$ 28,945
Net income and net movement in regulatory balances	-	-	2,520	-	2,520
Other comprehensive income	-	-	-	112	112
Appropriation of retained earnings to solar equity reserve (reversed)	-	(374)	374	-	-
Dividends	-	-	(1,068)	-	(1,068)
Balance at December 31, 2021	$ 15,773	$ -	$ 13,251	$ 1,485	$ 30,509

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Cash Flows
Year ended December 31, 2021, with comparative information for 2020
(in thousands of dollars)

	2021	2020
Operating activities		
Net Income and net movement in regulatory balances	$ 2,520	$ 1,983
Adjustments for:		
Depreciation and amortization	3,061	2,997
Amortization of deferred revenue	(185)	(161)
Post-employment benefits	(18)	386
Net loss on disposal of property, plant and equipment	82	25
Decrease in deferred charges	-	71
Net finance costs	1,123	1,117
Income tax expense	631	118
	7,214	6,536
Change in non-cash operating working capital:		
Accounts receivable	533	147
Unbilled revenue	401	(309)
Materials and supplies	(334)	(8)
Customer deposits	265	(248)
Prepaid expenses	(23)	27
Accounts payable and accrued liabilities	(1,922)	1,374
	(1,080)	983
Net movement in regulatory balances	(137)	(1,424)
Income tax received (paid)	149	(32)
Interest paid	(1,133)	(1,137)
Interest received	10	20
Net cash from operating activities	5,023	4,946
Investing activities		
Purchase of property, plant and equipment	(6,610)	(5,602)
Purchase of intangible assets	(249)	(293)
Proceeds on disposal of property, plant and equipment	1,598	8
Contributions received from customers	1,201	652
Net cash used by investing activities	(4,060)	(5,235)
Financing activities		
Dividends paid	(1,244)	(1,244)
Proceeds from long-term debt	4,000	11,156
Repayment of long-term debt	(2,393)	(6,487)
Repayment of sub-debt payable – shareholder	(374)	-
Net cash from financing activities	(11)	3,425
Change in cash, cash equivalents and bank indebtedness	952	3,136
Cash and cash equivalents and bank indebtedness, beginning of year	(32)	(3,168)
Cash, cash equivalents and bank indebtedness, end of year	$ 920	$ (32)

See accompanying notes to the financial statements.

1. Reporting entity:

Essex Powerlines Corporation (the "Corporation") is a rate regulated, municipally owned local distribution company ("LDC") which is wholly owned by Essex Power Corporation, which in turn, is wholly owned by the shareholders of Essex Power Corporation including the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The Corporation was incorporated on April 18, 2000 under the *Business Corporations Act* (Ontario), in accordance with the *Electricity Act*. The Corporation is located in Oldcastle, Ontario. The address of the Corporation's registered office is 2730 Highway 3, Oldcastle, ON N0R 1L0.

The Corporation delivers electricity and related energy services to residential and commercial customers in Amherstburg, LaSalle, Leamington and Tecumseh, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB and adjustments to the Corporation's distribution and power rates require OEB approval.

The financial statements are for the Corporation as at and for the year ended December 31, 2021.

2. Basis of presentation:

(a) Statement of compliance:

The Corporation's financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 25, 2022.

(b) Basis of measurement:

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

(d) Use of estimates and judgments:

(i) Assumptions and estimation uncertainty:

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 years affected.

2. Basis of presentation (continued):

(d) Use of estimates and judgments (continued):

(i) Assumptions and estimation uncertainty (continued):

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

(i) Notes 3 (d), (e), (f), 6, 7 – estimation of useful lives of its property, plant and equipment and intangible assets and related impairment tests on long-lived assets
(ii) Notes 3 (i), 9 – recognition and measurement of regulatory balances
(iii) Notes 3 (j), 12 – measurement of defined benefit obligations: key actuarial assumptions
(iv) Notes 3 (h), 17 – recognition and measurement of provisions and contingencies

(ii) Judgments:

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following note:

(i) Note 3 (k) – leases: whether an arrangement contains a lease

(ii) Note 3 (b) – determination of the performance obligation for contributions from customers and the related amortization period

(iii) Notes 3(i), 9 – recognition of regulatory balances

(e) Rate regulation:

The Corporation 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, such as the Corporation, 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 LDC's 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 during the year to June 2, 2021.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

Rate setting

(i) Distribution Rates:

The Corporation files a "Cost of Service" ("COS") rate application every five years, unless approved for a deferral, under which the OEB establishes the revenues required to recover the forecasted operating costs, including amortization and income taxes, of providing the regulated electricity distribution service and providing a fair return on the Corporation's rate base. The Corporation 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 any registered interveners. Rates are approved based upon the review of evidence and information, including any revisions resulting from that review.

In the intervening years, an Incentive Regulation 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 set by the OEB and a "stretch factor" determined by the relative efficiency of an electricity distributor.

On August 28, 2017, the Corporation submitted a COS rate application to the OEB to change distribution rates effective May 1, 2018. The application was approved by the OEB on October 10, 2018.

On November 2, 2020, the Corporation submitted an IRM Application to the OEB requesting approval to change distribution rates effective May 1, 2021. The IRM Application, which provided a mechanistic and formulaic adjustment to distribution rates and charges, was approved by the OEB on March 25, 2021. The GDP IPI-FDD for 2021 is 2.20%, the Corporation's stretch factor is 0.15% and the productivity factor determined by the OEB is 0%, resulting in a net adjustment of 2.05% to the previous year's rates.

(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. In 2017, the OEB set new lower Regulated Price Plan (RPP) prices established under the *Ontario Fair Hydro Act, 2017*.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

(ii) Electricity Rates (continued):

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.

In 2021, the OEB also adjusted the Regulated Price Plan (RPP) prices in January and February in response to the Government issued Emergency Orders under the *Emergency Management and Civil Protection Act* to assist Ontarians who were forced to stay home due to the COVID-19 pandemic.

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) Retail Transmission Rates:

These are the costs of delivering electricity from generating stations across the Province to local distribution networks. These charges include the costs to build and maintain the transmission lines, towers and poles and operate provincial transmission systems. Retail transmission rates are passed through to the operators of transmission networks and facilities.

(iv) Wholesale Market Service Rates:

These are the costs of administering the wholesale electricity system and maintaining the reliability of the provincial grid and include the costs associated with funding Ministry of Energy conservation and renewable energy programs. The Corporation is billed for the cost of the wholesale electricity system 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 all financial liabilities 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(f).

The Corporation does not enter into derivative instruments. Hedge accounting has not been used in the preparation of these financial statements.

Cash equivalents may include short-term investments with maturities of three months or less when purchased.

(b) Revenue recognition:

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. 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 Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

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, received from developers are 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 Corporation'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 useful life of the related asset.

3. Significant accounting policies (continued):

(b) Revenue recognition (continued):

Capital contributions (continued)

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.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants and the related performance incentive payments under Conservation and Demand Management ("CDM") programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies:

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on a weighted average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

(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 date of transition to IFRS, 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 contracted services, materials and transportation costs, direct labour, borrowing costs 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 Corporation's borrowings. Qualifying assets are considered to be those that take in excess of nine months to construct.

3. Significant accounting policies (continued):

(d) Property, plant and equipment (continued):

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included 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 Corporation 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.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

	Years
Buildings	50
Distribution equipment	15 – 50
Computer hardware and equipment	5 – 10
Office equipment	10
Utility equipment and trucks	7 – 10
Solar generation	20

3. Significant accounting policies (continued):

(e) Intangible assets:

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the date of transition to IFRS, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

	Years
Computer software	5
Land rights	50

(f) Impairment:

(i) Financial assets measured at amortized cost:

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

(ii) Non-financial assets:

The carrying amounts of the Corporation's non-financial assets, other than 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.

3. Significant accounting policies (continued):

(f) Impairment (continued):

(ii) Non-financial assets (continued) :

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" or “CGU”). The recoverable amount of an asset or CGU 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.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorated basis, if applicable.

An impairment loss in respect of goodwill is not reversed. For other assets, 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 or amortization, if no impairment loss had been recognized.

For the regulated business, the carrying costs of most of the Corporation's non-financial assets are included in rate base (the aggregate of approved investment in PP&E and intangible assets, excluding construction in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital) where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

(g) Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills and deposits. Interest is paid on customer deposits. Deposits are also received for planned chargeable work. No interest is paid on these deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

3. Significant accounting policies (continued):

(h) Provisions:

A provision is recognized if, as a result of a past event, the Corporation 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.

(i) Regulatory balances:

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of recognizing regulatory balances in accordance with its previous Generally Accepted Accounting Principles ("GAAP") when it adopts IFRS. An entity is permitted to apply the requirements of this standard in its first IFRS financial statements if it conducts rate-regulated activities and recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP. IFRS 14 is effective for periods beginning on or after January 1, 2016, however, early application was permitted. The Corporation elected to apply this Standard in its first IFRS financial statements as at December 31, 2015.

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or other comprehensive income ("OCI"). When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the amounts are returned to the customer at rates approved by the OEB the amounts are recognized as a reduction of revenue.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

3. Significant accounting policies (continued):

(j) Post-employment benefits:

(i) Pension plan:

The Corporation provides a pension plan for some of its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan that provides pensions for employees of Ontario municipalities, local boards and public utilities. OMERS is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by investment earnings. To the extent that the plan finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension:

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

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.

(k) Leased assets:

At inception of a contract, the Corporation assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

3. Significant accounting policies (continued):

(k) Leased assets (continued):

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Corporation's incremental borrowing rate.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The Corporation has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Corporation recognizes the lease payments associated with these leases as an expense on a straight-line basis over the lease term.

(in thousands of dollars)

3. Significant accounting policies (continued):

(l) Finance income and finance costs:

Finance income is recognized as it accrues in profit or loss, using the effective interest method. Finance income comprises interest earned on cash and cash equivalents and dividend income.

Finance costs comprise interest expense on borrowings and bank and other interest charges. Finance costs are recognized in profit or loss unless they are capitalized as part of the cost of qualifying assets.

(m) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is 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 Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation (“OEFC”). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Payments in lieu of taxes and payments under the Tax Acts are collectively referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss 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 tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

4. Accounts receivable:

	2021	2020
Trade receivables	$ 5,440	$ 6,156
Other receivables	539	457
Billable work	51	35
Less:		
Loss allowance	(126)	(211)
	$ 5,904	$ 6,437

(in thousands of dollars)

5. Materials and supplies:

Amount written down due to obsolescence in 2021 was $88 (2020 – $nil). The amount of materials and supplies consumed by the Corporation and recognized as an expense during 2021 was $755 (2020 - $853).

6. Property, plant and equipment:

		Land and buildings		Distribution equipment		Other fixed assets		Construction in-Progress		Total
Cost										
Balance at January 1, 2021	$	2,718	$	71,208	$	7,580	$	281	$	81,787
Additions		280		5,334		637		359		6,610
Disposals/retirements		-		(98)		(2,559)		-		(2,657)
Balance at December 31, 2021	$	2,998	$	76,444	$	5,658	$	640	$	85,740
Balance at January 1, 2020	$	2,685	$	66,354	$	6,940	$	278	$	76,257
Additions		33		4,921		645		3		5,602
Disposals/retirements		-		(67)		(5)		-		(72)
Balance at December 31, 2020	$	2,718	$	71,208	$	7,580	$	281	$	81,787
Accumulated depreciation										
Balance at January 1, 2021	$	288	$	11,943	$	3,265	$	-	$	15,496
Depreciation		54		2,230		553		-		2,837
Disposals/retirements		-		(33)		(944)		-		(977)
Balance at December 31, 2021	$	342	$	14,140	$	2,874	$	-	$	17,356
Balance at January 1, 2020	$	237	$	9,883	$	2,589	$	-	$	12,709
Depreciation		51		2,094		681		-		2,826
Disposals/retirements		-		(34)		(5)		-		(39)
Balance at December 31, 2020	$	288	$	11,943	$	3,265	$	-	$	15,496
Carrying amounts										
At December 31, 2021	$	2,656	$	62,304	$	2,784	$	640	$	68,384
At December 31, 2020		2,430		59,265		4,315		281		66,291

At December 31, 2021 property plant and equipment with a carrying amount of $68,384 (2020 - $66,291) are subject to a general security agreement.

There were no borrowing costs capitalized as part of the cost of property, plant and equipment in 2020 and 2021.

(in thousands of dollars)

7. Intangible assets:

		Computer software		Land rights		Total
Cost						
Balance at January 1, 2021	$	1,408	$	238	$	1,646
Additions		249		-		249
Balance at December 31, 2021	$	1,657	$	238	$	1,895
Balance at January 1, 2020	$	1,116	$	237	$	1,353
Additions		292		1		293
Balance at December 31, 2020	$	1,408	$	238	$	1,646
Accumulated amortization						
Balance at January 1, 2021	$	680	$	31	$	711
Amortization		219		5		224
Balance at December 31, 2021	$	899	$	36	$	935
Balance at January 1, 2020	$	514	$	26	$	540
Amortization		166		5		171
Balance at December 31, 2020	$	680	$	31	$	711
Carrying amounts						
At December 31, 2021	$	758	$	202	$	960
At December 31, 2020		728		207		935

(in thousands of dollars)

8. Income tax expense:

Income tax expense is comprised of:

	2021	2020
Current tax expense	$ 460	$ 67
Deferred tax expense	171	51
	$ 631	$ 118

Reconciliation of effective tax rate:

	2021	2020
Income before taxes	$ 3,014	$ 677
Canada and Ontario statutory Income tax rates	26.5%	26.5%
Expected tax expense on income at statutory rates	799	$ 179
Increase in income taxes resulting from:		
Non-taxable amounts	86	31
Net movement in regulatory balances	(597)	(89)
Recapture of Capital Cost Allowance for tax purposes	411	-
Other items	(68)	(3)
Income tax expense	631	$ 118

Significant components of the Corporation's deferred tax balances:

	2021	2020
Deferred tax assets (liabilities) consist of the following:		
Property, plant, equipment (regulated)	$ (3,137)	$ (2,545)
Post-employment benefits	709	754
Deferred tax liabilities from regulated	(2,428)	(1,791)
Deferred tax liabilities from non-regulated solar assets	(22)	(447)
	$ (2,450)	$ (2,238)

9. Regulatory balances:

The Corporation has determined that certain debit and credit balances arising from rate-regulated activities qualify for regulatory accounting treatment in accordance with IFRS 14 and the OEB's prescribed accounting procedures for electricity distributors. The regulatory balances are comprised of regulatory debit balances of $14,119 (2020 - $15,181) and regulatory credit balances for $3,168 (2020 - $4,367) for a net regulatory asset of $10,951 (2020 - $10,814).

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points, with the exception of the tax balances. In 2021, the rate was 0.57% for the period January to December.

The regulatory balances for the Corporation consist of the following:

(a) Settlement Variance:

This account includes the variances between amounts charged by the Corporation, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by the Corporation such as commodity charges, retail transmission rates and wholesale market services charges. The Corporation has deferred the variances and related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. This account also includes variances between the amounts approved for disposition by the OEB and the amounts collected or paid through OEB approved rate riders.

Settlement variances are reviewed annually as part of a COS or IRM application submitted to the OEB and a request for disposition is made if the aggregate of the settlement accounts exceeds the OEB's prescribed materiality level.

(b) Regulatory settlement accounts:

Regulatory settlement accounts include those settlement variances for which the OEB has approved for disposition. On March 25, 2021, the OEB issued a final rate order approving 2021 rates effective May 1, 2021.

(c) Customer Liability for Deferred Taxes:

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from or paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

(in thousands of dollars)

9. Regulatory balances (continued):

(d) Other:

This deferral account includes the allowable costs associated with the transition to IFRS and other miscellaneous regulatory accounts.

Reconciliation of the carrying amount for each class of regulatory balances

Regulatory deferral account debit balances	January 1, 2021	Additions/ transfers	Recovery/ reversal	December 31, 2021	Remaining years
Group 1 deferred accounts	$ 6,401	$ 500	$ (681)	$ 6.220	1-2
Regulatory transition to IFRS	148	-	-	148	3
Regulatory settlement account	7,108	116	(1,486)	5,738	1-2
Other regulatory accounts	237	1	(109)	129	3
Income tax	1,287	597	-	1,884	3
	$ 15,181	$ 1,214	$ (2,276)	$ 14,119	

Regulatory deferral account debit balances	January 1, 2020	Additions/ transfers	Recovery/ reversal	December 31, 2020	Remaining years
Group 1 deferred accounts	$ 7,418	$ 2,059	$ (3,076)	$ 6,401	1-2
Regulatory transition to IFRS	-	148	-	148	3
Regulatory settlement account	4,572	3,295	(759)	7,108	1-2
Other regulatory accounts	233	232	(228)	237	3
Income tax	1,198	89	-	1,287	3
	$ 13,421	$ 5,823	$ (4,063)	$ 15,181	

Regulatory deferral account credit balances	January 1, 2021	Additions/ transfers	Recovery/ reversal	December 31, 2021	Remaining years
Group 1 deferred accounts	$ (2,229)	$ 856	$ 1,138	$ (235)	1-2
Regulatory transition to IFRS	-	-	-	-	3
Regulatory settlement account	(1,863)	(291)	(351)	(2,505)	1-2
Other regulatory accounts	(275)	(153)	-	(428)	3
Income tax	-	-	-	-	3
	$ (4,367)	$ 412	$ 787	$ (3,168)	

Regulatory deferral account credit balances	January 1, 2020	Additions/ transfers	Recovery/ reversal	December 31, 2020	Remaining years
Group 1 deferred accounts	$ (1,602)	$ (627)	$ -	$ (2,229)	1-2
Regulatory transition to IFRS	(607)	-	607	-	3
Regulatory settlement account	(1,584)	(3,499)	3,220	(1,863)	1-2
Other regulatory accounts	(238)	(149)	112	(275)	3
Income tax	-	-	-	-	3
	$ (4,031)	$ (4,275)	$ 3,939	$ (4,367)	

1. These balances will be recovered over the life of the related capital assets.

The “Additions/Transfers” column consists of new additions to regulatory balances (for both debits and credits). The “Recovery/Reversal” column consists of amounts collected or paid through rate riders or transactions reversing an existing regulatory balance to recover. Recoveries and reversals occur as a result of the approval of an application. There were no reversals of regulatory balances for the year ended December 31, 2021.

(in thousands of dollars)

10. Accounts payable and accrued liabilities:

		2021		2020
Accounts payable – energy purchases	$	5,357	$	5,800
Due to related parties		115		6
Payroll payable		283		304
Water and waste water billings due to Ultimate Shareholders		2,514		4,033
Other accounts payable and accrued liabilities		1,908		1,956
	$	10,177	$	12,099

11. Long-term debt:

		2021		2020
Related party long-term loan payable is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each March. Interest is payable at a stated interest rate of 3.8%. The agreement expires December 31, 2022. The debt is owing to two of the four shareholders of the parent company as follows:				
Municipality of Leamington	$	2,150	$	2,150
Town of Tecumseh		1,545		1,545
		3,695		3,695
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $36, bearing an interest rate of 3.25% due November, 2029		3,053		3,386
Fixed rate loan – TD Canada Trust is a 5 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $5, bearing an interest rate of 2.19% repaid during the year		-		833
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $17, bearing an interest rate of 3.18% due August, 2027		2,502		2,623
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.73% due July, 2028		2,631		2,744

(in thousands of dollars)

11. Long-term debt (continued):

		2021		2020
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.73% due July, 2028		2,631		2,744
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.90% due November, 2028		2,676		2,785
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $39, bearing an interest rate of 2.95% due June, 2029		6,403		6,672
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $26, bearing an interest rate of 2.00% due November, 2030		4,927		5,157
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $31, bearing an interest rate of 2.079% due December, 2030.		5,755		6,000
Fixed rate loan – TD Canada Trust is a 5 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $21, bearing an interest rate of 2.19% due October, 2026.		3,973		-
		38,246		36,639
Less: Current portion of long-term debt		5,418		5,323
	$	32,828	$	31,316

Approximate long-term principal repayments over the next five years and thereafter are as follows:

2022	$	5,418
2023		1,773
2024		1,823
2025		1,879
2026		5,062
Thereafter		22,291
	$	38,246

The loans are secured by a General Security Agreement over the assets of the Corporation.

(in thousands of dollars)

12. Post-employment benefits:

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2021, the Corporation made employer contributions of $405 to OMERS (2020 - $402) of which $121 (2020 - $121) has been capitalized as part of property, plant and equipment. The Corporation estimates that a contribution of $400 to OMERS will be made during the next fiscal year.

(b) Post-employment benefits other than pension:

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans. The most recent valuation was completed December 31, 2020.

As a strategy to reduce sick time costs and promote employee retention, the company granted additional retirement benefits to employees in 2020.

As a result of the strategy adopted by the Corporation, plan amendments were recognized immediately in profit or loss in the amount of $nil (2020 - $368).

Reconciliation of the obligation	2021	2020
Defined benefit obligation, beginning of year	$ 2,844	$ 2,732
Included in profit or loss		
Current service cost	70	60
Interest cost	64	93
Plan amendments	-	368
	2,978	3,253
Benefits paid	(152)	(135)
	2,826	3,118
Actuarial (gains)/losses included in OCI:		
Changes in discount rate	(129)	194
Changes in demographic assumptions	(23)	(220)
Changes in trend rate assumptions	-	36
Effect of premium experience	-	(284)
	(152)	(274)
Defined benefit obligation, end of year	$ 2,674	$ 2,844

(in thousands of dollars)

12. Post-employment benefits (continued):

(b) Post-employment benefits other than pension (continued):

Actuarial assumptions	2021	2020
Discount (interest) rate	2.75%	2.25%
General inflation	2.00%	2.00%
Medical Costs	6.25%	6.25%
Dental Costs	4.50%	4.50%

Medical costs are estimated to increase at a rate which declines over time from 6.25% per annum in 2021 to 4.5% by 2027.

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $243. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $283.

A 1% increase in the assumed trend rate would result in the defined benefit obligation increasing by $243. A 1% decrease in the assumed trend rate would result in the defined benefit obligation decreasing by $213.

13. Share capital:

	2021	2020
Authorized:		
Unlimited number of common shares, Class A, voting		
Unlimited number of common shares, Class B, non-voting		
Issued:		
50 common shares, Class A voting, and		
15,772,796 common shares, Class B non-voting	$ 15,773	$ 15,773

Dividends

The holders of the common shares are entitled to receive dividends from time to time.

The Corporation paid aggregate dividends in the year on common shares of $0.06771 (2020 - $0.07888) per share which amount to total dividends declared in the year of $1,068 (2020 - $1,244).

(in thousands of dollars)

14. Revenue:

Revenue consists of the following:

		2021		2020
Revenue from contracts with customers				
Sale of energy	$	69,438	$	77,342
Distribution revenue		14,864		13,161
Solar Generation		26		383
Ancillary services revenue		(7)		(8)
Billing services to Municipal shareholders		403		570
Joint use pole rentals		308		293
Other regulatory service charges		368		223
Miscellaneous		228		8
Revenue from other sources				
Deferred revenue recognized from capital contributions		185		162
	$	85,813	$	92,134

Sale of energy and distribution revenue consist of the following:

		2021		2020
Residential service	$	54,634	$	58,566
General service less than 50KW		7,922		8,550
General service 50 to 4,999KW		21,238		22,590
Intermediate and Embedded distributor		367		355
Unmetered and other		141		442
	$	84,302	$	90,503

15. Operating expenses:

		2021		2020
Contract/consulting	$	1,057	$	1,207
Materials and supplies		1,375		1,350
Salaries, wages and benefits		3,042		2,905
Cost of billing services for ultimate shareholders		367		519
Post-employment benefit plans		139		121
Vehicles		45		146
Management charges from Parent		967		965
Bad debts (recovery)		(2)		143
Amortization of deferred charges		-		71
Other		869		761
	$	7,859	$	8,188

(in thousands of dollars)

16. Net finance costs:

		2021		2020
Finance income				
Interest income on bank deposits	$	10	$	21
Finance costs				
Interest expense on long-term debt		1,092		1,002
Interest expense on customer deposits		3		10
Other		38		126
		1,133		1,138
Net finance costs recognized in profit or loss	$	(1,123)	$	(1,117)

17. Commitments and contingencies:

Contractual Obligations:

General:

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation 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 Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance:

The Corporation 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.

Letter of Credit:

A letter of credit in the amount of $2,900 has been issued by TD Canada Trust to the credit of the Independent Electricity System Operator for the commodity purchases and market services provided. This letter of credit has no term of expiry and is normally renewed annually.

(in thousands of dollars)

18. Related party transactions:

(a) Parent and ultimate controlling party:

The sole shareholder of the Corporation is Essex Power Corporation (“EPC”) which is wholly owned by Towns of Amherstburg, LaSalle and Tecumseh, and the Municipality of Leamington (“ultimate parents”). The ultimate parents produce financial statements that are available for public use.

(b) Outstanding balances with related parties:

		2021		2020
Balances due to:				
Essex Power Corporation	$	99	$	-
Essex Energy Corporation		225		324
Essex Power Services Corporation		-		2
Utilismart Corporation		31		32
Wattsworth Analysis Inc.		3		3
Municipality of Leamington		82		1,670
Town of Tecumseh		1,011		1,072
Town of Amherstburg		1,503		1,432
	$	2,954	$	4,535

		2021		2020
Balances due from:				
Essex Power Corporation	$	-	$	1
Essex Power Services Corporation		-		8
Essex Energy Corporation		16		22
Town of LaSalle		1		1
Town of Tecumseh		33		15
Town of Amherstburg		29		15
Municipality of Leamington		20		24
	$	99	$	86

All balances due from and due to related parties listed above are included within accounts receivable and accounts payable respectively. Amounts are non-interest bearing with repayment terms similar to other trade accounts receivable and accounts payable. The amounts disclosed separately as due from related parties or due to related parties, as well as the sub debt payable – shareholder which is non-interest bearing and due within 2021.

(c) Transactions with parent:

During the year, the corporation paid management fees of $967 (2020- $965) to its parent.

(in thousands of dollars)

18. Related party transactions (continued):

(d) Transaction with companies under common control:

In the ordinary course of business, the corporation incurred the following transactions with other related parties under common control:

		2021		2020
Sold operating expense services to:				
Essex Power Services Corporation	$	47	$	89
Essex Energy Corporation		66		22
Purchased operating expense and solar services from:				
Essex Energy Corporation		858		1,130
Essex Power Services Corporation		15		47
Utilismart Corporation		372		370
Wattsworth Analysis Inc.		36		36

(e) Transactions with ultimate parent:

The Corporation delivers electricity to these entities throughout the year for the electricity needs of the Towns and Municipality. Electricity delivery charges are at prices and under terms approved by the OEB. The Corporation also provides additional services to the Towns and Municipality, including billing and customer care services. The total revenues related to these services for 2021 were $403 (2020 - $570).

(f) Key management personnel:

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members. The compensation paid or payable is as follows:

		2021		2020
Directors' fees	$	21	$	6
Salaries, bonuses and other short-term benefits		480		410
	$	501	$	416

19. Financial instruments and risk management:

Fair value disclosure:

The carrying values of accounts receivable, unbilled revenue, accounts payable and accrued liabilities and bank indebtedness 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.

The fair value of the long-term debt at December 31, 2021 is $36,794 (2020 - $33,801). The fair value is calculated based on the present value of the future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rate used to calculate fair value at December 31, 2021 was 3.0% (2020 – 3.0%). All financial instruments are considered level 1 on the fair value hierarchy.

Financial risks:

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation'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.

(a) 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 Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Towns of Amherstburg, LaSalle, Tecumseh and the Municipality of Leamington. No single customer accounts for a balance in excess of 7% of total electricity 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 profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the loss allowance at December 31, 2021 is $126 (2020 - $211). An impairment recovery of $2 (2020 - $143 impairment loss) was recognized during the year.

19. Financial instruments and risk management (continued):

Financial risks (continued):

(a) Credit risk (continued):

The Corporation's credit risk associated with accounts receivable is primarily related to payments from its electricity distribution customers. At December 31, 2021, approximately $251 (2020 - $290) is considered 60 or more days past due. The Corporation has over 33,000 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 Corporation holds security deposits in the amount of $717 (2020 - $845).

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation'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.

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $9,000 credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2021, $nil had been drawn under the Corporation's credit facility and is presented in bank indebtedness on the statement of financial position.

The Corporation also has a bilateral facility for $2,900 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which none has been drawn and posted with the IESO during 2021 or 2020.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days. Customer deposits are due on demand. The scheduled repayments associated with long-term debt are described within note 11.

19. Financial instruments and risk management (continued):

(d) Capital disclosures:

The main objectives of the Corporation, 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 Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2021, shareholder's equity amounts to $30,509 (2020 - $28,945) and long-term debt amounts to $38,246 (2020 - $36,639).

Attachment 1-F

2023 Audited Financial Statements

Financial Statements of

ESSEX POWERLINES CORPORATION

And Independent Auditor's Report thereon

Year ended December 31, 2023
(Expressed in thousands of dollars)

KPMG LLP
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3200 Deziel Drive
Windsor, ON N8W 5K8
Canada
Telephone 519 251 3500
Fax 519 251 3530

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Essex Powerlines Corporation

Opinion

We have audited the financial statements of Essex Powerlines Corporation (the "Entity"), which comprise:

- the statement of financial position as at December 31, 2023
- the statement of comprehensive income for the year then ended
- the statement of changes in 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 Entity as at December 31, 2023, and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting 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 Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled are other ethical 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 Accounting Standards, 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 Entity'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 Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity'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 Entity'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 Entity'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 Entity 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 represent 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

Windsor, Canada
April 18, 2024

ESSEX POWERLINES CORPORATION

Statement of Financial Position
As at December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Note	2023	2022
Assets			
Current assets			
Cash and cash equivalents		$ 839	$ 1
Accounts receivable	4	6,795	6,207
Unbilled revenue		6,627	6,657
Income taxes receivable	8	384	644
Materials and supplies	5	1,691	1,197
Prepaid expenses		329	301
Total current assets		16,665	15,007
Non-current assets			
Property, plant and equipment	6	78,808	72,417
Intangible assets	7	1,922	1,111
Total non-current assets		80,730	73,528
Total assets		97,395	88,535
Regulatory balances	9	8,814	11,605
Total assets and regulatory balances		$ 106,209	$ 100,140

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Financial Position
As at December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Note	2023	2022
Liabilities			
Current liabilities			
Bank indebtedness		$ –	$ 3,221
Accounts payable and accrued liabilities	10	11,601	10,132
Long-term debt due within one year	11	3,420	2,512
Customer deposits		1,903	1,436
Dividend payable		1,100	1,084
Total current liabilities		18,024	18,385
Non-current liabilities			
Long-term debt	11	35,329	34,010
Post-employment benefits	12	2,115	2,185
Deferred revenue		11,634	8,595
Deferred tax liabilities	8	3,681	3,156
Total non-current liabilities		52,759	47,946
Total liabilities		70,783	66,331
Equity			
Share capital	13	15,773	15,773
Retained earnings		14,291	13,793
Accumulated other comprehensive income		1,840	1,804
Total equity		31,904	31,370
Total liabilities and equity		102,687	97,701
Regulatory balances	9	3,522	2,439
Total liabilities, equity and regulatory balances		$ 106,209	$ 100,140

See accompanying notes to the financial statements.

On behalf of the Board:

Michael D Prue Director

Director

ESSEX POWERLINES CORPORATION

Statement of Comprehensive Income
Year ended December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Note	2023	2022
Revenue			
Sale of energy		$ 67,435	$ 69,709
Distribution revenue		17,589	17,616
Solar generation		24	25
Other		1,260	1,193
	14	86,308	88,543
Operating expenses			
Cost of power purchased		66,326	71,029
Operating expenses	15	9,172	8,697
Solar expenses		6	7
Depreciation and amortization		3,615	3,285
Research and development SR&ED ITC reversed		–	19
		79,119	83,037
Income from operating activities		7,189	5,506
Net finance costs	16	(1,228)	(1,168)
Income before income taxes		5,961	4,338
Current tax expense	8	(23)	3
Deferred tax expense	8	512	591
Net income for the year		5,472	3,744
Net movement in regulatory balances, net of tax	9	(3,874)	(1,785)
Net income for the year and net movement in regulatory balances		1,598	1,959
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Re-measurements of post-employment benefits	12	49	434
Tax on re-measurements		(13)	(115)
Other comprehensive income for the year		36	319
Total comprehensive income for the year		$ 1,634	$ 2,278

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Changes in Equity
Year ended December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Share capital	Solar Equity	Retained earnings	Accumulated other comprehensive income (Loss)	Total
Balance at January 1, 2022	$ 15,773	$ –	$ 13,251	$ 1,485	$ 30,509
Net income and net movement in regulatory balances	–	–	1,959	–	1,959
Other comprehensive income	–	–	–	319	319
Prior period adjustment	–	–	(333)	–	(333)
Dividends	–	–	(1,084)	–	(1,084)
Balance at December 31, 2022	$ 15,773	$ –	$ 13,793	$ 1,804	$ 31,370
Balance at January 1, 2023	$ 15,773	$ –	$ 13,793	$ 1,804	$ 31,370
Net income and net movement in regulatory balances	–	–	1,598	–	1,598
Other comprehensive income	–	–	–	36	36
Dividends	–	–	(1,100)	–	(1,100)
Balance at December 31, 2023	$ 15,773	$ –	$ 14,291	$ 1,840	$ 31,904

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Cash Flows
Year ended December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	2023	2022
Operating activities		
Net Income and net movement in regulatory balances	$ 1,598	$ 1,959
Adjustments for:		
Depreciation and amortization	3,615	3,285
Amortization of deferred revenue	(273)	(221)
Post-employment benefits	(21)	(55)
Net finance costs	1,228	1,168
Income tax expense	489	594
	6,636	6,730
Change in non-cash operating working capital:		
Accounts receivable	(588)	(756)
Unbilled revenue	30	(946)
Materials and supplies	(494)	(243)
Customer deposits	467	178
Prepaid expenses	(28)	(169)
Accounts payable and accrued liabilities	1,469	(45)
	856	(1,981)
Net movement in regulatory balances	3,874	1,785
Income tax received (paid)	283	(879)
Interest paid	(1,259)	(1,185)
Interest received	31	17
Net cash from operating activities	10,421	4,487
Investing activities		
Purchase of property, plant and equipment	(9,673)	(7,123)
Purchase of intangible assets	(1,196)	(415)
Proceeds on disposal of property, plant and equipment	52	69
Contributions received from customers	3,312	1,634
Net cash used by investing activities	(7,505)	(5,835)
Financing activities		
Dividends paid	(1,084)	(1,068)
Proceeds from long-term debt	4,000	–
Repayment of long-term debt	(1,773)	(1,724)
Net cash from (used by) financing activities	1,143	(2,792)
Change in cash, cash equivalents and bank indebtedness	4,059	(4,140)
Cash and cash equivalents and bank indebtedness, beginning of year	(3,220)	920
Cash, cash equivalents and bank indebtedness, end of year	$ 839	$ (3,220)

See accompanying notes to the financial statements.

1. Reporting entity:

Essex Powerlines Corporation (the "Corporation") is a rate regulated, municipally owned local distribution company ("LDC") which is wholly owned by Essex Power Corporation, which in turn, is wholly owned by the shareholders of Essex Power Corporation including the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The Corporation was incorporated on April 18, 2000 under the *Business Corporations Act* (Ontario), in accordance with the *Electricity Act*. The Corporation is located in Oldcastle, Ontario. The address of the Corporation's registered office is 2730 Highway 3, Oldcastle, ON N0R 1L0.

The Corporation delivers electricity and related energy services to residential and commercial customers in Amherstburg, LaSalle, Leamington and Tecumseh, under a license issued by the Ontario Energy Board ("OEB"). The Corporation is regulated by the OEB and adjustments to the Corporation's distribution and power rates require OEB approval.

The financial statements are for the Corporation as at and for the year ended December 31, 2023.

2. Basis of presentation:

(a) Statement of compliance:

The Corporation's financial statements have been prepared in accordance with IFRS Accounting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 18, 2024.

(b) Basis of measurement:

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

(d) Use of estimates and judgments:

(i) Assumptions and estimation uncertainty:

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 years affected.

2. Basis of presentation (continued):

(d) Use of estimates and judgments (continued):

(i) Assumptions and estimation uncertainty (continued):

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

a) Notes 3 (d), (e), (f), 6, 7 – estimation of useful lives of its property, plant and equipment and intangible assets and related impairment tests on long-lived assets

b) Notes 3 (h), 9 – recognition and measurement of regulatory balances

c) Notes 3 (i), 12 – measurement of defined benefit obligations: key actuarial assumptions

d) Note 17 – recognition and measurement of provisions and contingencies

(ii) Judgments:

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following note:

a) Note 3 (j) – leases: whether an arrangement contains a lease

b) Note 3 (b) – determination of the performance obligation for contributions from customers and the related amortization period

c) Notes 3(h), 9 – recognition of regulatory balances

(e) Rate regulation:

The Corporation 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, such as the Corporation, 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 LDC's 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.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

Rate setting

(i) Distribution Rates:

The Corporation files a "Cost of Service" ("COS") rate application every five years, unless approved for a deferral, under which the OEB establishes the revenues required to recover the forecasted operating costs, including amortization and income taxes, of providing the regulated electricity distribution service and providing a fair return on the Corporation's rate base. The Corporation 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 any registered interveners. Rates are approved based upon the review of evidence and information, including any revisions resulting from that review.

In the intervening years, an Incentive Regulation 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 set by the OEB and a "stretch factor" determined by the relative efficiency of an electricity distributor.

On August 28, 2017, the Corporation submitted a COS rate application to the OEB to change distribution rates effective May 1, 2018. The application was approved by the OEB on October 10, 2018.

On November 1, 2022, the Corporation submitted an IRM Application to the OEB requesting approval to change distribution rates effective May 1, 2023. The IRM Application, which provided a mechanistic and formulaic adjustment to distribution rates and charges, was approved by the OEB on March 23, 2023. The GDP IPI-FDD for 2024 is 3.70%, the Corporation's stretch factor is 0.15% and the productivity factor determined by the OEB is 0%, resulting in a net adjustment of 3.55% to the previous year's rates.

(ii) Electricity Rates:

The OEB sets Ontario electricity prices for low-volume consumers annually each year in 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*.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

(ii) Electricity Rates (continued):

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.

(iii) Retail Transmission Rates:

These are the costs of delivering electricity from generating stations across the Province to local distribution networks. These charges include the costs to build and maintain the transmission lines, towers and poles and operate provincial transmission systems. Retail transmission rates are passed through to the operators of transmission networks and facilities.

(iv) Wholesale Market Service Rates:

These are the costs of administering the wholesale electricity system and maintaining the reliability of the provincial grid and include the costs associated with funding Ministry of Energy conservation and renewable energy programs. The Corporation is billed for the cost of the wholesale electricity system by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

3. Material accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

In addition, the Corporation adopted Disclosure of *Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2)* from January 1, 2023. The amendments require the disclosure of “material”, rather than “significant”, accounting policies. Although the amendment did not result in a change to the accounting policies themselves, they impacted the accounting policy information disclosed in Note 3 in certain instances.

(a) Financial instruments:

All financial assets and all financial liabilities 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(f).

The Corporation does not enter into derivative instruments. Hedge accounting has not been used in the preparation of these financial statements.

Cash equivalents may include short-term investments with maturities of three months or less when purchased.

(b) Revenue recognition:

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. 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 Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

3. Material accounting policies (continued):

(b) Revenue recognition (continued):

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, received from developers are 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 Corporation'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 useful life of the related asset.

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.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants and the related performance incentive payments under Conservation and Demand Management (“CDM”) programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies:

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on a weighted average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

3. Material accounting policies (continued):

(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 date of transition to IFRS, 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 contracted services, materials and transportation costs, direct labour, borrowing costs 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 Corporation's borrowings. Qualifying assets are considered to be those that take in excess of nine months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included 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 Corporation 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.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

	Years
Buildings	50
Distribution equipment	15 – 50
Computer hardware and equipment	5 – 10
Office equipment	10
Utility equipment and trucks	7 – 10
Solar generation	20

3. Material accounting policies (continued):

(e) Intangible assets:

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the date of transition to IFRS, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

	Years
Computer software	5
Land rights	50

(f) Impairment:

(i) Financial assets measured at amortized cost:

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

(ii) Non-financial assets:

The carrying amounts of the Corporation's non-financial assets, other than 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.

3. Material accounting policies (continued):

(f) Impairment (continued):

(ii) Non-financial assets (continued) :

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" or “CGU”). The recoverable amount of an asset or CGU 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.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorated basis, if applicable.

An impairment loss in respect of goodwill is not reversed. For other assets, 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 or amortization, if no impairment loss had been recognized.

For the regulated business, the carrying costs of most of the Corporation's non-financial assets are included in rate base (the aggregate of approved investment in PP&E and intangible assets, excluding construction in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital) where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

(g) Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills and deposits. Interest is paid on customer deposits. Deposits are also received for planned chargeable work. No interest is paid on these deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

3. Material accounting policies (continued):

(h) Regulatory balances:

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of recognizing regulatory balances in accordance with its previous Generally Accepted Accounting Principles ("GAAP") when it adopts IFRS. An entity is permitted to apply the requirements of this standard in its first IFRS financial statements if it conducts rate-regulated activities and recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP. IFRS 14 is effective for periods beginning on or after January 1, 2016, however, early application was permitted. The Corporation elected to apply this Standard in its first IFRS financial statements as at December 31, 2015.

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or other comprehensive income ("OCI"). When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the amounts are returned to the customer at rates approved by the OEB the amounts are recognized as a reduction of revenue.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

3. **Material accounting policies (continued):**

(i) Post-employment benefits:

(i) Pension plan:

The Corporation provides a pension plan for some of its full-time employees through Ontario Municipal Employees Retirement System ("OMERS"). OMERS is a multi-employer pension plan that provides pensions for employees of Ontario municipalities, local boards and public utilities. OMERS is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by investment earnings. To the extent that the plan finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension:

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

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.

(j) Leased assets:

At inception of a contract, the Corporation assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

3. Material accounting policies (continued):

(j) Leased assets (continued):

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Corporation's incremental borrowing rate.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The Corporation has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Corporation 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):

(k) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is 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 Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Payments in lieu of taxes and payments under the Tax Acts are collectively referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss 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 tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

3. Significant accounting policies (continued):

(l) Accounting standards issued but not yet effective:

The following standards which are not yet effective for the year ended December 31, 2023, have not been applied in preparing these financial statements.

(i) Classification of Liabilities as Current or Non-Current (Amendments to IAS 1)

On January 23, 2020, the IASB issued amendments to IAS 1 *Presentation of Financial Statements*, to clarify the classification of liabilities as current or non-current.

On October 31, 2022, the IASB issued *Non-current Liabilities with Covenants (Amendments to IAS 1)* (the 2022 amendments), to improve the information a company provides about long-term debt with covenants.

The 2020 amendments and the 2022 amendments (collectively "the Amendments") are effective for annual periods beginning on or after January 1, 2024.

(ii) Lease Liability in a Sale and Leaseback (Amendments to IFRS 16 Leases)

On September 22, 2022, the IASB issued *Lease Liability in a Sale and Leaseback (Amendments to IFRS 16).*

The amendments are effective for annual periods beginning on or after January 1, 2024.

(iii) Supplier Finance Arrangements (Amendments to IAS 7 and IFRS 7)

On May 25, 2023, the IASB issued amendments to IAS 7 *Statement of Cash Flows* and IFRS 7 *Financial Instruments: Disclosures.*

The amendments are effective for annual periods beginning on or after January 1, 2024.

(iv) Lack of exchangeability (Amendments to IAS 21)

On August 15, 2023, the IASB issued amendments to IAS 21 *The Effects of Changes in Foreign Exchange Rates* to clarify when a currency is exchangeable into another currency and how a company estimates a spot rate when a currency lacks exchangeability.

The amendments apply for annual reporting periods beginning on or after January 1, 2025, with earlier application permitted.

The Corporation has assessed the potential impacts on its financial statements, and determined that the future pronouncements will not have a material impact on the Corporation.

(in thousands of dollars)

4. Accounts receivable:

	2023	2022
Trade receivables	$ 6,222	$ 5,650
Due from related parties	115	81
Other receivables	624	552
Billable work	65	49
Less:		
Loss allowance	(231)	(125)
	$ 6,795	$ 6,207

5. Materials and supplies:

Amount written down due to obsolescence in 2023 was $nil (2022 - $nil).

6. Property, plant and equipment:

	Land and buildings	Distribution equipment	Other fixed assets	Construction in-Progress	Total
Cost					
Balance at January 1, 2023	$ 3,223	$ 82,342	$ 6,380	$ 626	$ 92,571
Additions	730	7,976	1,091	–	9,797
Disposals/retirements	(20)	(70)	(77)	–	(167)
Balance at December 31, 2023	$ 3,933	$ 90,248	$ 7,394	$ 626	$ 102,201
Balance at January 1, 2022	$ 2,998	$ 76,444	$ 5,658	$ 640	$ 85,740
Additions	225	5,989	799	110	7,123
Disposals/retirements	–	(91)	(77)	–	(168)
Balance at December 31, 2022	$ 3,223	$ 82,342	$ 6,380	$ 750	$ 92,695
Accumulated depreciation					
Balance at January 1, 2023	$ 401	$ 16,482	$ 3,395	$ –	$ 20,278
Depreciation	68	2,538	624	–	3,230
Disposals/retirements	(1)	(37)	(77)	–	(115)
Balance at December 31, 2023	$ 468	$ 18,983	$ 3,942	$ –	$ 23,393
Balance at January 1, 2022	$ 342	$ 14,140	$ 2,874	$ –	$ 17,356
Depreciation	59	2,376	586	–	3,021
Disposals/retirements	–	(34)	(65)	–	(99)
Balance at December 31, 2022	$ 401	$ 16,482	$ 3,395	$ –	$ 20,278
Carrying amounts					
At December 31, 2023	$ 3,465	$ 71,265	$ 3,452	$ 626	$ 78,808
At December 31, 2022	$ 2,822	$ 65,860	$ 2,985	$ 750	$ 72,417

At December 31, 2023 property plant and equipment with a carrying amount of $78,808 (2022 - $72,417) are subject to a general security agreement.

There were no borrowing costs capitalized as part of the cost of property, plant and equipment in 2023 or 2022.

(in thousands of dollars)

7. Intangible assets:

	Computer software	Land rights	Total
Cost			
Balance at January 1, 2023	$ 2,072	$ 238	$ 2,310
Additions	1,196	–	1,196
Balance at December 31, 2023	$ 3,268	$ 238	$ 3,506
Balance at January 1, 2022	$ 1,657	$ 238	$ 1,895
Additions	415	–	415
Balance at December 31, 2022	$ 2,072	$ 238	$ 2,310
Accumulated amortization			
Balance at January 1, 2023	$ 1,158	$ 41	$ 1,199
Amortization	380	5	385
Balance at December 31, 2023	$ 1,538	$ 46	$ 1,584
Balance at January 1, 2022	$ 899	$ 36	$ 935
Amortization	259	5	264
Balance at December 31, 2022	$ 1,158	$ 41	$ 1,199
Carrying amounts			
At December 31, 2023	$ 1,730	$ 192	$ 1,922
At December 31, 2022	$ 914	$ 197	$ 1,111

(in thousands of dollars)

8. Income tax expense:

Income tax expense is comprised of:

	2023	2022
Current tax expense	$ (23)	$ 3
Deferred tax expense	512	591
	$ 489	$ 594

Reconciliation of effective tax rate:

	2023	2022
Income before taxes	$ 5,961	$ 4,338
Canada and Ontario statutory Income tax rates	26.5%	26.5%
Expected tax expense on income at statutory rates	1,579	1,149
Increase in income taxes resulting from:		
Non-taxable amounts	92	103
Net movement in regulatory balances	(514)	(656)
Other items	(668)	(2)
Income tax expense	$ 489	$ 594
Effective income tax rate	8.2%	13.7%

Significant components of the Corporation's deferred tax balances:

	2023	2022
Deferred tax assets (liabilities) consist of the following:		
Property, plant, equipment (regulated)	$ (4,704)	$ (3,812)
Post-employment benefits	560	579
Total deferred tax liabilities to be realized by customers	(4,144)	(3,233)
Deferred tax liabilities from non-regulated solar assets	(18)	(20)
Other deferred tax assets	481	97
	$ (3,681)	$ (3,156)

9. Regulatory balances:

The Corporation has determined that certain debit and credit balances arising from rate-regulated activities qualify for regulatory accounting treatment in accordance with IFRS 14 and the OEB's prescribed accounting procedures for electricity distributors. The regulatory balances are comprised of regulatory debit balances of $8,814 (2022 - $11,605) and regulatory credit balances of $3,522 (2022 - $2,439) for a net regulatory asset of $5,292 (2022 - $9,166).

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points, with the exception of the tax balances. In 2023, the rate was 4.73% for the period January to March, 4.98% for the period April to September and 5.49% for the period for the period October to December.

The regulatory balances for the Corporation consist of the following:

(a) Settlement Variance:

This account includes the variances between amounts charged by the Corporation, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by the Corporation such as commodity charges, retail transmission rates and wholesale market services charges. The Corporation has deferred the variances and related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. This account also includes variances between the amounts approved for disposition by the OEB and the amounts collected or paid through OEB approved rate riders.

Settlement variances are reviewed annually as part of a COS or IRM application submitted to the OEB and a request for disposition is made if the aggregate of the settlement accounts exceeds the OEB's prescribed materiality level.

(b) Regulatory settlement accounts:

Regulatory settlement accounts include those settlement variances for which the OEB has approved for disposition. On March 23, 2023, the OEB issued a final rate order approving 2023 rates effective May 1, 2023.

(c) Customer Liability for Deferred Taxes:

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from or paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

(in thousands of dollars)

9. Regulatory balances (continued):

(d) Other:

This deferral account includes the allowable costs associated with the transition to IFRS and other miscellaneous regulatory accounts.

Reconciliation of the carrying amount for each class of regulatory balances:

Regulatory deferral account debit balances	January 1, 2023	Additions/ transfers	Recovery/ reversal	December 31, 2023	Remaining years
Group 1 deferred accounts	$ 5,875	$ (1,944)	$ (257)	$ 3,674	1
Regulatory transition to IFRS	148	–	–	148	1-2
Regulatory settlement account	2,879	25	(1,423)	1,481	1
Other regulatory accounts	163	294	–	457	1-2
Income tax	2,540	514	–	3,054	1-2
	$ 11,605	$ (1,111)	$ (1,680)	$ 8,814	

Regulatory deferral account debit balances	January 1, 2022	Additions/ transfers	Recovery/ reversal	December 31, 2022	Remaining years
Group 1 deferred accounts	$ 6,220	$ 1,524	$ (1,869)	$ 5,875	1-2
Regulatory transition to IFRS	148	–	–	148	3
Regulatory settlement account	5,738	34	(2,893)	2,879	1-2
Other regulatory accounts	129	34	–	163	3
Income tax	1,884	656	–	2,540	3
	$ 14,119	$ 2,248	$ (4,762)	$ 11,605	

Regulatory deferral account credit balances	January 1, 2023	Additions/ transfers	Recovery/ reversal	December 31, 2023	Remaining years
Group 1 deferred accounts	$ (244)	$ 797	$ (808)	$ (255)	1
Regulatory settlement account	(1,670)	1,736	(2,681)	(2,615)	1
Other regulatory accounts	(525)	(127)	–	(652)	1-2
	$ (2,439)	$ 2,406	$ (3,489)	$ (3,522)	

Regulatory deferral account credit balances	January 1, 2022	Additions/ transfers	Recovery/ reversal	December 31, 2022	Remaining years
Group 1 deferred accounts	$ (234)	$ (104)	$ 94	$ (244)	1-2
Regulatory settlement account	(2,506)	(273)	1,109	(1,670)	1-2
Other regulatory accounts	(428)	(97)	–	(525)	3
	$ (3,168)	$ (474)	$ 1,203	$ (2,439)	

The “Additions/Transfers” column consists of new additions to regulatory balances (for both debits and credits). The “Recovery/Reversal” column consists of amounts collected or paid through rate riders or transactions reversing an existing regulatory balance to recover. Recoveries and reversals occur as a result of the approval of an application. There were no reversals of regulatory balances for the year ended December 31, 2023.

(in thousands of dollars)

10. Accounts payable and accrued liabilities:

		2023		2022
Accounts payable – energy purchases	$	6,048	$	5,488
Payroll payable		258		301
Due to related parties		868		453
Water and waste water billings due to Ultimate Shareholders		2,730		2,774
Other accounts payable and accrued liabilities		1,697		1,116
	$	11,601	$	10,132

11. Long-term debt:

		2023		2022
Related party long-term loan payable is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each March. Interest is payable at a stated interest rate of 4.0% (2022 - 3.8%). The agreement expires December 31, 2027. The debt is owing to two of the four shareholders of the parent company as follows:				
Municipality of Leamington	$	2,150	$	2,150
Town of Tecumseh		1,545		1,545
		3,695		3,695
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $36, bearing an interest rate of 3.25% due November, 2029		2,354		2,710
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $17, bearing an interest rate of 3.18% due August, 2027		2,247		2,376
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.73% due July, 2028		2,393		2,514

(in thousands of dollars)

11. Long-term debt (continued):

	2023	2022
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.73% due July, 2028	2,393	2,514
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.90% due November, 2028	2,443	2,561
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $39, bearing an interest rate of 2.95% due September, 2029	5,837	6,124
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $26, bearing an interest rate of 2.00% due November, 2030	4,490	4,711
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $31, bearing an interest rate of 2.079% due December, 2030.	5,251	5,505
Fixed rate loan – TD Canada Trust is a 5 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $21, bearing an interest rate of 2.19% due October, 2026.	3,646	3,812
Fixed rate loan – TD Canada Trust is a 2 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $26, bearing an interest rate of 4.94% due December, 2025.	4,000	–
	38,749	36,522
Less: Current portion of long-term debt	3,420	2,512
	$ 35,329	$ 34,010

(in thousands of dollars)

11. Long-term debt (continued):

Approximate long-term principal repayments over the next five years and thereafter are as follows:

2024	$ 3,420
2025	6,498
2026	5,801
2027	4,236
2028	6,918
Thereafter	11,876
	$ 38,749

The loans are secured by a General Security Agreement over the assets of the Corporation.

12. Post-employment benefits:

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2023, the Corporation made employer contributions of $417 to OMERS (2022 - $389) of which $125 (2022 - $117) has been capitalized as part of property, plant and equipment. The Corporation estimates that a contribution of $405 to OMERS will be made during the next fiscal year.

(b) Post-employment benefits other than pension:

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans. The most recent valuation was completed December 31, 2023.

Reconciliation of the obligation	2023	2022
Defined benefit obligation, beginning of year	$ 2,185	$ 2,674
Included in profit or loss		
Current service cost	52	67
Interest cost	107	72
	2,344	2,813
Benefits paid	(180)	(194)
	2,164	2,619
Actuarial gains included in OCI:		
Changes in discount rate	68	(434)
Changes in demographic assumptions	(117)	–
	(49)	(434)
Defined benefit obligation, end of year	$ 2,115	$ 2,185

(in thousands of dollars)

12. Post-employment benefits (continued):

(b) Post-employment benefits other than pension (continued):

Actuarial assumptions	2023	2022
Discount (interest) rate	4.60%	5.00%
General inflation	2.00%	2.00%
Medical Costs	5.50%	6.25%
Dental Costs	4.00%	4.50%

Medical costs are estimated to increase at a rate which declines over time from 5.50% per annum in 2023 to 4.0% by 2037.

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $164. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $189.

A 1% increase in the assumed trend rate would result in the defined benefit obligation increasing by $168. A 1% decrease in the assumed trend rate would result in the defined benefit obligation decreasing by $149.

13. Share capital:

	2023	2022
Authorized:		
Unlimited number of common shares, Class A, voting		
Unlimited number of common shares, Class B, non-voting		
Issued:		
50 common shares, Class A voting, and 15,772,796 common shares, Class B non-voting	$ 15,773	$ 15,773

Dividends

The holders of the common shares are entitled to receive dividends from time to time.

The Corporation paid aggregate dividends in the year on the issued common shares of $0.06873 (2022 - $0.06771) per share. The corporation declared dividends on the issued common shares amounting to $1,100 (2022 - $1,084).

(in thousands of dollars)

14. Revenue:

Revenue consists of the following:

	2023	2022
Revenue from contracts with customers		
Sale of energy	$ 67,435	$ 69,709
Distribution revenue	17,589	17,616
Solar Generation	24	25
Ancillary services revenue	(105)	(12)
Billing services to Municipal shareholders	330	320
Joint use pole rentals	265	249
Other regulatory service charges	354	364
Miscellaneous	143	51
Revenue from other sources		
Deferred revenue recognized from capital contributions	273	221
	$ 86,308	$ 88,543

Sale of energy and distribution revenue consist of the following:

	2023	2022
Residential service	$ 54,478	$ 55,903
General service less than 50KW	7,910	8,957
General service 50 to 4,999KW	22,114	21,732
Intermediate and Embedded distributor	374	357
Unmetered and other	148	376
	$ 85,024	$ 87,325

15. Operating expenses:

	2023	2022
Contract/consulting	$ 1,139	$ 1,174
Materials and supplies	1,356	1,201
Salaries, wages and benefits	3,245	3,218
Cost of billing services for ultimate shareholders	300	291
Post-employment benefit plans	154	140
Vehicles	170	193
Management charges from Parent	1,366	1,144
Bad debts	205	71
Other	1,237	1,265
	$ 9,172	$ 8,697

(in thousands of dollars)

16. Net finance costs:

	2023	2022
Finance income		
Interest income on bank deposits	$ 31	$ 17
Finance costs		
Interest expense on long-term debt	1,048	1,091
Interest expense on customer deposits	36	6
Other	175	88
	1,259	1,185
Net finance costs recognized in profit or loss	$ (1,228)	$ (1,168)

17. Commitments and contingencies:

Contractual Obligations:

General:

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation 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 Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance:

The Corporation 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, 2023, no assessments have been made.

Letter of Credit:

A letter of credit in the amount of $2,900 has been issued by TD Canada Trust to the credit of the Independent Electricity System Operator for the commodity purchases and market services provided. This letter of credit has no term of expiry and is normally renewed annually.

Construction Bonding Agreement:

Essex Energy Corporation, an affiliate, has entered into a construction bonding agreement which has an indemnity requirement that extends to this Corporation for any and all indemnity losses to a maximum limit of $3 million.

(in thousands of dollars)

18. Related party transactions:

(a) Parent and ultimate controlling party:

The sole shareholder of the Corporation is Essex Power Corporation (“EPC”) which is wholly owned by Towns of Amherstburg, LaSalle and Tecumseh, and the Municipality of Leamington (“ultimate parents”). The ultimate parents produce financial statements that are available for public use.

(b) Companies under common control:

Essex Power Corporation owns 100% of Essex Energy Corporation

Essex Energy Corporation owns 100% of Utilismart Corporation

Essex Energy Corporation owns 100% of EE Solar Partners Inc.

Essex Energy Corporation owns 100% of ASI SPE 106 Ltd

Essex Energy Corporation owns 50% of Enertrace Services Ltd.

EE Solar Partners Inc. owns 49% of Muskoka Solar LP

EE Solar Partners Inc. owns 49% of Rosseau Solar LP

Utilismart Corporation owns 100% of Wattsworth Analysis Inc.

(c) Outstanding balances with related parties:

	2023	2022
Balances due to:		
Essex Power Corporation	$ 526	$ 115
Essex Energy Corporation	195	163
Utilismart Corporation	76	32
Wattsworth Analysis Inc.	–	3
Municipality of Leamington	–	81
Town of Tecumseh	1,215	1,167
Town of Amherstburg	1,577	1,666
	$ 3,589	$ 3,227

	2023	2022
Balances due from:		
Essex Energy Corporation	22	27
Town of LaSalle	1	1
Town of Tecumseh	30	18
Town of Amherstburg	32	15
Municipality of Leamington	20	20
	$ 105	$ 81

All balances due from and due to related parties listed above are included within accounts receivable and accounts payable respectively. Amounts are non-interest bearing with repayment terms similar to other trade accounts receivable and accounts payable.

(in thousands of dollars)

18. Related party transactions:

(d) Transactions with parent:

During the year, the corporation paid management fees of $1,366 (2022- $1,144) to its parent.

(e) Transactions with companies under common control:

In the ordinary course of business, the corporation incurred the following transactions with other related parties under common control:

		2023		2022
Sold operating expense services to:				
Essex Energy Corporation	$	170	$	128
Purchased operating expense and solar services from:				
Essex Energy Corporation		885		685
Utilismart Corporation		546		372
Wattsworth Analysis Inc.		–		36

(f) Transactions with ultimate parent:

The Corporation delivers electricity to these entities throughout the year for the electricity needs of the Towns and Municipality. Electricity delivery charges are at prices and under terms approved by the OEB. The Corporation also provides additional services to the Towns and Municipality, including billing and customer care services. The total revenues related to these services for 2023 were $330 (2022 - $320).

(g) Key management personnel:

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members. The compensation paid or payable is as follows:

		2023		2022
Directors' fees	$	22	$	22
Salaries, bonuses and other short-term benefits		484		452
	$	506	$	474

19. Financial instruments and risk management:

Fair value disclosure:

The carrying values of accounts receivable, unbilled revenue, accounts payable and accrued liabilities and bank indebtedness 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.

The fair value of the long-term debt at December 31, 2023 is $26,326 (2022 - $26,286). The fair value is calculated based on the present value of the future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rate used to calculate fair value at December 31, 2023 was 4.5% (2022 - 4.5%). All financial instruments are considered level 1 on the fair value hierarchy.

Financial risks:

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation'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.

(a) 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 Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Towns of Amherstburg, LaSalle, Tecumseh and the Municipality of Leamington. No single customer accounts for a balance in excess of 7% of total electricity 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 profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the loss allowance at December 31, 2023 is $231 (2022 - $125). An impairment loss of $205 (2022 - $71) was recognized during the year.

19. Financial instruments and risk management (continued):

Financial risks (continued):

(a) Credit risk (continued):

The Corporation's credit risk associated with accounts receivable is primarily related to payments from its electricity distribution customers. At December 31, 2023, approximately $236 (2022 - $251) is considered 60 or more days past due. The Corporation has over 33,000 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, 2023, the Corporation holds security deposits in the amount of $396 (2022 - $404).

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation'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.

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $9,000 credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2023, $nil had been drawn under the Corporation's credit facility (2022-$3,173) and is presented in bank indebtedness on the statement of financial position.

The Corporation also has a bilateral facility for $2,900 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which none has been drawn and posted with the IESO during 2023 or 2022.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days. Customer deposits are due on demand. The scheduled repayments associated with long-term debt are described within note 11.

19. Financial instruments and risk management (continued):

(d) Capital disclosures:

The main objectives of the Corporation, 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 Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2023, shareholder's equity amounts to $31,904 (2022 - $31,370) and long-term debt amounts to $38,749 (2022 - $36,522).

Attachment 1-E

EPLC 2022 Audited Financial Statements

Financial Statements of

ESSEX POWERLINES CORPORATION

And Independent Auditor's Report thereon

Year ended December 31, 2023
(Expressed in thousands of dollars)

KPMG LLP
618 Greenwood Centre
3200 Deziel Drive
Windsor, ON N8W 5K8
Canada
Telephone 519 251 3500
Fax 519 251 3530

INDEPENDENT AUDITOR'S REPORT

To the Shareholder of Essex Powerlines Corporation

Opinion

We have audited the financial statements of Essex Powerlines Corporation (the "Entity"), which comprise:

- the statement of financial position as at December 31, 2023
- the statement of comprehensive income for the year then ended
- the statement of changes in 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 Entity as at December 31, 2023, and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting 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 Entity in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled are other ethical 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 Accounting Standards, 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 Entity'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 Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity'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 Entity's internal control.

KPMG

- 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 Entity'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 Entity 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 represent 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

Windsor, Canada
April 18, 2024

ESSEX POWERLINES CORPORATION

Statement of Financial Position
As at December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Note	2023	2022
Assets			
Current assets			
Cash and cash equivalents		$ 839	$ 1
Accounts receivable	4	6,795	6,207
Unbilled revenue		6,627	6,657
Income taxes receivable	8	384	644
Materials and supplies	5	1,691	1,197
Prepaid expenses		329	301
Total current assets		16,665	15,007
Non-current assets			
Property, plant and equipment	6	78,808	72,417
Intangible assets	7	1,922	1,111
Total non-current assets		80,730	73,528
Total assets		97,395	88,535
Regulatory balances	9	8,814	11,605
Total assets and regulatory balances		$ 106,209	$ 100,140

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Financial Position
As at December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Note	2023	2022
Liabilities			
Current liabilities			
Bank indebtedness		$ –	$ 3,221
Accounts payable and accrued liabilities	10	11,601	10,132
Long-term debt due within one year	11	3,420	2,512
Customer deposits		1,903	1,436
Dividend payable		1,100	1,084
Total current liabilities		18,024	18,385
Non-current liabilities			
Long-term debt	11	35,329	34,010
Post-employment benefits	12	2,115	2,185
Deferred revenue		11,634	8,595
Deferred tax liabilities	8	3,681	3,156
Total non-current liabilities		52,759	47,946
Total liabilities		70,783	66,331
Equity			
Share capital	13	15,773	15,773
Retained earnings		14,291	13,793
Accumulated other comprehensive income		1,840	1,804
Total equity		31,904	31,370
Total liabilities and equity		102,687	97,701
Regulatory balances	9	3,522	2,439
Total liabilities, equity and regulatory balances		$ 106,209	$ 100,140

See accompanying notes to the financial statements.

On behalf of the Board:

Michael D Prue Director

Director

ESSEX POWERLINES CORPORATION

Statement of Comprehensive Income
Year ended December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Note	2023	2022
Revenue			
Sale of energy		$ 67,435	$ 69,709
Distribution revenue		17,589	17,616
Solar generation		24	25
Other		1,260	1,193
	14	86,308	88,543
Operating expenses			
Cost of power purchased		66,326	71,029
Operating expenses	15	9,172	8,697
Solar expenses		6	7
Depreciation and amortization		3,615	3,285
Research and development SR&ED ITC reversed		–	19
		79,119	83,037
Income from operating activities		7,189	5,506
Net finance costs	16	(1,228)	(1,168)
Income before income taxes		5,961	4,338
Current tax expense	8	(23)	3
Deferred tax expense	8	512	591
Net income for the year		5,472	3,744
Net movement in regulatory balances, net of tax	9	(3,874)	(1,785)
Net income for the year and net movement in regulatory balances		1,598	1,959
Other comprehensive income			
Items that will not be reclassified to profit or loss:			
Re-measurements of post-employment benefits	12	49	434
Tax on re-measurements		(13)	(115)
Other comprehensive income for the year		36	319
Total comprehensive income for the year		$ 1,634	$ 2,278

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Changes in Equity
Year ended December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	Share capital	Solar Equity	Retained earnings	Accumulated other comprehensive income (Loss)	Total
Balance at January 1, 2022	$ 15,773	$ –	$ 13,251	$ 1,485	$ 30,509
Net income and net movement in regulatory balances	–	–	1,959	–	1,959
Other comprehensive income	–	–	–	319	319
Prior period adjustment	–	–	(333)	–	(333)
Dividends	–	–	(1,084)	–	(1,084)
Balance at December 31, 2022	$ 15,773	$ –	$ 13,793	$ 1,804	$ 31,370
Balance at January 1, 2023	$ 15,773	$ –	$ 13,793	$ 1,804	$ 31,370
Net income and net movement in regulatory balances	–	–	1,598	–	1,598
Other comprehensive income	–	–	–	36	36
Dividends	–	–	(1,100)	–	(1,100)
Balance at December 31, 2023	$ 15,773	$ –	$ 14,291	$ 1,840	$ 31,904

See accompanying notes to the financial statements.

ESSEX POWERLINES CORPORATION

Statement of Cash Flows
Year ended December 31, 2023, with comparative information for 2022
(in thousands of dollars)

	2023	2022
Operating activities		
Net Income and net movement in regulatory balances	$ 1,598	$ 1,959
Adjustments for:		
Depreciation and amortization	3,615	3,285
Amortization of deferred revenue	(273)	(221)
Post-employment benefits	(21)	(55)
Net finance costs	1,228	1,168
Income tax expense	489	594
	6,636	6,730
Change in non-cash operating working capital:		
Accounts receivable	(588)	(756)
Unbilled revenue	30	(946)
Materials and supplies	(494)	(243)
Customer deposits	467	178
Prepaid expenses	(28)	(169)
Accounts payable and accrued liabilities	1,469	(45)
	856	(1,981)
Net movement in regulatory balances	3,874	1,785
Income tax received (paid)	283	(879)
Interest paid	(1,259)	(1,185)
Interest received	31	17
Net cash from operating activities	10,421	4,487
Investing activities		
Purchase of property, plant and equipment	(9,673)	(7,123)
Purchase of intangible assets	(1,196)	(415)
Proceeds on disposal of property, plant and equipment	52	69
Contributions received from customers	3,312	1,634
Net cash used by investing activities	(7,505)	(5,835)
Financing activities		
Dividends paid	(1,084)	(1,068)
Proceeds from long-term debt	4,000	–
Repayment of long-term debt	(1,773)	(1,724)
Net cash from (used by) financing activities	1,143	(2,792)
Change in cash, cash equivalents and bank indebtedness	4,059	(4,140)
Cash and cash equivalents and bank indebtedness, beginning of year	(3,220)	920
Cash, cash equivalents and bank indebtedness, end of year	$ 839	$ (3,220)

See accompanying notes to the financial statements.

1. Reporting entity:

Essex Powerlines Corporation (the “Corporation”) is a rate regulated, municipally owned local distribution company (”LDC”) which is wholly owned by Essex Power Corporation, which in turn, is wholly owned by the shareholders of Essex Power Corporation including the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington and the Town of Tecumseh. The Corporation was incorporated on April 18, 2000 under the *Business Corporations Act* (Ontario), in accordance with the *Electricity Act*. The Corporation is located in Oldcastle, Ontario. The address of the Corporation’s registered office is 2730 Highway 3, Oldcastle, ON N0R 1L0.

The Corporation delivers electricity and related energy services to residential and commercial customers in Amherstburg, LaSalle, Leamington and Tecumseh, under a license issued by the Ontario Energy Board (“OEB”). The Corporation is regulated by the OEB and adjustments to the Corporation’s distribution and power rates require OEB approval.

The financial statements are for the Corporation as at and for the year ended December 31, 2023.

2. Basis of presentation:

(a) Statement of compliance:

The Corporation's financial statements have been prepared in accordance with IFRS Accounting Standards ("IFRS").

The financial statements were approved by the Board of Directors on April 18, 2024.

(b) Basis of measurement:

These financial statements have been prepared on the historical cost basis, unless otherwise stated.

(c) Functional and presentation currency:

These financial statements are presented in Canadian dollars, which is the Corporation's functional currency. All financial information presented in Canadian dollars has been rounded to the nearest thousand.

(d) Use of estimates and judgments:

(i) Assumptions and estimation uncertainty:

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 years affected.

2. Basis of presentation (continued):

(d) Use of estimates and judgments (continued):

(i) Assumptions and estimation uncertainty (continued):

Information about assumptions and estimation uncertainties that have a significant risk of resulting in material adjustment is included in the following notes:

a) Notes 3 (d), (e), (f), 6, 7 – estimation of useful lives of its property, plant and equipment and intangible assets and related impairment tests on long-lived assets

b) Notes 3 (h), 9 – recognition and measurement of regulatory balances

c) Notes 3 (i), 12 – measurement of defined benefit obligations: key actuarial assumptions

d) Note 17 – recognition and measurement of provisions and contingencies

(ii) Judgments:

Information about judgments made in applying accounting policies that have the most significant effects on the amounts recognized in the financial statements is included in the following note:

a) Note 3 (j) – leases: whether an arrangement contains a lease

b) Note 3 (b) – determination of the performance obligation for contributions from customers and the related amortization period

c) Notes 3(h), 9 – recognition of regulatory balances

(e) Rate regulation:

The Corporation 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, such as the Corporation, 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 LDC’s 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.

2. **Basis of presentation (continued):**

(e) Rate regulation (continued):

Rate setting

(i) Distribution Rates:

The Corporation files a "Cost of Service" ("COS") rate application every five years, unless approved for a deferral, under which the OEB establishes the revenues required to recover the forecasted operating costs, including amortization and income taxes, of providing the regulated electricity distribution service and providing a fair return on the Corporation's rate base. The Corporation 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 any registered interveners. Rates are approved based upon the review of evidence and information, including any revisions resulting from that review.

In the intervening years, an Incentive Regulation 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 set by the OEB and a "stretch factor" determined by the relative efficiency of an electricity distributor.

On August 28, 2017, the Corporation submitted a COS rate application to the OEB to change distribution rates effective May 1, 2018. The application was approved by the OEB on October 10, 2018.

On November 1, 2022, the Corporation submitted an IRM Application to the OEB requesting approval to change distribution rates effective May 1, 2023. The IRM Application, which provided a mechanistic and formulaic adjustment to distribution rates and charges, was approved by the OEB on March 23, 2023. The GDP IPI-FDD for 2024 is 3.70%, the Corporation's stretch factor is 0.15% and the productivity factor determined by the OEB is 0%, resulting in a net adjustment of 3.55% to the previous year's rates.

(ii) Electricity Rates:

The OEB sets Ontario electricity prices for low-volume consumers annually each year in 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*.

2. Basis of presentation (continued):

(e) Rate regulation (continued):

(ii) Electricity Rates (continued):

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.

(iii) Retail Transmission Rates:

These are the costs of delivering electricity from generating stations across the Province to local distribution networks. These charges include the costs to build and maintain the transmission lines, towers and poles and operate provincial transmission systems. Retail transmission rates are passed through to the operators of transmission networks and facilities.

(iv) Wholesale Market Service Rates:

These are the costs of administering the wholesale electricity system and maintaining the reliability of the provincial grid and include the costs associated with funding Ministry of Energy conservation and renewable energy programs. The Corporation is billed for the cost of the wholesale electricity system by the Independent Electricity System Operator and passes this cost on to the customer at cost without a mark-up.

3. Material accounting policies:

The accounting policies set out below have been applied consistently in all years presented in these financial statements.

In addition, the Corporation adopted Disclosure of *Accounting Policies (Amendments to IAS 1 and IFRS Practice Statement 2)* from January 1, 2023. The amendments require the disclosure of "material", rather than "significant", accounting policies. Although the amendment did not result in a change to the accounting policies themselves, they impacted the accounting policy information disclosed in Note 3 in certain instances.

(a) Financial instruments:

All financial assets and all financial liabilities 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(f).

The Corporation does not enter into derivative instruments. Hedge accounting has not been used in the preparation of these financial statements.

Cash equivalents may include short-term investments with maturities of three months or less when purchased.

(b) Revenue recognition:

Sale and distribution of electricity

The performance obligations for the sale and distribution of electricity are recognized over time using an output method to measure the satisfaction of the performance obligation. The value of the electricity services transferred to the customer is determined on the basis of cyclical meter readings plus estimated customer usage since the last meter reading date to the end of the year and represents the amount that the Corporation has the right to bill. Revenue includes the cost of electricity supplied, distribution, and any other regulatory charges. 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 Corporation has determined that it is acting as a principal for these electricity charges and, therefore, has presented electricity revenue on a gross basis.

3. Material accounting policies (continued):

(b) Revenue recognition (continued):

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, received from developers are 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 Corporation'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 useful life of the related asset.

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.

Other revenue

Revenue earned from the provision of services is recognized as the service is rendered.

Government grants and the related performance incentive payments under Conservation and Demand Management (“CDM”) programs are recognized as revenue in the year when there is reasonable assurance that the program conditions have been satisfied and the payment will be received.

(c) Materials and supplies:

Materials and supplies, the majority of which is consumed by the Corporation in the provision of its services, is valued at the lower of cost and net realizable value, with cost being determined on a weighted average cost basis, and includes expenditures incurred in acquiring the materials and supplies and other costs incurred in bringing them to their existing location and condition.

3. Material accounting policies (continued):

(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 date of transition to IFRS, 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 contracted services, materials and transportation costs, direct labour, borrowing costs 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 Corporation's borrowings. Qualifying assets are considered to be those that take in excess of nine months to construct.

When parts of an item of PP&E have different useful lives, they are accounted for as separate items (major components) of PP&E.

When items of PP&E are retired or otherwise disposed of, a gain or loss on disposal is determined by comparing the proceeds from disposal, if any, with the carrying amount of the item and is included 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 Corporation 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.

The need to estimate the decommissioning costs at the end of the useful lives of certain assets is reviewed periodically. The Corporation has concluded it does not have any legal or constructive obligation to remove PP&E.

Depreciation is calculated to write off the cost of items of PP&E using the straight-line method over their estimated useful lives, and is generally recognized in profit or loss. Depreciation methods, useful lives, and residual values are reviewed at each reporting date and adjusted prospectively if appropriate. Land is not depreciated. Construction-in-progress assets are not depreciated until the project is complete and the asset is available for use.

The estimated useful lives are as follows:

	Years
Buildings	50
Distribution equipment	15 – 50
Computer hardware and equipment	5 – 10
Office equipment	10
Utility equipment and trucks	7 – 10
Solar generation	20

3. Material accounting policies (continued):

(e) Intangible assets:

Intangible assets used in rate-regulated activities and acquired prior to January 1, 2014 are measured at deemed cost established on the date of transition to IFRS, less accumulated amortization. All other intangible assets are measured at cost.

Computer software that is acquired or developed by the Corporation after January 1, 2014, including software that is not integral to the functionality of equipment purchased which has finite useful lives, is measured at cost less accumulated amortization.

Amortization is recognized in profit or loss on a straight-line basis over the estimated useful lives of intangible assets, other than goodwill, from the date that they are available for use. Amortization methods and useful lives of all intangible assets are reviewed at each reporting date and adjusted prospectively if appropriate. The estimated useful lives are:

	Years
Computer software	5
Land rights	50

(f) Impairment:

(i) Financial assets measured at amortized cost:

A loss allowance for expected credit losses on financial assets measured at amortized cost is recognized at the reporting date. The loss allowance is measured at an amount equal to the lifetime expected credit losses for the asset.

(ii) Non-financial assets:

The carrying amounts of the Corporation's non-financial assets, other than 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.

3. **Material accounting policies (continued):**

(f) Impairment (continued):

(ii) Non-financial assets (continued) :

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" or “CGU”). The recoverable amount of an asset or CGU 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.

The goodwill acquired in a business combination, for the purpose of impairment testing, is allocated to CGUs that are expected to benefit from the synergies of the combination.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. They are allocated first to reduce the carrying amount of any goodwill allocated to the CGU, and then to reduce the carrying amounts of the other assets in the CGU on a prorated basis, if applicable.

An impairment loss in respect of goodwill is not reversed. For other assets, 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 or amortization, if no impairment loss had been recognized.

For the regulated business, the carrying costs of most of the Corporation's non-financial assets are included in rate base (the aggregate of approved investment in PP&E and intangible assets, excluding construction in progress, less accumulated depreciation and amortization and unamortized capital contributions from customers, plus an allowance for working capital) where they earn an OEB-approved rate of return. Asset carrying values and the related return are recovered through approved rates. As a result, such assets are only tested for impairment in the event that the OEB disallows recovery, in whole or in part, or if such a disallowance is judged to be probable.

(g) Customer deposits:

Customer deposits represent cash deposits from electricity distribution customers and retailers to guarantee the payment of energy bills and deposits. Interest is paid on customer deposits. Deposits are also received for planned chargeable work. No interest is paid on these deposits.

Deposits are refundable to customers who demonstrate an acceptable level of credit risk as determined by the Corporation in accordance with policies set out by the OEB or upon termination of their electricity distribution service.

3. Material accounting policies (continued):

(h) Regulatory balances:

In January 2014, the IASB issued IFRS 14 as an interim standard giving entities conducting rate-regulated activities the option of recognizing regulatory balances in accordance with its previous Generally Accepted Accounting Principles ("GAAP") when it adopts IFRS. An entity is permitted to apply the requirements of this standard in its first IFRS financial statements if it conducts rate-regulated activities and recognized amounts that qualify as regulatory deferral account balances in its financial statements in accordance with its previous GAAP. IFRS 14 is effective for periods beginning on or after January 1, 2016, however, early application was permitted. The Corporation elected to apply this Standard in its first IFRS financial statements as at December 31, 2015.

Regulatory deferral account debit balances represent costs incurred in excess of amounts billed to the customer at OEB approved rates. Regulatory deferral account credit balances represent amounts billed to the customer at OEB approved rates in excess of costs incurred by the Corporation.

Regulatory deferral account debit balances are recognized if it is probable that future billings in an amount at least equal to the deferred cost will result from inclusion of that cost in allowable costs for rate-making purposes. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or other comprehensive income ("OCI"). When the customer is billed at rates approved by the OEB for the recovery of the deferred costs, the customer billings are recognized in revenue.

When the Corporation is required to refund amounts to ratepayers in the future, the Corporation recognizes a regulatory deferral account credit balance. The offsetting amount is recognized in net movement in regulatory balances in profit or loss or OCI. When the amounts are returned to the customer at rates approved by the OEB the amounts are recognized as a reduction of revenue.

The probability of recovery of the regulatory deferral account debit balances is assessed annually based upon the likelihood that the OEB will approve the change in rates to recover the balance. The assessment of likelihood of recovery is based upon previous decisions made by the OEB for similar circumstances, policies or guidelines issued by the OEB, etc. Any resulting impairment loss is recognized in profit or loss in the year incurred.

3. **Material accounting policies (continued):**

(i) Post-employment benefits:

(i) Pension plan:

The Corporation provides a pension plan for some of its full-time employees through Ontario Municipal Employees Retirement System (“OMERS”). OMERS is a multi-employer pension plan that provides pensions for employees of Ontario municipalities, local boards and public utilities. OMERS is a contributory defined benefit pension plan, which is financed by equal contributions from participating employers and employees, and by investment earnings. To the extent that the plan finds itself in an under-funded position, additional contribution rates may be assessed to participating employers and members.

OMERS is a defined benefit plan. However, as OMERS does not segregate its pension asset and liability information by individual employers, there is insufficient information available to enable the Corporation to directly account for the plan. Consequently, the plan has been accounted for as a defined contribution plan. The Corporation is not responsible for any other contractual obligations other than the contributions. Obligations for contributions to defined contribution pension plans are recognized as an employee benefit expense in profit or loss when they are due.

(ii) Post-employment benefits, other than pension:

The Corporation provides some of its retired employees with life insurance and medical benefits beyond those provided by government sponsored plans.

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.

(j) Leased assets:

At inception of a contract, the Corporation assess whether the contract is or contains a lease. A contract is determined to contain a lease if it provides the Corporation with the right to control the use of an identified asset for a period of time in exchange for consideration. Contracts determined to contain a lease are accounted for as leases. For leases and contracts that contain a lease, the Corporation recognizes a right-of-use asset and a lease liability at the lease commencement date. The right-of-use asset is initially measured at cost which comprises the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received.

3. Material accounting policies (continued):

(j) Leased assets (continued):

The right-of-use asset is subsequently depreciated using the straight-line method from the commencement date to the earlier of the end of the useful life of the right-of-use asset or the end of the lease term. The estimated useful lives of right-of-use assets are determined on the same basis as those of property, plant and equipment. Subsequent to initial recognition, the right-of-use asset is recognized at cost less any accumulated depreciation and any accumulated impairment losses, adjusted for certain remeasurements of the corresponding lease liability.

The lease liability is initially measured at the present value of lease payments plus the present value of lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease, or if that rate cannot be readily determined, the Corporation's incremental borrowing rate.

The lease liability is subsequently measured at amortized cost using the effective interest method. It is remeasured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Corporation's estimate of the amount expected to be payable under a residual value guarantee, or if the Corporation changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is remeasured in this way, a corresponding adjustment is made to the carrying amount of the right-of-use asset, or is recorded in profit or loss if the carrying amount of the right-of-use asset has been reduced to zero.

The Corporation has elected not to recognize right-of-use assets and lease liabilities for leases that have a lease term of 12 months or less or for leases of low value assets. The Corporation 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):

(k) Income taxes:

The income tax expense comprises current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case, it is recognized in equity.

The Corporation is 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 Corporation makes payments in lieu of corporate taxes to the Ontario Electricity Financial Corporation ("OEFC"). These payments are calculated in accordance with the rules for computing taxable income and taxable capital and other relevant amounts contained in the Tax Acts as modified by the *Electricity Act*, 1998, and related regulations. Payments in lieu of taxes and payments under the Tax Acts are collectively referred to as income taxes.

Current tax comprises the expected tax payable or receivable on the taxable income or loss 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 tax is recognized in respect of temporary differences between the tax basis of assets and liabilities and their carrying amounts for accounting purposes. Deferred tax assets are recognized for unused tax losses, unused tax credits and deductible temporary differences to the extent that it is probable that future taxable profits will be available against which they can be used. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, using tax rates enacted or substantively enacted, at the reporting date.

3. Significant accounting policies (continued):

(l) Accounting standards issued but not yet effective:

The following standards which are not yet effective for the year ended December 31, 2023, have not been applied in preparing these financial statements.

(i) Classification of Liabilities as Current or Non-Current (Amendments to IAS 1)

On January 23, 2020, the IASB issued amendments to IAS 1 *Presentation of Financial Statements*, to clarify the classification of liabilities as current or non-current.

On October 31, 2022, the IASB issued *Non-current Liabilities with Covenants (Amendments to IAS 1)* (the 2022 amendments), to improve the information a company provides about long-term debt with covenants.

The 2020 amendments and the 2022 amendments (collectively “the Amendments”) are effective for annual periods beginning on or after January 1, 2024.

(ii) Lease Liability in a Sale and Leaseback (Amendments to IFRS 16 Leases)

On September 22, 2022, the IASB issued *Lease Liability in a Sale and Leaseback (Amendments to IFRS 16).*

The amendments are effective for annual periods beginning on or after January 1, 2024.

(iii) Supplier Finance Arrangements (Amendments to IAS 7 and IFRS 7)

On May 25, 2023, the IASB issued amendments to IAS 7 *Statement of Cash Flows* and IFRS 7 *Financial Instruments: Disclosures.*

The amendments are effective for annual periods beginning on or after January 1, 2024.

(iv) Lack of exchangeability (Amendments to IAS 21)

On August 15, 2023, the IASB issued amendments to IAS 21 *The Effects of Changes in Foreign Exchange Rates* to clarify when a currency is exchangeable into another currency and how a company estimates a spot rate when a currency lacks exchangeability.

The amendments apply for annual reporting periods beginning on or after January 1, 2025, with earlier application permitted.

The Corporation has assessed the potential impacts on its financial statements, and determined that the future pronouncements will not have a material impact on the Corporation.

(in thousands of dollars)

4. Accounts receivable:

	2023	2022
Trade receivables	$ 6,222	$ 5,650
Due from related parties	115	81
Other receivables	624	552
Billable work	65	49
Less:		
Loss allowance	(231)	(125)
	$ 6,795	$ 6,207

5. Materials and supplies:

Amount written down due to obsolescence in 2023 was $nil (2022 - $nil).

6. Property, plant and equipment:

	Land and buildings	Distribution equipment	Other fixed assets	Construction in-Progress	Total
Cost					
Balance at January 1, 2023	$ 3,223	$ 82,342	$ 6,380	$ 626	$ 92,571
Additions	730	7,976	1,091	–	9,797
Disposals/retirements	(20)	(70)	(77)	–	(167)
Balance at December 31, 2023	$ 3,933	$ 90,248	$ 7,394	$ 626	$ 102,201
Balance at January 1, 2022	$ 2,998	$ 76,444	$ 5,658	$ 640	$ 85,740
Additions	225	5,989	799	110	7,123
Disposals/retirements	–	(91)	(77)	–	(168)
Balance at December 31, 2022	$ 3,223	$ 82,342	$ 6,380	$ 750	$ 92,695
Accumulated depreciation					
Balance at January 1, 2023	$ 401	$ 16,482	$ 3,395	$ –	$ 20,278
Depreciation	68	2,538	624	–	3,230
Disposals/retirements	(1)	(37)	(77)	–	(115)
Balance at December 31, 2023	$ 468	$ 18,983	$ 3,942	$ –	$ 23,393
Balance at January 1, 2022	$ 342	$ 14,140	$ 2,874	$ –	$ 17,356
Depreciation	59	2,376	586	–	3,021
Disposals/retirements	–	(34)	(65)	–	(99)
Balance at December 31, 2022	$ 401	$ 16,482	$ 3,395	$ –	$ 20,278
Carrying amounts					
At December 31, 2023	$ 3,465	$ 71,265	$ 3,452	$ 626	$ 78,808
At December 31, 2022	$ 2,822	$ 65,860	$ 2,985	$ 750	$ 72,417

At December 31, 2023 property plant and equipment with a carrying amount of $78,808 (2022 - $72,417) are subject to a general security agreement.

There were no borrowing costs capitalized as part of the cost of property, plant and equipment in 2023 or 2022.

(in thousands of dollars)

7. Intangible assets:

	Computer software	Land rights	Total
Cost			
Balance at January 1, 2023	$ 2,072	$ 238	$ 2,310
Additions	1,196	–	1,196
Balance at December 31, 2023	$ 3,268	$ 238	$ 3,506
Balance at January 1, 2022	$ 1,657	$ 238	$ 1,895
Additions	415	–	415
Balance at December 31, 2022	$ 2,072	$ 238	$ 2,310
Accumulated amortization			
Balance at January 1, 2023	$ 1,158	$ 41	$ 1,199
Amortization	380	5	385
Balance at December 31, 2023	$ 1,538	$ 46	$ 1,584
Balance at January 1, 2022	$ 899	$ 36	$ 935
Amortization	259	5	264
Balance at December 31, 2022	$ 1,158	$ 41	$ 1,199
Carrying amounts			
At December 31, 2023	$ 1,730	$ 192	$ 1,922
At December 31, 2022	$ 914	$ 197	$ 1,111

(in thousands of dollars)

8. Income tax expense:

Income tax expense is comprised of:

	2023	2022
Current tax expense	$ (23)	$ 3
Deferred tax expense	512	591
	$ 489	$ 594

Reconciliation of effective tax rate:

	2023	2022
Income before taxes	$ 5,961	$ 4,338
Canada and Ontario statutory Income tax rates	26.5%	26.5%
Expected tax expense on income at statutory rates	1,579	1,149
Increase in income taxes resulting from:		
Non-taxable amounts	92	103
Net movement in regulatory balances	(514)	(656)
Other items	(668)	(2)
Income tax expense	$ 489	$ 594
Effective income tax rate	8.2%	13.7%

Significant components of the Corporation's deferred tax balances:

	2023	2022
Deferred tax assets (liabilities) consist of the following:		
Property, plant, equipment (regulated)	$ (4,704)	$ (3,812)
Post-employment benefits	560	579
Total deferred tax liabilities to be realized by customers	(4,144)	(3,233)
Deferred tax liabilities from non-regulated solar assets	(18)	(20)
Other deferred tax assets	481	97
	$ (3,681)	$ (3,156)

9. Regulatory balances:

The Corporation has determined that certain debit and credit balances arising from rate-regulated activities qualify for regulatory accounting treatment in accordance with IFRS 14 and the OEB's prescribed accounting procedures for electricity distributors. The regulatory balances are comprised of regulatory debit balances of $8,814 (2022 - $11,605) and regulatory credit balances of $3,522 (2022 - $2,439) for a net regulatory asset of $5,292 (2022 - $9,166).

Regulatory balances attract interest at OEB prescribed rates, which are based on Bankers' Acceptances three-month rate plus a spread of 25 basis points, with the exception of the tax balances. In 2023, the rate was 4.73% for the period January to March, 4.98% for the period April to September and 5.49% for the period for the period October to December.

The regulatory balances for the Corporation consist of the following:

(a) Settlement Variance:

This account includes the variances between amounts charged by the Corporation, based on regulated rates, and the corresponding cost of electricity and non-competitive electricity service costs incurred by the Corporation such as commodity charges, retail transmission rates and wholesale market services charges. The Corporation has deferred the variances and related recoveries in accordance with the criteria set out in the accounting principles prescribed by the OEB. This account also includes variances between the amounts approved for disposition by the OEB and the amounts collected or paid through OEB approved rate riders.

Settlement variances are reviewed annually as part of a COS or IRM application submitted to the OEB and a request for disposition is made if the aggregate of the settlement accounts exceeds the OEB's prescribed materiality level.

(b) Regulatory settlement accounts:

Regulatory settlement accounts include those settlement variances for which the OEB has approved for disposition. On March 23, 2023, the OEB issued a final rate order approving 2023 rates effective May 1, 2023.

(c) Customer Liability for Deferred Taxes:

The OEB requires the Corporation to estimate its income taxes when it files a COS application to set rates. As a result, the Corporation has recognized a regulatory deferral account for the amount of deferred taxes that will ultimately be recovered from or paid back to its customers. This balance will fluctuate as the Corporation's deferred tax balance fluctuates.

(in thousands of dollars)

9. Regulatory balances (continued):

(d) Other:

This deferral account includes the allowable costs associated with the transition to IFRS and other miscellaneous regulatory accounts.

Reconciliation of the carrying amount for each class of regulatory balances:

Regulatory deferral account debit balances	January 1, 2023	Additions/ transfers	Recovery/ reversal	December 31, 2023	Remaining years
Group 1 deferred accounts	$ 5,875	$ (1,944)	$ (257)	$ 3,674	1
Regulatory transition to IFRS	148	–	–	148	1-2
Regulatory settlement account	2,879	25	(1,423)	1,481	1
Other regulatory accounts	163	294	–	457	1-2
Income tax	2,540	514	–	3,054	1-2
	$ 11,605	$ (1,111)	$ (1,680)	$ 8,814	

Regulatory deferral account debit balances	January 1, 2022	Additions/ transfers	Recovery/ reversal	December 31, 2022	Remaining years
Group 1 deferred accounts	$ 6,220	$ 1,524	$ (1,869)	$ 5,875	1-2
Regulatory transition to IFRS	148	–	–	148	3
Regulatory settlement account	5,738	34	(2,893)	2,879	1-2
Other regulatory accounts	129	34	–	163	3
Income tax	1,884	656	–	2,540	3
	$ 14,119	$ 2,248	$ (4,762)	$ 11,605	

Regulatory deferral account credit balances	January 1, 2023	Additions/ transfers	Recovery/ reversal	December 31, 2023	Remaining years
Group 1 deferred accounts	$ (244)	$ 797	$ (808)	$ (255)	1
Regulatory settlement account	(1,670)	1,736	(2,681)	(2,615)	1
Other regulatory accounts	(525)	(127)	–	(652)	1-2
	$ (2,439)	$ 2,406	$ (3,489)	$ (3,522)	

Regulatory deferral account credit balances	January 1, 2022	Additions/ transfers	Recovery/ reversal	December 31, 2022	Remaining years
Group 1 deferred accounts	$ (234)	$ (104)	$ 94	$ (244)	1-2
Regulatory settlement account	(2,506)	(273)	1,109	(1,670)	1-2
Other regulatory accounts	(428)	(97)	–	(525)	3
	$ (3,168)	$ (474)	$ 1,203	$ (2,439)	

The “Additions/Transfers” column consists of new additions to regulatory balances (for both debits and credits). The “Recovery/Reversal” column consists of amounts collected or paid through rate riders or transactions reversing an existing regulatory balance to recover. Recoveries and reversals occur as a result of the approval of an application. There were no reversals of regulatory balances for the year ended December 31, 2023.

(in thousands of dollars)

10. Accounts payable and accrued liabilities:

	2023	2022
Accounts payable – energy purchases	$ 6,048	$ 5,488
Payroll payable	258	301
Due to related parties	868	453
Water and waste water billings due to Ultimate Shareholders	2,730	2,774
Other accounts payable and accrued liabilities	1,697	1,116
	$ 11,601	$ 10,132

11. Long-term debt:

	2023	2022
Related party long-term loan payable is repayable as approved by the Board of Directors not to exceed 20% of the principal lending amount if funds are available as determined each March. Interest is payable at a stated interest rate of 4.0% (2022 - 3.8%). The agreement expires December 31, 2027. The debt is owing to two of the four shareholders of the parent company as follows:		
Municipality of Leamington	$ 2,150	$ 2,150
Town of Tecumseh	1,545	1,545
	3,695	3,695
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $36, bearing an interest rate of 3.25% due November, 2029	2,354	2,710
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $17, bearing an interest rate of 3.18% due August, 2027	2,247	2,376
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.73% due July, 2028	2,393	2,514

(in thousands of dollars)

11. Long-term debt (continued):

		2023		2022
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.73% due July, 2028		2,393		2,514
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $18, bearing an interest rate of 3.90% due November, 2028		2,443		2,561
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $39, bearing an interest rate of 2.95% due September, 2029		5,837		6,124
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $26, bearing an interest rate of 2.00% due November, 2030		4,490		4,711
Fixed rate loan – TD Canada Trust is a 10 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $31, bearing an interest rate of 2.079% due December, 2030.		5,251		5,505
Fixed rate loan – TD Canada Trust is a 5 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $21, bearing an interest rate of 2.19% due October, 2026.		3,646		3,812
Fixed rate loan – TD Canada Trust is a 2 year term loan with a 20 year amortization schedule, repayable in blended monthly payments of $26, bearing an interest rate of 4.94% due December, 2025.		4,000		–
		38,749		36,522
Less: Current portion of long-term debt		3,420		2,512
	$	35,329	$	34,010

(in thousands of dollars)

11. Long-term debt (continued):

Approximate long-term principal repayments over the next five years and thereafter are as follows:

2024	$	3,420
2025		6,498
2026		5,801
2027		4,236
2028		6,918
Thereafter		11,876
	$	38,749

The loans are secured by a General Security Agreement over the assets of the Corporation.

12. Post-employment benefits:

(a) OMERS pension plan

The Corporation provides a pension plan for its employees through OMERS. The plan is a multi-employer, contributory defined pension plan with equal contributions by the employer and its employees. In 2023, the Corporation made employer contributions of $417 to OMERS (2022 - $389) of which $125 (2022 - $117) has been capitalized as part of property, plant and equipment. The Corporation estimates that a contribution of $405 to OMERS will be made during the next fiscal year.

(b) Post-employment benefits other than pension:

The Corporation pays certain medical and life insurance benefits on behalf of some of its retired employees. The Corporation recognizes these post-employment benefits in the year in which employees' services were rendered. The Corporation is recovering its post-employment benefits in rates based on the expense and re-measurements recognized for post-employment benefit plans. The most recent valuation was completed December 31, 2023.

Reconciliation of the obligation		2023		2022
Defined benefit obligation, beginning of year	$	2,185	$	2,674
Included in profit or loss				
Current service cost		52		67
Interest cost		107		72
		2,344		2,813
Benefits paid		(180)		(194)
		2,164		2,619
Actuarial gains included in OCI:				
Changes in discount rate		68		(434)
Changes in demographic assumptions		(117)		–
		(49)		(434)
Defined benefit obligation, end of year	$	2,115	$	2,185

(in thousands of dollars)

12. Post-employment benefits (continued):

(b) Post-employment benefits other than pension (continued):

Actuarial assumptions	2023	2022
Discount (interest) rate	4.60%	5.00%
General inflation	2.00%	2.00%
Medical Costs	5.50%	6.25%
Dental Costs	4.00%	4.50%

Medical costs are estimated to increase at a rate which declines over time from 5.50% per annum in 2023 to 4.0% by 2037.

A 1% increase in the assumed discount rate would result in the defined benefit obligation decreasing by $164. A 1% decrease in the assumed discount rate would result in the defined benefits obligation increasing by $189.

A 1% increase in the assumed trend rate would result in the defined benefit obligation increasing by $168. A 1% decrease in the assumed trend rate would result in the defined benefit obligation decreasing by $149.

13. Share capital:

	2023	2022
Authorized:		
Unlimited number of common shares, Class A, voting		
Unlimited number of common shares, Class B, non-voting		
Issued:		
50 common shares, Class A voting, and 15,772,796 common shares, Class B non-voting	$ 15,773	$ 15,773

Dividends

The holders of the common shares are entitled to receive dividends from time to time.

The Corporation paid aggregate dividends in the year on the issued common shares of $0.06873 (2022 - $0.06771) per share. The corporation declared dividends on the issued common shares amounting to $1,100 (2022 - $1,084).

(in thousands of dollars)

14. Revenue:

Revenue consists of the following:

	2023	2022
Revenue from contracts with customers		
Sale of energy	$ 67,435	$ 69,709
Distribution revenue	17,589	17,616
Solar Generation	24	25
Ancillary services revenue	(105)	(12)
Billing services to Municipal shareholders	330	320
Joint use pole rentals	265	249
Other regulatory service charges	354	364
Miscellaneous	143	51
Revenue from other sources		
Deferred revenue recognized from capital contributions	273	221
	$ 86,308	$ 88,543

Sale of energy and distribution revenue consist of the following:

	2023	2022
Residential service	$ 54,478	$ 55,903
General service less than 50KW	7,910	8,957
General service 50 to 4,999KW	22,114	21,732
Intermediate and Embedded distributor	374	357
Unmetered and other	148	376
	$ 85,024	$ 87,325

15. Operating expenses:

	2023	2022
Contract/consulting	$ 1,139	$ 1,174
Materials and supplies	1,356	1,201
Salaries, wages and benefits	3,245	3,218
Cost of billing services for ultimate shareholders	300	291
Post-employment benefit plans	154	140
Vehicles	170	193
Management charges from Parent	1,366	1,144
Bad debts	205	71
Other	1,237	1,265
	$ 9,172	$ 8,697

(in thousands of dollars)

16. Net finance costs:

		2023		2022
Finance income				
Interest income on bank deposits	$	31	$	17
Finance costs				
Interest expense on long-term debt		1,048		1,091
Interest expense on customer deposits		36		6
Other		175		88
		1,259		1,185
Net finance costs recognized in profit or loss	$	(1,228)	$	(1,168)

17. Commitments and contingencies:

Contractual Obligations:

General:

From time to time, the Corporation is involved in various litigation matters arising in the ordinary course of its business. The Corporation 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 Corporation's financial position, results of operations or its ability to carry on any of its business activities.

General Liability Insurance:

The Corporation 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, 2023, no assessments have been made.

Letter of Credit:

A letter of credit in the amount of $2,900 has been issued by TD Canada Trust to the credit of the Independent Electricity System Operator for the commodity purchases and market services provided. This letter of credit has no term of expiry and is normally renewed annually.

Construction Bonding Agreement:

Essex Energy Corporation, an affiliate, has entered into a construction bonding agreement which has an indemnity requirement that extends to this Corporation for any and all indemnity losses to a maximum limit of $3 million.

(in thousands of dollars)

18. Related party transactions:

(a) Parent and ultimate controlling party:

The sole shareholder of the Corporation is Essex Power Corporation ("EPC") which is wholly owned by Towns of Amherstburg, LaSalle and Tecumseh, and the Municipality of Leamington ("ultimate parents"). The ultimate parents produce financial statements that are available for public use.

(b) Companies under common control:

Essex Power Corporation owns 100% of Essex Energy Corporation

Essex Energy Corporation owns 100% of Utilismart Corporation

Essex Energy Corporation owns 100% of EE Solar Partners Inc.

Essex Energy Corporation owns 100% of ASI SPE 106 Ltd

Essex Energy Corporation owns 50% of Enertrace Services Ltd.

EE Solar Partners Inc. owns 49% of Muskoka Solar LP

EE Solar Partners Inc. owns 49% of Rosseau Solar LP

Utilismart Corporation owns 100% of Wattsworth Analysis Inc.

(c) Outstanding balances with related parties:

	2023	2022
Balances due to:		
Essex Power Corporation	$ 526	$ 115
Essex Energy Corporation	195	163
Utilismart Corporation	76	32
Wattsworth Analysis Inc.	–	3
Municipality of Leamington	–	81
Town of Tecumseh	1,215	1,167
Town of Amherstburg	1,577	1,666
	$ 3,589	$ 3,227

	2023	2022
Balances due from:		
Essex Energy Corporation	22	27
Town of LaSalle	1	1
Town of Tecumseh	30	18
Town of Amherstburg	32	15
Municipality of Leamington	20	20
	$ 105	$ 81

All balances due from and due to related parties listed above are included within accounts receivable and accounts payable respectively. Amounts are non-interest bearing with repayment terms similar to other trade accounts receivable and accounts payable.

(in thousands of dollars)

18. Related party transactions:

(d) Transactions with parent:

During the year, the corporation paid management fees of $1,366 (2022- $1,144) to its parent.

(e) Transactions with companies under common control:

In the ordinary course of business, the corporation incurred the following transactions with other related parties under common control:

		2023		2022
Sold operating expense services to:				
Essex Energy Corporation	$	170	$	128
Purchased operating expense and solar services from:				
Essex Energy Corporation		885		685
Utilismart Corporation		546		372
Wattsworth Analysis Inc.		–		36

(f) Transactions with ultimate parent:

The Corporation delivers electricity to these entities throughout the year for the electricity needs of the Towns and Municipality. Electricity delivery charges are at prices and under terms approved by the OEB. The Corporation also provides additional services to the Towns and Municipality, including billing and customer care services. The total revenues related to these services for 2023 were $330 (2022 - $320).

(g) Key management personnel:

The key management personnel of the Corporation have been defined as members of its board of directors and executive management team members. The compensation paid or payable is as follows:

		2023		2022
Directors' fees	$	22	$	22
Salaries, bonuses and other short-term benefits		484		452
	$	506	$	474

19. Financial instruments and risk management:

Fair value disclosure:

The carrying values of accounts receivable, unbilled revenue, accounts payable and accrued liabilities and bank indebtedness 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.

The fair value of the long-term debt at December 31, 2023 is $26,326 (2022 - $26,286). The fair value is calculated based on the present value of the future principal and interest cash flows, discounted at the current rate of interest at the reporting date. The interest rate used to calculate fair value at December 31, 2023 was 4.5% (2022 - 4.5%). All financial instruments are considered level 1 on the fair value hierarchy.

Financial risks:

The Corporation understands the risks inherent in its business and defines them broadly as anything that could impact its ability to achieve its strategic objectives. The Corporation’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.

(a) 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 Corporation, such as accounts receivable, expose it to credit risk. The Corporation earns its revenue from a broad base of customers located in the Towns of Amherstburg, LaSalle, Tecumseh and the Municipality of Leamington. No single customer accounts for a balance in excess of 7% of total electricity 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 profit or loss. Subsequent recoveries of receivables previously provisioned are credited to profit or loss. The balance of the loss allowance at December 31, 2023 is $231 (2022 - $125). An impairment loss of $205 (2022 - $71) was recognized during the year.

19. Financial instruments and risk management (continued):

Financial risks (continued):

(a) Credit risk (continued):

The Corporation's credit risk associated with accounts receivable is primarily related to payments from its electricity distribution customers. At December 31, 2023, approximately $236 (2022 - $251) is considered 60 or more days past due. The Corporation has over 33,000 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, 2023, the Corporation holds security deposits in the amount of $396 (2022 - $404).

(b) Market risk:

Market risks primarily refer to the risk of loss resulting from changes in commodity prices, foreign exchange rates, and interest rates. The Corporation currently does not have any material commodity or foreign exchange risk. The Corporation is exposed to fluctuations in interest rates as the regulated rate of return for the Corporation'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.

(c) Liquidity risk:

The Corporation monitors its liquidity risk to ensure access to sufficient funds to meet operational and investing requirements. The Corporation's objective is to ensure that sufficient liquidity is on hand to meet obligations as they fall due while minimizing interest exposure. The Corporation has access to a $9,000 credit facility and monitors cash balances daily to ensure that a sufficient level of liquidity is on hand to meet financial commitments as they become due. As at December 31, 2023, $nil had been drawn under the Corporation's credit facility (2022-$3,173) and is presented in bank indebtedness on the statement of financial position.

The Corporation also has a bilateral facility for $2,900 (the "LC" facility) for the purpose of issuing letters of credit mainly to support the prudential requirements of the IESO, of which none has been drawn and posted with the IESO during 2023 or 2022.

The majority of accounts payable, as reported on the statement of financial position, are due within 30 days. Customer deposits are due on demand. The scheduled repayments associated with long-term debt are described within note 11.

19. Financial instruments and risk management (continued):

(d) Capital disclosures:

The main objectives of the Corporation, 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 Corporation's definition of capital includes shareholder's equity and long-term debt. As at December 31, 2023, shareholder's equity amounts to $31,904 (2022 - $31,370) and long-term debt amounts to $38,749 (2022 - $36,522).

Attachment 1-G

EPLC Annual Report

Transforming the Future of Energy. Today.

ANNUAL 2022 REPORT

Corporate **Philosophy**

Our Mission

Essex Power Corporation is a dynamic energy company that provides safe, reliable, and economical energy supply and services to our customers. Our commitment to innovation, performance management, and leading by example has built the foundation at Essex Power and our affiliates to establish a diverse set of energy products and services that are valued by our customers.

At Essex Power, Your Power is Our Priority.

Our Vision

Essex Power Corporation's vision is to be an Energy Provider that utilizes "best in class" people, processes, and technology to lead the marketplace in sustainable energy solutions. Our customers will receive the greatest value by integrating an economic and environmental balance to the products and services we will deliver to them. As an Energy Provider, we will be a community leader in ensuring that environmental stewardship is a vital component of our services to increase customer awareness of proper energy utilization and management.

If you have questions regarding the content of this annual report please contact us at **info@essexpower.ca**

Table of **Contents**

Board Chair & CEO
Executive Summary

2022 was a complex year as the world, industry and EPC began a transition back to 'normal.' While fortunate the pandemic has subsided, its effects will remain for years. Supply chain issues, access to qualified labour, the "great resignation", inflation and technological disruption have all changed how businesses operate. Layer in extreme weather and decarbonization efforts, the utility industry is further complicated.

The Essex Power Group continued to transform and was able to address the above and also challenges faced by LDCs in 2022 and to provide a new framework for its continued growth and effective regulation. It focuses on improving operational efficiency, expanding product offerings, and strengthening relationships with stakeholders to maintain a competitive edge in the market. The ultimate goal is to meet the evolving needs of the industry while ensuring compliance with regulations and maintaining high standards of quality and service.

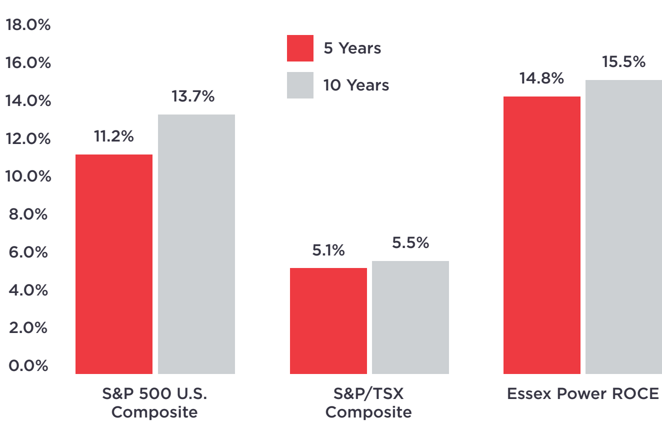
The focus on transforming Essex Powerlines (EPL) from a 'poles and wires' company to an Energy Management Services provider will lead energy transformation in Ontario and beyond. With the award of the joint IESO/OEB Grid Innovation Fund, EPL sits at the centre of change for where the industry needs to go by enabling a multi-directional flow of electrons and meeting the enhanced expectations of customers and stakeholders.

PowerShare officially launched in March 2022. This Distrubution System Operator (DSO) model is focused on maximizing the benefits of existing assets through optimizing their use through data analytics and modelling in order to allow Distributed Energy Resources (DERs) to be connected to the distribution system. This is analogous to the Uber of Energy… taking an asset that typically sits idle and extend its benefit for the greater good… in Uber's case, using a vehicle that would normally sit idle and provide additional transportation capacity to a region. The asset owner takes a standard vehicle cost and turns it into revenue and the rider gets extreme convenience and enhance rider experience for a fair price.

Thanks to Essex Power's robust financial performance in 2022, we were able to simultaneously reinvest in our infrastructure and deliver a fair and equitable return to our valued Shareholders through dividends.. Our 5 and 10 year average returns on common equity beat the two S&P referenced market returns. The overall year 2022 corporate return on common equity was 13.8% which is close to the past five-year average return of 14.8%. Following a four-year stable dividend pattern, Essex Power declared a larger $1,827,709 common share dividend for year 2022 and plans to continue increasing the common share dividends annually. Over the past five years, Essex Power's consistent dividend payouts have provided our Shareholders with the means to invest in local initiatives and sustainable communities. Essex

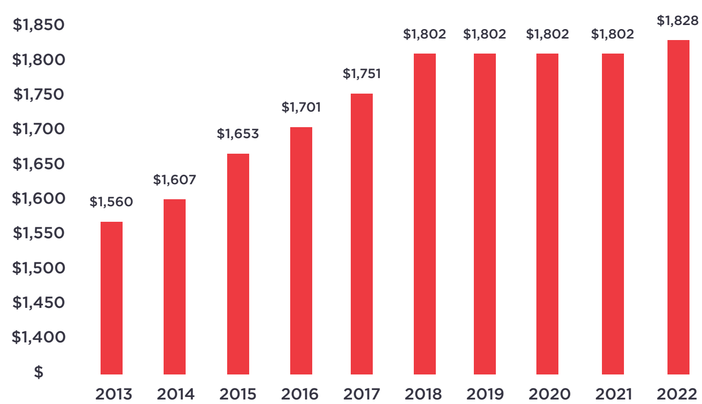
Essex Power **Performance Report**

Average Annual Return on Common Equity



EPC **Annual Dividends** Declared

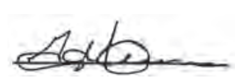
Thousands



Power remains dedicated to upholding the highest standards in serving our Shareholders' communities, with unwavering commitment at every level of our organization. This commitment is evident in our Board's guidance and support, our Executives' strong leadership, and the hard work, dedication, and expertise of our staff. By being a trusted and local service provider, forging valuable relationships with our customers, and fostering strong partnerships with each of our Shareholders, Essex Power is poised to embrace the exciting changes in the electricity market and confidently expand into the future.

We continue to focus on supporting our communities and stay thankful for the ability to contribute back where we can. The current economy continues to affect families, businesses and our ability to support local groups, schools and communities is key to our social principles. We must continue to hold these principles central to our decision-making criteria.

Essex Power and The Three Fires Group have created a unique partnership, working together to provide regional energy solutions that are guided by principals of stewardship for the land, air and water. This partnership will benefit both organizations and establish a model for collaboration with First Nations communities. Not only will 2023 be a year of partnerships, but it will be the year for transforming the future of energy, TODAY!



Gary McNamara
CHAIR,
Essex Power Corporation

John Avdoulos
PRESIDENT & C.E.O.,
Essex Power Corporation

ESSEX POWERLINES CORPORATION

Essex Powerlines
2022 Highlights

As part of Essex Powerlines' customer service road map to modernize the customer experience, a new phone system was deployed in 2022, this solution enhances the customer experience, increases workplace flexibility and assists with regulatory reporting. The organization recognizing the need to change customer communications preferences.

The new phone system provided the opportunity to re-examine, simplify and streamline the call menu customers follow before being directed to a live local Customer Service Representative (CSR). The system includes a built-in Interactive Voice Response component, allowing for recording and automatically sending messages about planned outages to affected customers. In an effort to gain instant feedback on the customers' experience with employees, automated surveys have been added to the end of phone calls.

To meet consumer communication preferences, online chat is an additional avenue for customers to contact Customer Service. Online chat is available 24/7 and is located on every page on the company's website (www.essexpowerlines.ca). During office hours, Artificial Intelligence (AI) technology is embedded in, transferring the customer to a live CSR. After hours, the AI feature is available, asking users pre populated questions in hopes to to provide them with the information the are looking for.

The team's roll-out strategy made for a successful launch with zero interruptions to customer service delivery.

This customer service initiative was recognized by **The Electrical Distributor Association** and Essex Powerlines was awarded the **Customer Service Excellence Award 2022.**

Essex Powerlines Customer Service representatives

The Essex Power team accepting the Customer Service Excellence Award.

Sutton. G. from St.Pius X School, winner of the Go Green: School Edition campaign.

In spring 2022, two new paperless billing campaigns were offered to customers. **Go Green: School Edition** invited youths to show how they reduce their carbon footprint for a chance to win $1,000. The winner of this contest was **Sutton G.** from **St. Pius School Elementary School** in Tecumseh. His video submission displayed his many efforts on how he reduces his carbon footprint. Sutton's school council received the $1,000.

For our fall campaign, **Go Paperless For Pajamas**, Essex Powerlines teamed up with local non-profit **Lola's Pajama Fairy Project.** This group, run by a compassionate young girl named Lola and her family, annually collects pajamas and donates them to local charities during the holiday season. For every sign up for paperless billing, Lola's Pajama Fairy Project received a pair of pajamas. Thanks to our customers who signed up for paperless during this time, 326 pairs of pajamas were donated to our community!

Lola, from Lola's Pajama Fairy Project receiving 326 pairs of pajamas from the Essex Powerlines team.

Essex Powerlines, Power Line Person working onsite in LaSalle, ON.

Innovation

PowerShare

Officially kicked of in March 2022, Essex Powerlines has put the plan into motion, and is building a new real-time local electricity market in Leamington, Ontario.

Benefits

- Utilize customers energy assets
- Reduce GHG emissions
- Support local and provincial grid reliability
- Boost efficacy of existing assets & infrastructure

For more information visit:
www.powershare.energy

Growth within our Service Territory

753	8	3
Residential Connections	Commercial Connections	Generation (Solar)

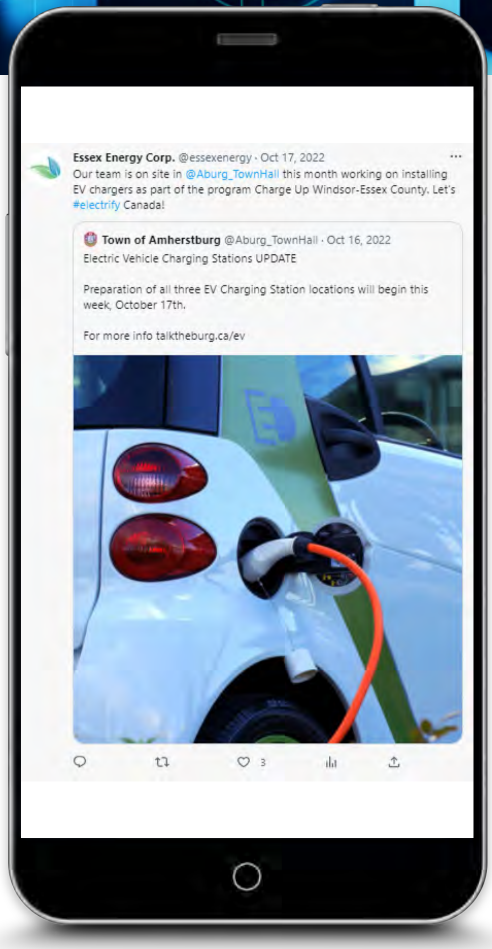
Essex Energy
2022 Highlights

As Canada aims to achieve aggressive climate change goals in coming years, such as a net-zero grid by 2035 and a net-zero society by 2050, Essex Energy Corporation's ("EEC") business development activity remains strong and focused on emerging trends as a means to grow. As such, we've pushed hard to leverage North America's emerging trend of Distributed Energy Resources ("DER") in 2022. What a year, and what a bright future!

"DER" has become a popular acronym in the electricity sector, representing a term that refers to a collection of resources seeking to connect to the grid, and that are capable of providing a wide range of value to consumers, prosumers, and transumers. Solar PV, energy storage, electric vehicles, combined heat and power facilities, wind turbines, waste to energy facilities, and hydrogen fueled generators are all examples of DERs. EEC's solar PV pipeline of contracted design-build commitments, alone, was a major contributor to 2022's resounding success, and will support even further growth in 2023.

Another area of significant growth related to DERs is the launch of EEC's Electric Vehicle ("EV") infrastructure design-build business. It was a significant top line contributor in 2022, and promises to be a sustainable contributor in coming years. This business is complimented by the company's leadership in the Zero Emissions Vehicle Infrastructure Program ("ZEVIP") that is sponsored by Natural Resources Canada ("NRCan") and that EEC is successfully deploying as a means to award **$5,000,000** in funding to many recipients in its shareholder communities and the Essex region as a whole. ZEVIP will be a continued focus in 2023/24 as the program runs its course.

EV Week was celebrated in Tecumseh, ON where media joined to hear all about the success of ZEVIP.



Electricity supply in the Windsor-Essex Region has become a major focus where economic development is concerned. While it doesn't always, necessarily, show on the company's financial statements, the local community can rest assured that EEC is pushing hard, with a loud voice at the provincial level, for the IESO, OEB, Hydro One, and the Ministry of Energy to collaborate innovatively to ensure the region has short, medium, and long term solutions to its rapidly increasing electricity demand.

One example of this is EEC's participation in the Distributor System Operator ("DSO") project, called PowerShare, that Essex Powerlines is deploying in partnership with the IESO and OEB over the next three years. This project has the potential to change the way Local Distribution Companies ("LDC") operate, and enable them to take advantage of DERs in their service territories to relieve – or at least lessen – the capital resources required to keep up with the electrification of society.

As a result of the PowerShare project, EEC is planning to make its first investment in a Battery Energy Storage System ("BESS") – again, leveraging DERs to grow and evolve the company's capital investment strategy, while also offering one of Essex Power's shareholder the opportunity to save operational expense through efficient and innovative use of the BESS.

In order to adapt to the evolving nature (and volume) of the work EEC performs, and in order to de-risk succession planning more broadly, the company will add engineering and financial resources to its highly talented workforce in 2023. Constant and careful investment in human resources will be key to EEC's future in a sector that is rapidly changing!

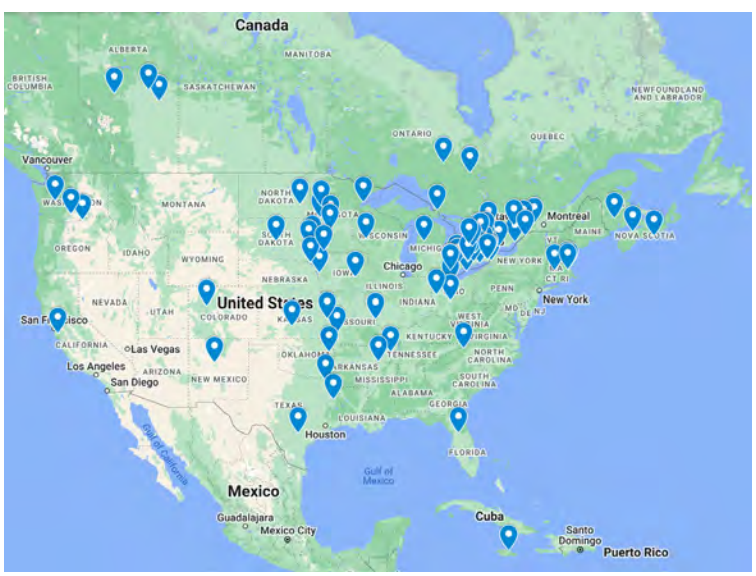
Utilismart
2022 Highlights

The theme of **"Building for the Future"** means many things to a company like Utilismart Corporation. It means investing in new (and existing) products / services and building internal tools and efficiencies required to support them. It means developing the human resources and organizational structure necessary to execute at the next level. And, it means building partnerships with other world class service providers to expand our reach.

Utilismart had a record year for top line sales in 2022. It's a proud achievement, but we're just getting started! While sharply focused on executing sales through internal resources, channel partners, consultants, RFPs, digital marketing, and customer referrals, Utilismart will continue to accelerate its organic growth in both the US and Canadian markets. Continuing the growth trend in the US market, in particular, will be key to the company's success as it represents almost **3000 utilities** that are candidates for the services we offer. Digital transformation is here to stay, and Utilismart has a significant role to play in the sector!

More broadly speaking, governments around the world have been keen to embrace climate change goals, many of which intersect with the energy sector and impact our customers. Utilities are being challenged with a wide range of obligations that include:

- Distributed Energy Resources ("DER") integration – or at least visibility to start
- Electrification of transportation and other sectors – Like real estate!
- New consumer, prosumer, transumer trends (ex. Green Button)
- Regulatory burden across all departments



Snapshot of Utilismart Customers

Utilismart exhibiting at DistribuTech 2022.

Deriving maximum value from their data has never been more important for utilities that wish to succeed in the future. Hence, it is essential for utilities to transform digitally. Enter Utilismart… Our purpose is to help our customers mitigate risk and Build for the Future. Our ever-evolving cloud-based software and data solutions accomplish this!

Internally, having mitigated significant risk related to the company's product-related Intellectual Property through the launch of a new product department in 2022, Utilismart will continue to realize deeper efficiencies in product development cycles in 2023. Also, risk related to cyber security and our IT infrastructure will always remain a top priority as the company achieved ISO 27001 recertification in Q1.

Finally, back at the corporate offices, the workplace impacts of the global pandemic began to decline by the end of 2022. This has enabled Utilismart to settle into more regimented scheduling of employees' time. In Q4 of 2022, a final version of the company's remote work policy was issued forming the cornerstone of a new "hybrid" arrangement for office attendance intended to produce win-win-win (employee-employer-customer) results going forward. Navigating through over two years of pandemic disruption has been difficult to say the least. Our employees at all levels have overcome the challenges with great success!

Proceeds from the Utilismart Golf Classic donated to CMHA Thames Valley.

Annual Utilismart Golf Classic 2022

WattsWorth
2022 Highlights

In 2022, WattsWorth Analysis Inc. ("WW") invested considerable time and effort in a submission to the Ontario Education Collaborative Marketplace ("OECM") in response to their Request for Proposals for energy management services. OECM is a not-for-profit procurement firm that services the public sector in Ontario – primarily the School Boards. The scope of WW's submission covered regular electricity consulting services for **56 School Boards** representing **4,999 schools** across the province. Subsequently, WW was named one of three winners of the RFP, leading to an intense marketing campaign, targeting all Ontario school boards, with the goal of attracting a completely new segment to WW's customer base. A big win with great potential!

After launching a software application call "WattsWorth Energy Portal" or "WWEP" in 2021 as a beta version to a small sample of existing municipal customers, WW spent much of 2022 converting the beta product to a fully functioning cloud-based application available to the broader market. Initial feedback regarding WWEP has been positive as the company launched a demo campaign targeting new prospects. In Q4 of 2022, the offering attracted its first customer! 2023 will focus on marketing and selling the WWEP (leveraging our reference customer) as well as adding functionality that was highlighted as a need by users – namely 507/18 regulatory reporting support. Reg 507/18 mandates that municipal entities must report annually on Greenhouse Gas ("GHG") emissions on a 'per square foot' basis for all corporate facilities. 507/18 reporting is challenged by resource constraints for many municipalities, and as such this will become a marketing theme for the product in 2023.

WattsWorth Energy Portal

WattsWorth's **40+ customers** that include municipalities, large electricity consumers, and generators have expressed great gratitude to the company for consistently providing top grade services, without interruption, throughout the entire global pandemic. **Congrats to WattsWorth employees!**

Global Reporting **Initiative**

The Global Reporting Initiative (GRI) is an internationally recognized standardized framework for disclosing an organization's environmental, social and economic performance. The GRI is a commonly used tool that many organizations in Ontario, Canada, as well as around the world use. For Essex Power's report, please visit **www.essexpower.ca**

About GRI

EPC's report focuses on its operations, which leads to the process of defining the report content and topic boundaries. The organization used past reports and meetings between employees to define the report content. Material topics were decided on by a team who consulted previous reports, current company documents and operations, and future trends.

Essex Power Corporation has reported in accordance with the Core option, and therefore reported on the required disclosures from GRI 102.

Report Scope and Boundaries

Our regulated electricity distribution company, Essex Powerlines, is accountable for providing a safe, reliable and cost-effective supply of electricity to the municipalities of all our stakeholders and communities. The scope of this report and GRI submission includes all of the Essex Power Group of Companies.

To measure our success and progress in sustainability, we have defined key areas that we see are of great importance to achieving success. Essex Power has made sustainability a core foundation for all decision-making and has initiated best practices for managing operational and environmental risk. The GRI report analyzes and measures Essex Power's performance within the three pillars of sustainability.

Environmental stewardship is evaluated by our success in energy conservation, renewable energy investment, and environmental risk mitigation of our operations.

Social responsibility is evaluated by how we ensure the safety and wellness of people including our employees, our contractors, and our communities. We are committed to providing a safe and respectful workplace where employees are highly valued, treated fairly, provided with challenging and meaningful work, and benefit from opportunities for knowledge growth and career development.

How it works

How we measure our success and progress

2022 Social **Performance**

Community engagement and philanthropic support remained at the heart of Essex Power's corporate philosophy in 2022; corporations have a responsibility to invest in economic, social and environmental well being of their neighbours. Essex Power continued to support our communities through various charitable donations and employee involvement.

2022 Wellness Initiatives

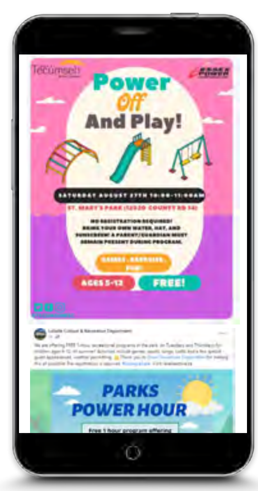
Rock your Socks
Chasing Hazel Foundation Donation (March)

Random Act of Kindness
Donation to Humane Society (February)

$500

Bursary Program awarded to a Grade 12 graduating student. The recipient is pursuing post secondary education in the areas of study that build and support our industry for example Powerline Technician and the many STEM avenues of study. Eight students were recipients.

$40,000



EPC Youth in Community Fund, 9th consecutive year: $10,000 to Amherstburg, Leamington, Lasalle, and Tecumseh to be used towards youth-oriented programming and initiatives.

$5000

Provided $5,000 in in-kind services to each of our municipal Shareholders.

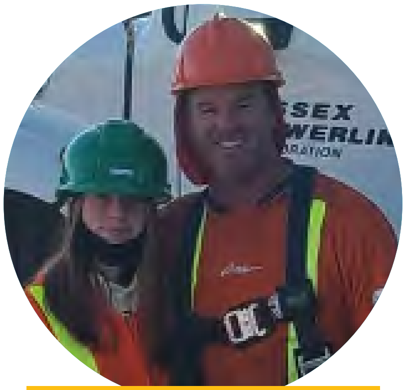
Sponsored local families this holiday season through **Windsor-Essex Children's Aid Society, Adopt A Family Program**

Sponsored **local organizations** and **charities** through community events

$4000

Donated to local food banks.

- Amherstburg Food and Fellowship Mission
- Tecumseh Goodfellows
- Leamington Salvation Army
- St. Andrew's LaSalle Food Bank



Bring your Child to Work Day

Participated in the Co-operative education programs and **Windsor-Essex Career Apprenticeship Program** (WECAP)

2022
Fast Facts

85% Public Safety Awareness Index Score

86% Overall Satisfaction

77% Quality of Service

84% Quality of Customer Service

20,537 EPL Call Centre Calls

34,286 Total Customers

6,289 Poles

117 New Service Installed

1,139 Overhead Transformers

1,942 Underground Transformers

Total Electricity Consumed

272,588,249kWh Residential

251,490,393kWh Commercial & Industrial

25 Fleet Vehicles

180 km Primary Overhead Lines

427 km Secondary Overhead Lines

279km Primary Underground Cable

743km Secondary Underground Cable

Corporate
Structure

Committed to strong corporate governance and accountability, the Board of Directors brings a depth of experience to governing Essex Power Corporation in the best interests of customers and the community.

SHAREHOLDERS

Municipality of Leamington live | play | work

Tecumseh

Amherstburg Ontario, Canada Est. 1796

LaSalle

Essex Power Corporation **(Holdco)**
John Avdoulos
President & CEO

BOARD OF DIRECTORS

Gary McNamara, Chair Marc Bondy, Vice Chair
Tom Burton, Aldo DiCarlo, Hilda MacDonald, Frank Ricci, Bill Wark , John Wladarski

Essex Powerlines Corporation

BOARD OF DIRECTORS

Aldo DiCarlo, Chair
Mark Galvin, Hilda MacDonald,
Bill Wark, John Wladarski , Victoria Zuber

EssexEnergy Corporation

BOARD OF DIRECTORS

Marie Campagna, Chair
Marc Bondy. Tom Burton, Gary McNamara,
Frank Ricci, Raymond Tracey

utilismart Corporation

WattsWorth the energy analysis people

Essex Power Corporation is a dynamic energy company that provides safe, reliable and economical energy supply and services to our customers. Our commitment to innovation, performance management and leading by example has built the foundation for Essex Power and our affiliates to establish a diverse set of energy products and services that are valued by our customers.

Essex Energy Corporation is a dynamic energy company that focuses on implementing a wide range of energy related initiatives, including but not limited to, solar PV projects, site feasibility assessments, and full turnkey solar PV solutions. With almost 20 years of experience in the energy market, EEC has grown its success and has exceeded boundaries in Ontario by developing its in-house expertise and Distributed Energy Resources portfolio of assets and services, as well as its engineering and consulting services. As a leading energy technology company, EEC has been called on to assist both nascent and established solar PV developers in the completion, connection, monitoring, and maintenance of their solar PV projects, and to date, manages over 100MW of distributed generation equipment. EEC provides streetlight maintenance services to our shareholder communities and is registered with the IESO as a Metering Service Provider currently maintaining a total of 23 wholesale metering installations.

Essex Powerlines Corporation, a regulated company, provides safe, reliable and economical electrical distribution and service to over 34,000 residents and businesses in Amherstburg, LaSalle, Leamington, and Tecumseh. The foundation to empower our corporate vision is based on a dynamic and progressive workforce that will be industry leaders in providing "best in class" business solutions in the delivery of service to our customers.

Since 2002, **Utilismart** has been the industry leader in providing settlement services to utilities throughout Ontario. Our services are built on industry expertise and an in-depth understanding of both the settlement processes in the marketplace and the needs of the customer. Our hosted solutions offer customers an economical, efficient settlement service that has built-in reporting and analysis tools. Our knowledge in this area allows for seamless integration into CIS, Financial, and other customer systems requiring settlement data.

As a Canadian company based in Ontario, **WattsWorth** offers a variety of energy management services to participants in the Ontario market. Our clients include large industrial/commercial companies, electric utilities, electricity generators and municipalities. WattsWorth has over 1-billon kWh consumed annually. In addition to technical expertise and a highly specialized and robust infrastructure, WattsWorth makes a commitment to listen to our clients' requirements and tailor solutions that respect their objectives. WattsWorth has a business manner that reflects high standards of professionalism, attention to detail, and a logical approach to problem solving.

ESSEX POWER
CORPORATION

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info@essexpower.ca
essexpower.ca

Municipality of Leamington
Town of Tecumseh
Amherstburg
LaSalle

Attachment 1-H

Customer Engagement Survey

INNOVATIVE RESEARCH GROUP

Essex Powerlines

2023 Rate Application Survey

Residential and Small Business Results

ESSEX POWERLINES CORPORATION

FINAL REPORT | December 2023

Setting the Context

Essex Powerlines 2023 Customer Engagement Survey

Innovative Research Group Inc. (INNOVATIVE) was engaged by Essex Powerlines to assist in meeting its customer engagement commitments under the Renewed Regulatory Framework for Electricity Distributors and Chapter 5 Filing Requirements. The information contained within this report is the result of a series of residential and small business online surveys.

Setting the Context

Essex Powerlines is in the process of finalizing its 2024-2029 Investment Plan. This report covers the results of a series of customer surveys that were used to gather customer needs and preferences, both generally and in relation to specific areas of interest to the utility. This survey was deployed to all residential and small business customers with an email address.

Interpreting the Results

For residential customers, responses were weighted by region and electricity usage to ensure the responses were representative of the broader customer base. Due to the relatively small sample size, small business results were not weighted and are expressed in frequencies rather than percentages. Small business results should be interpreted with caution.

INNOVATIVE RESEARCH GROUP

Summary of Findings

1

66% of residential customers are satisfied with the services they receive from Essex Powerlines.
In terms of unmet needs, 33% of residential customers feel that Essex Powerlines should improve the current levels of reliability.

2

When asked to rank priorities, most customers select reliable electrical service or reasonable electricity distribution prices.
In terms of top priority, more residential customers select reliability over price. Most customers cannot point any other priorities that Essex Powerlines should focus on other than what was provided in the survey.

3

89% of residential customers say that they have experienced at least one outage in the past year.
Residential customers would like to see Essex Powerlines prioritize restoration times during extreme weather, reducing the number of outages caused by extreme weather, and improvements to power quality.

4

With regards to investments in technology, residential customers prioritize finding efficiencies and reduced customer costs and improved reliability.
Technology that enables customer access to new services or make it easier to interact with the utility are seen as less important.

5

29% of residential customers say that they are at least somewhat likely to invest in an electric vehicle in the next 5 years.
In the next 10 years, 57% of residential customers expect their electricity usage to stay the same as today.

Methodology & Sample Design

INNOVATIVE
RESEARCH GROUP

Methodology

Innovative Research Group (**INNOVATIVE**) was commissioned by **Essex Powerlines** to conduct a customer engagement online survey among their residential and general service under 50kWh rate classes in preparation for their rate application filing with the Ontario Energy Board. All customers with an email address available on file were invited to participate in the online survey.

Sample Size:

Residential customers: 1,874 completed surveys weighted to 1,850 by region and consumption quartile.
Small business customers: 21 completed surveys. Data for this rate class is not weighted due to its small sample size. Additionally, throughout the report, results for GS<50 customers are discussed in frequencies rather than percentages.

Field Dates:

November 27th to December 14th, 2023. All customers with an email on file were invited to complete the survey via a unique URL delivered to their mailbox.

Weighting:

Weighting for residential customers is based on the distribution of Essex's full customer list on two key variables: region and average monthly consumption quartile. Statistical weights are applied to the sample to ensure it is representative of Essex Powerline's actual customer base.

Margin of Error:

The margin of error for a sample of n=1,850 is approximately ±2.3%, at the 95% confidence level. Given Essex Powerlines does not have 100% email coverage of their customer population, the level of sampling error reported may be impacted by coverage error.

Note: *Graphs may not always total 100% due to rounding values rather than any error in data.*
Sums are added before rounding numbers.

Sample Design

In total, **12,967** Essex Powerlines residential and small business customers were invited, via unique URL, to participate in this study. In total, **1,895** customers completed the entire survey, resulting in a **15.1%** residential response rate and **3.8%** response rate among small business customers.

The residential sample has been weighted proportionately by consumption quartiles and region in order to be representative of the broader Essex Powerlines service territory. Consumption quartiles are calculated by dividing all Essex Powerlines residential and small business customers into 4 tranches based on their most current consumption data.

The table below summarizes the unweighted and weighted sample breakdown by quartile and region for **residential** customers.

Region	Low		Medium-Low		Medium-High		High		Total	
	Weighted	Unweighted	Weighted	Unweighted	Weighted	Unweighted	Weighted	Unweighted	Weighted	Unweighted
LaSalle	167	170	181	195	197	241	233	234	777	840
Amherstburg	73	66	66	105	65	53	49	68	253	292
Leamington	114	105	106	85	98	79	81	52	399	321
Tecumseh	110	109	109	118	103	98	99	96	421	421
Total	**463**	**450**	**463**	**503**	**463**	**471**	**462**	**450**	**1,850**	**1,874**

Explaining Customer Segmentation

Regional and Customer Segmentation

Segmentation has been used throughout this report to look beyond the topline numbers to analyze the results for key segments:

1. **Region:** Using customer data provided by Essex Powerlines, we split customers into 4 sub-regions for analysis; LaSalle, Amherstburg, Leamington, and Tecumseh.

2. **Vulnerable Consumers**: For residential customers, using a combination of household size and combined household income, the residential portion of this report identifies customers who would be eligible for financial assistance programs. The methodology used to calculate this segmentation is based on the OEB's *Low-income Energy Assistance Program* (LEAP) criteria.

Understanding Segmentation

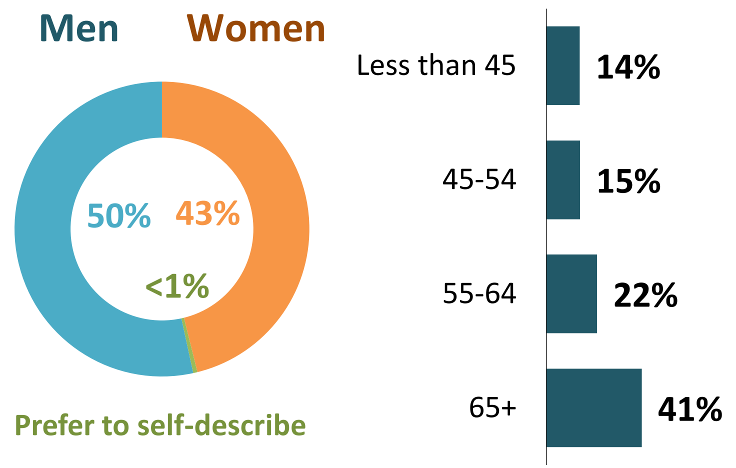
Segmentation is an effective way of looking past the topline numbers and dig deeper into the needs and preferences of the customer segments outlined above. For instance, while it is valuable to know that overall, 66% of residential customers are satisfied with Essex Powerlines, it is also important to understand whether satisfaction differs based on region or based on circumstances that may be outside of the utility's influence or control, including financial circumstances. Segmentation allows readers of this report to quickly look past the topline numbers and understand how various segments of customers feel about various issues.

Demographics

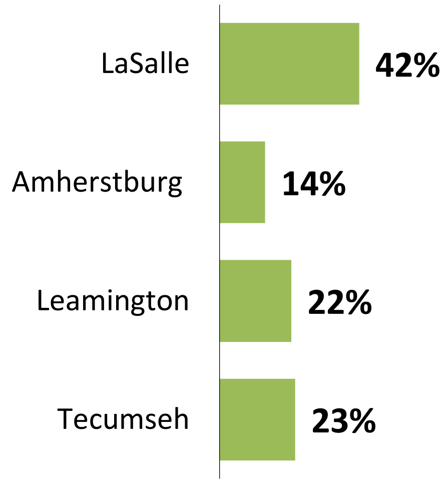
Demographics: Respondent Profile

Residential

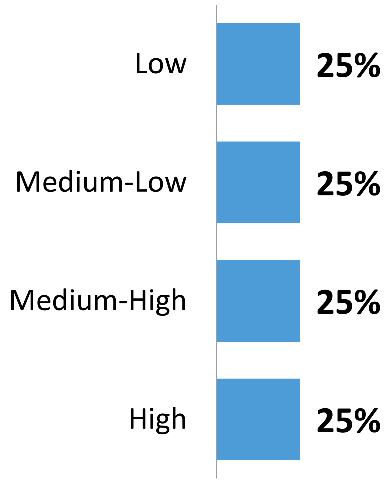
Gender & Age



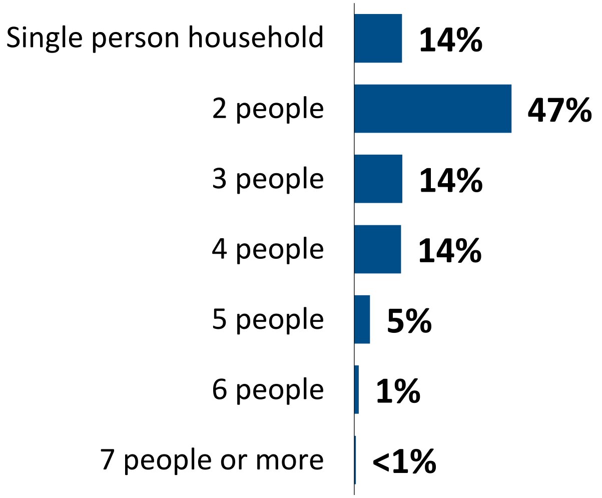
Region



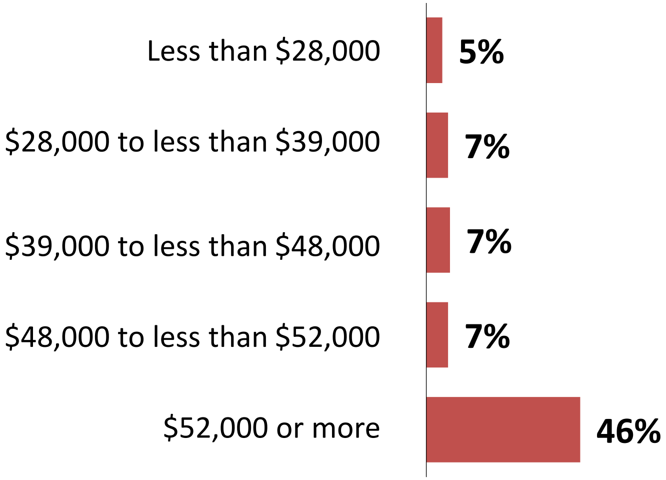
Consumption Quartile



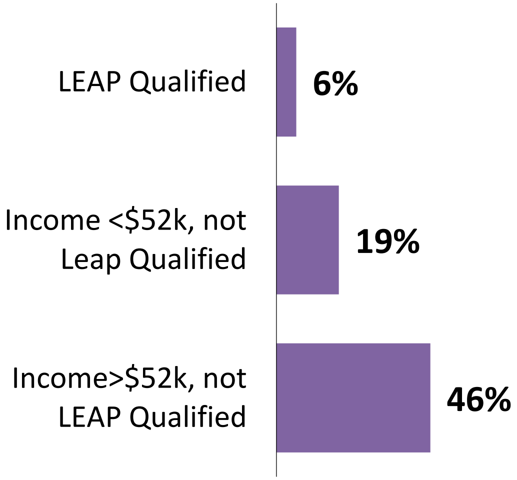
Household Size



After-Tax Household Income



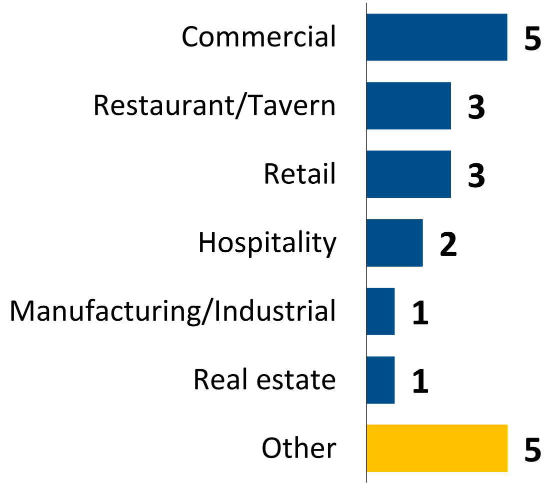
LEAP Qualification*



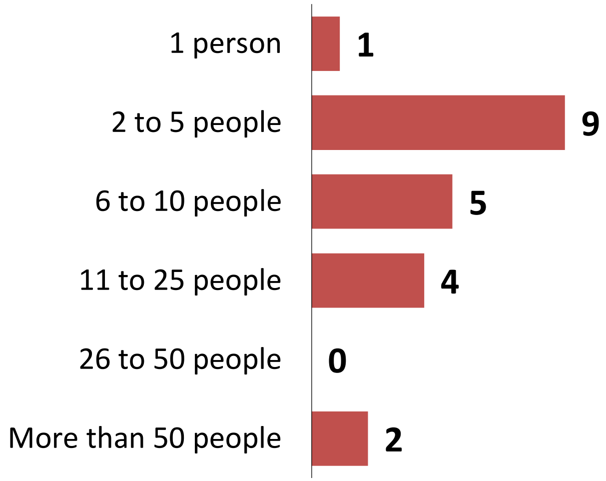
Note: 'Don't know' and 'Prefer not to say' not shown. *Calculated based on household size and household income

Firmographics: Respondent Profile

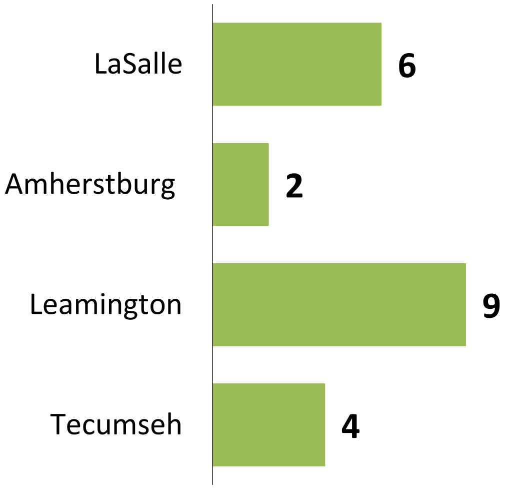
Sector



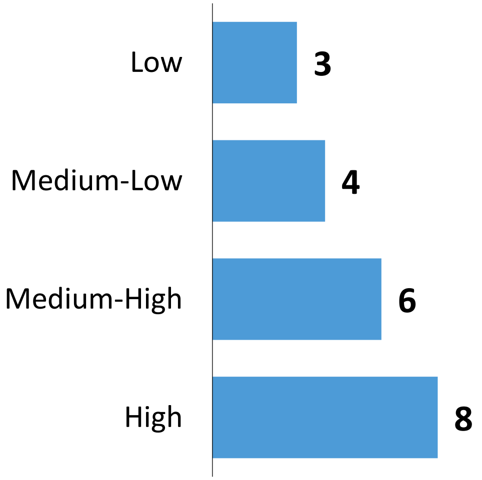
Number of Employees



Region



Consumption Quartile



Note: 'Don't know' and 'Prefer not to say' not shown; results shown in frequencies rather than percentages due to small sample size.

Satisfaction

Preamble:

Ontario’s electricity system has three key components: **generation**, **transmission** and **distribution**.

- **Generating stations** convert various forms of energy into electric power;
- **Transmission lines** connect the power produced at generating stations to where it is needed across the province; and
- **Distribution lines** carry electricity to the homes and businesses in our communities.

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Familiarity with Local Distribution System

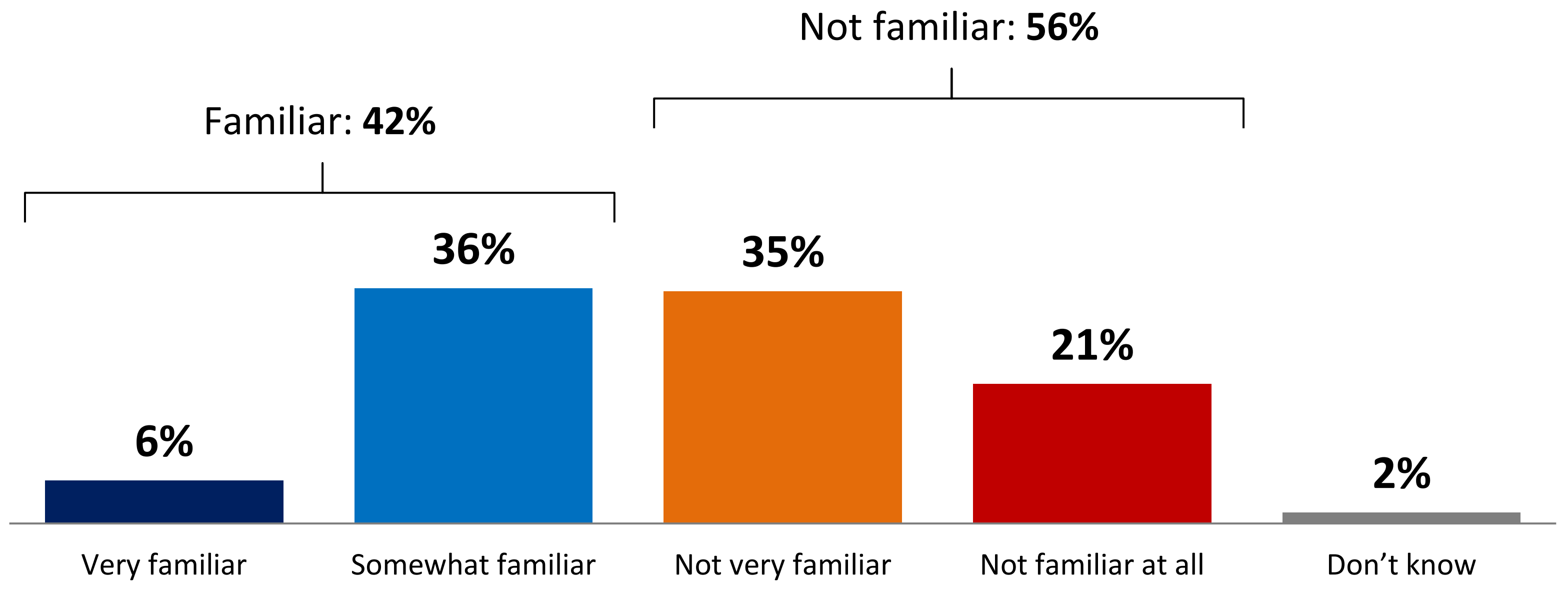
2-in-5 (42%) are very or somewhat familiar with the local electricity distribution system

Q

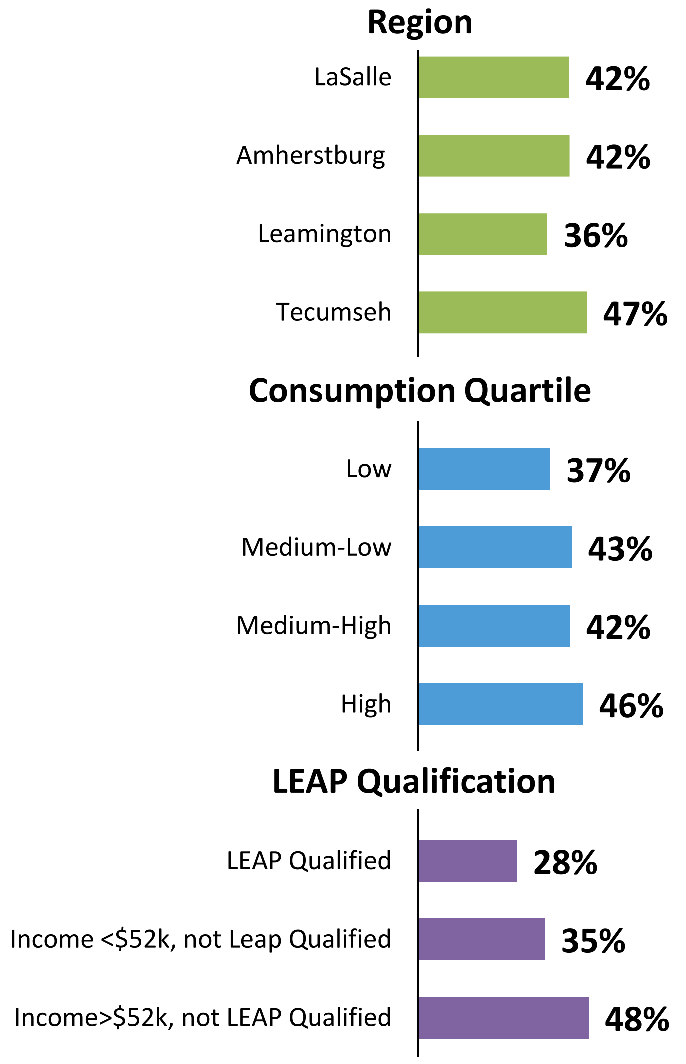
Today we're going to talk about your **local distribution** system which, in your community, is maintained and operated by **Essex** Powerlines.

How familiar are you with the local electricity distribution system?
[asked of all respondents; n=1,850]

Small Business (GS<50)
16/21 say they are very or somewhat familiar.



Segmentation
Respondents who say "Familiar"



Satisfaction with Service

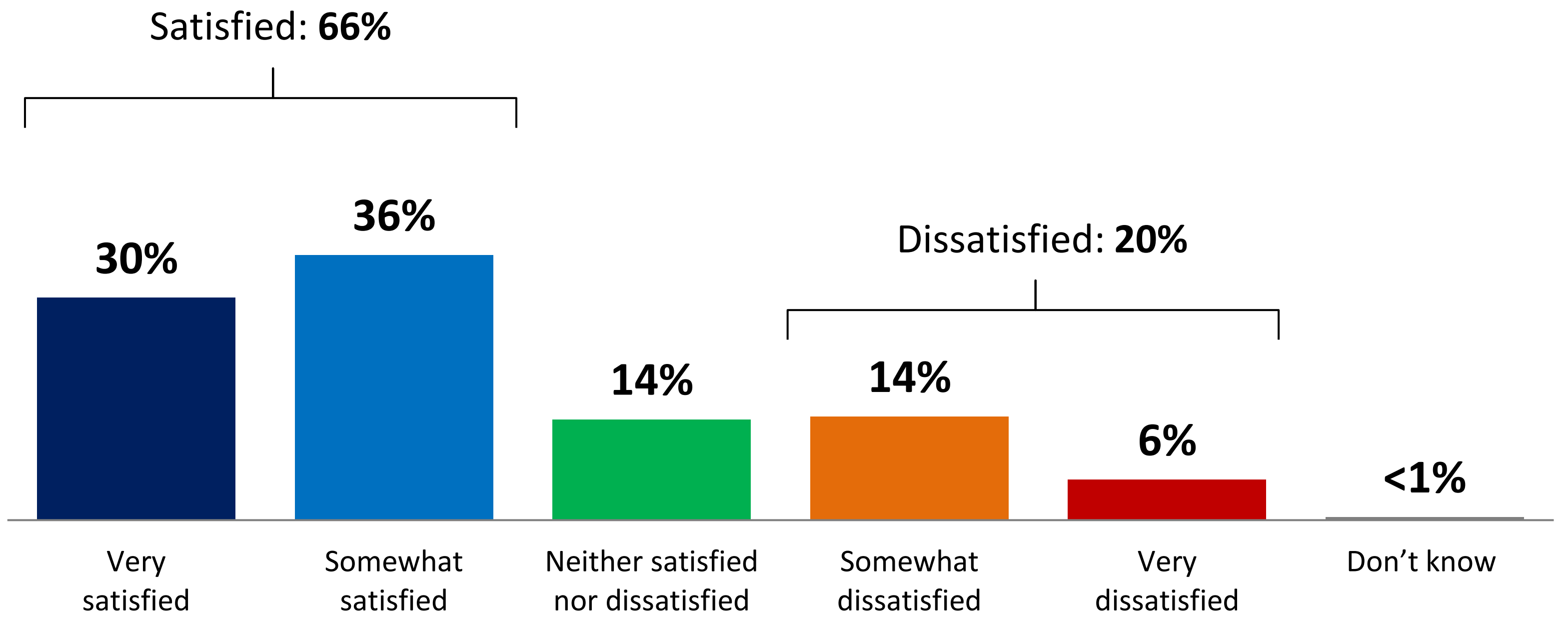
2-in-3 (66%) are satisfied with the service they receive; higher among low-consumption customers

Q

Overall, how satisfied or dissatisfied are you with the service [you receive/your organization receives] from **Essex Powerlines**?

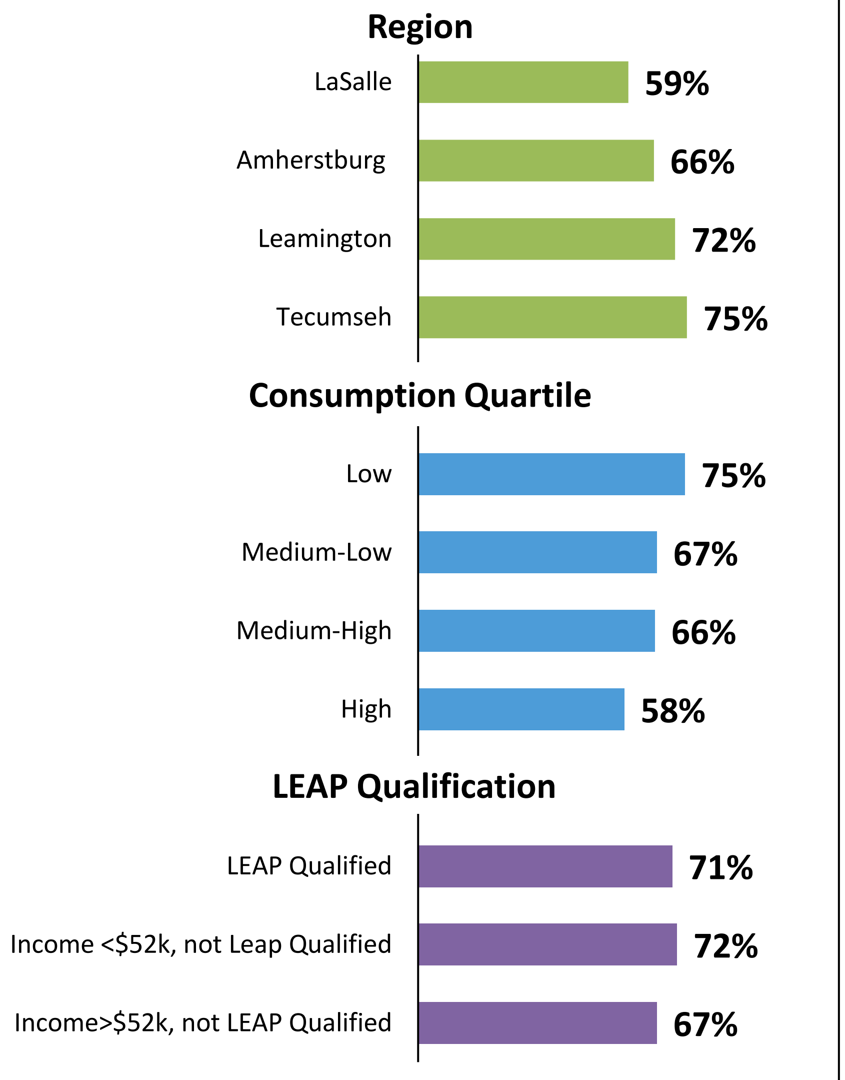
[asked of all respondents; n=1,850]

Small Business (GS<50)
14/21 say they are satisfied and 4/21 say they are dissatisfied. The remaining are neutral.



Segmentation

Respondents who say "Satisfied"



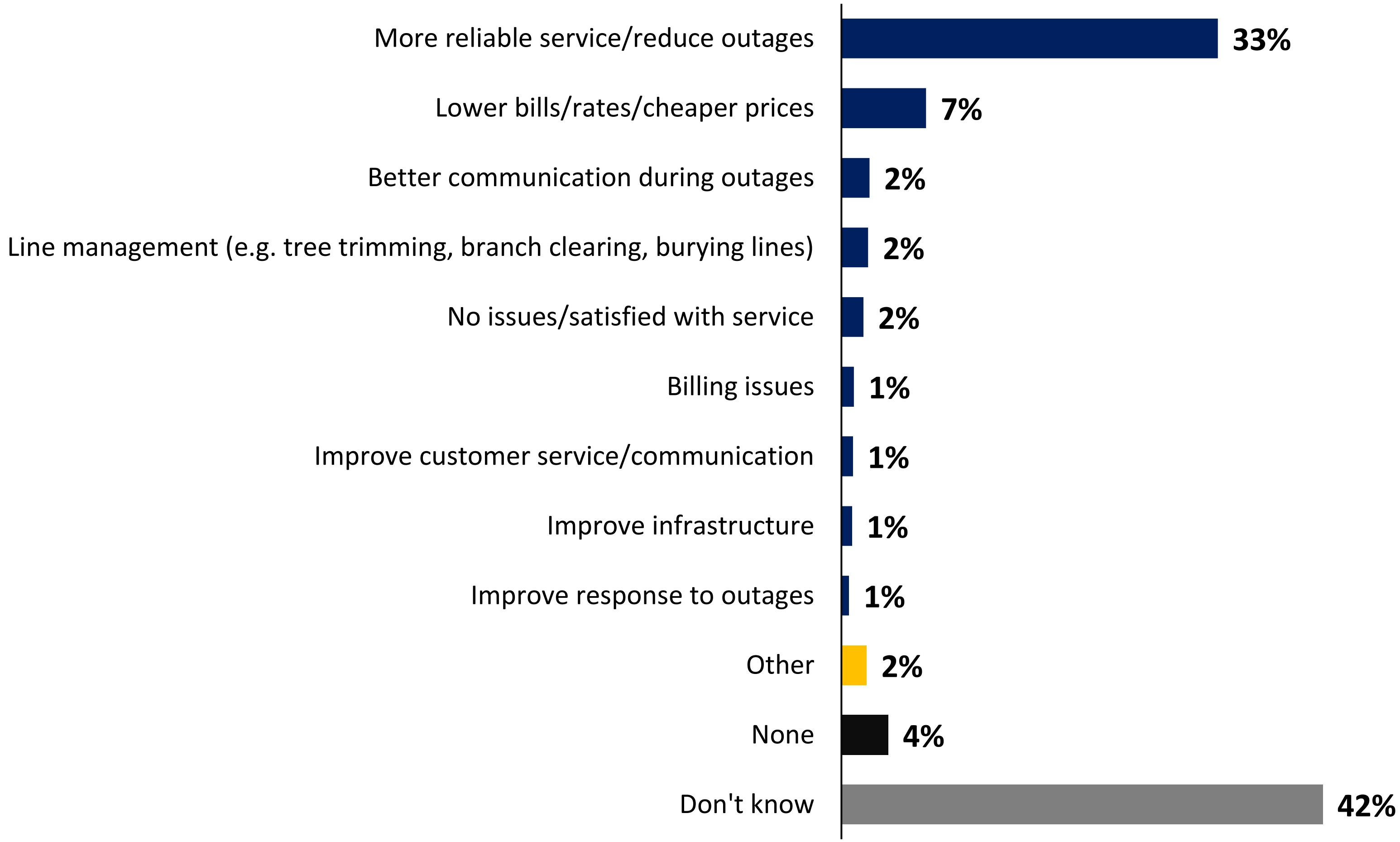
Service Improvement

A plurality don't know (42%); clear top response is to provide more reliable service/reduce outages (33%)

Q

Is there anything in particular **Essex Powerlines** can do to improve its service to you?
[asked of all respondents; n=1,850]

Residential Customers



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Service Improvement

Q

Is there anything in particular **Essex Powerlines** can do to improve its service to your organization?
[asked of all respondents; n=21]

Small Business (GS<50) Customers

"Prevent constant brownouts."	*"With an emerging market of electric vehicles, the ability to provide distributions to businesses will have to keep pace. It would be helpful if Essex Powerlines passed on any communication regarding the things owners should be aware of when they eventually install the charging stations."*
"Give back our security deposit we've paid every bill on time every month for over 2 years."	*"The service goes out too often and it's hell trying to contact the offices and speak to an actual human being to get an ETA of when the electricity will come back. As a small business, I have been disappointed too many times about the power outages and the time it takes to get it back up and running which disturbs my business greatly as we depend on the electricity for our equipment to run. For the rates that we pay (which might I add is astronomical) we all should get much better service or reduce what we pay."*
"Lower price a little bit :)."	*"Have Kelcom or whoever you have a service number answer the phone, when the office is closed. Not all issues occur when the office is open. I know from a past experience."*
"Lower prices my bills are so expensive every month."	
"Quit having power outages and flickers."	
"Price."	
"Invoicing processes."	

Bill Remittance

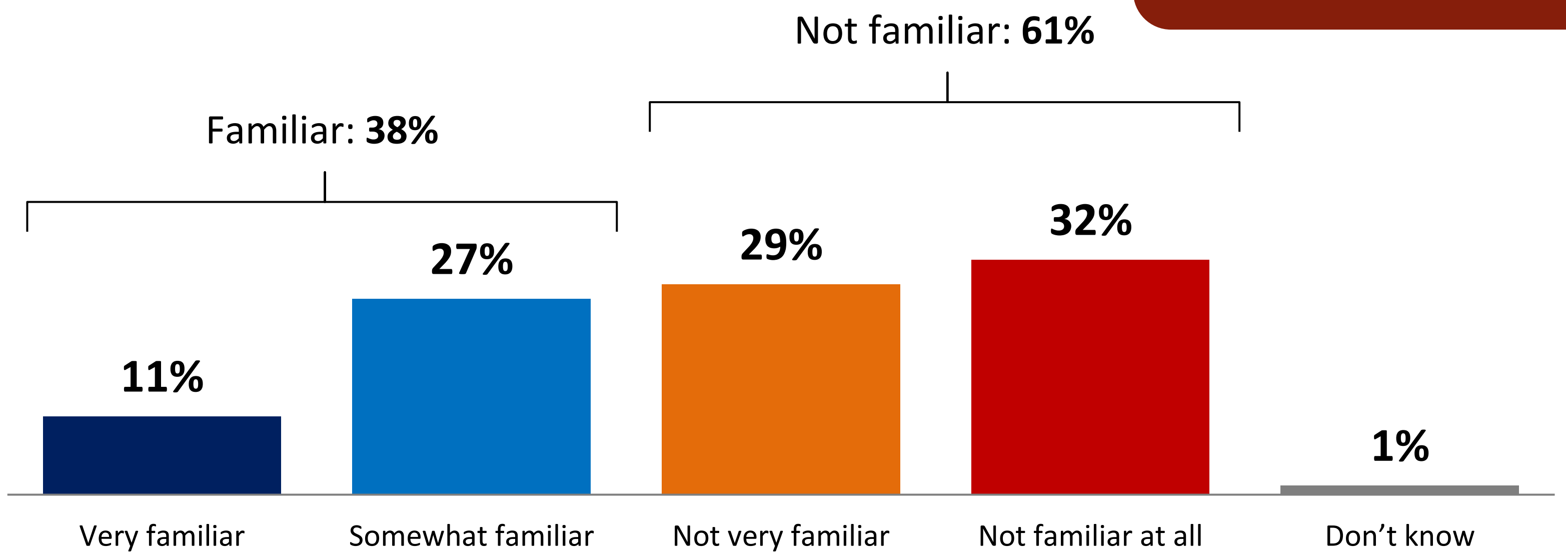
Just over one third are familiar with the share of their bill that goes to Essex while 61% are not familiar

Q

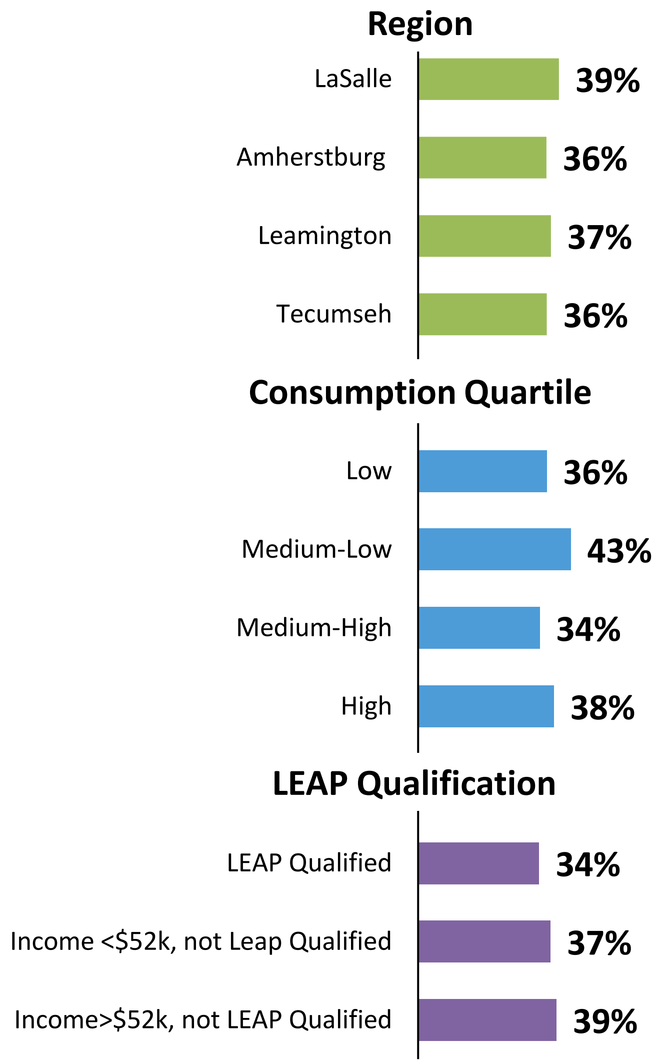
The average [residential/small business] customer pays a fixed monthly service charge of [$29.68/$39.99] which goes to Essex Powerlines. This accounts for approximately 17.8% of a typical [residential/small business] customer's total bill. The rest of the bill goes to power generation companies, transmission companies, the provincial government and regulatory agencies.

Before this survey, how familiar were you with the amount of [your/your organization's] electricity bill that went to **Essex Powerlines**?
[asked of all respondents; n=1,850]

Small Business (GS<50)
11/21 say they are very or somewhat familiar.



Segmentation
Respondents who say "Familiar"



Priorities

Preamble:

Essex Powerlines regularly holds discussions with its customers to better understand how it should set spending priorities with the money customers pay for service.

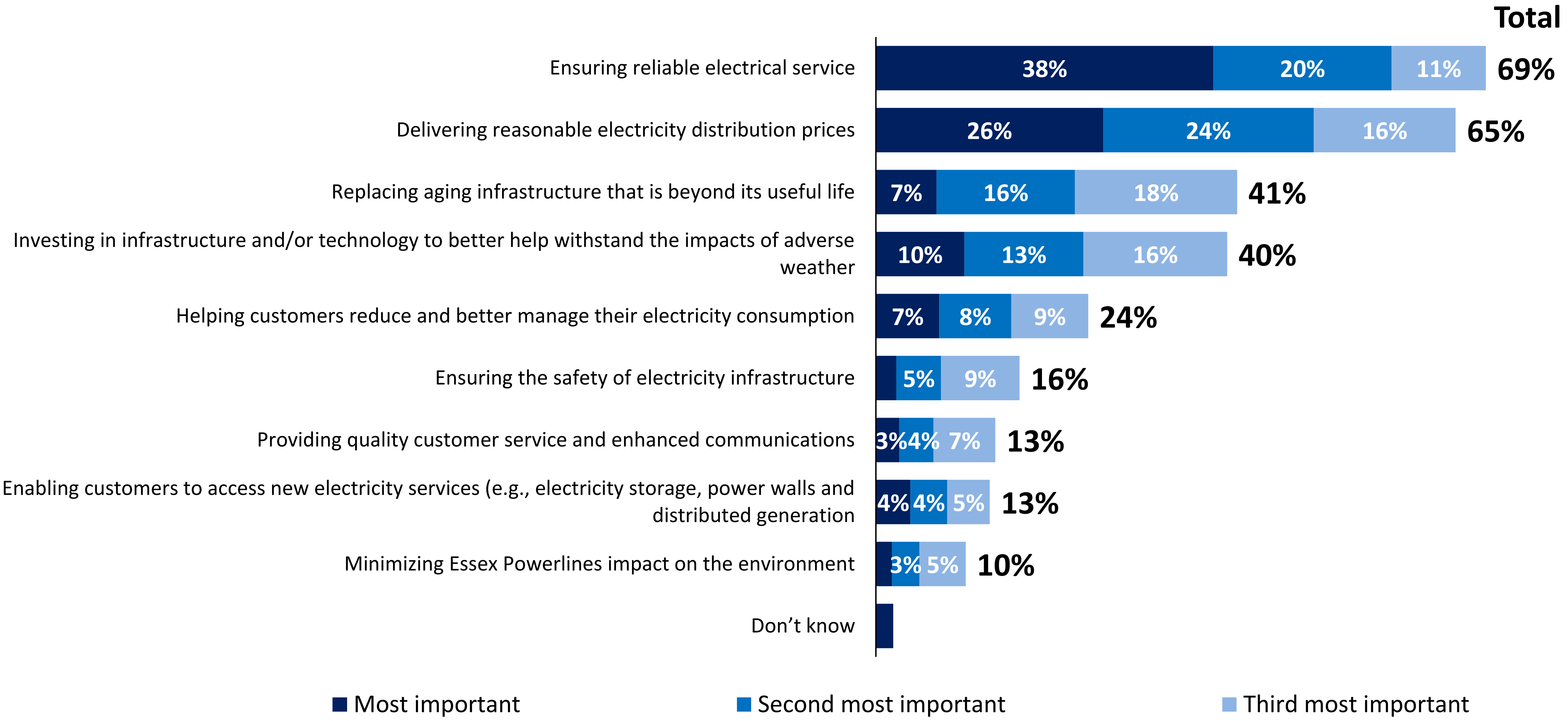
In recent conversations with customers, a number of company goals were identified as key priorities for **Essex Powerlines**.

Ranking Priorities

Reliable service and delivering reasonable prices are top priorities

Small Business (GS<50)
7/21 rank 'delivering reasonable electricity distribution prices' as their top priority. Another 7/21 say 'ensuring reliable electrical service' is the most important.

Q Among the following **Essex Powerlines** priorities, please indicate which one is most important to [you/your organization]. What is the next most important priority you think Essex Powerlines should focus on? And what do you consider the third most important priority?
[asked of all respondents; n=1,850]



Ranking Priorities by Segments

Across all segments, ensuring reliable service and delivering reasonable prices are the top two priorities

Q Among the following **Essex Powerlines** priorities, please indicate which one is most important to you. What is the next most important priority you think Essex Powerlines should focus on? And what do you consider the third most important priority?

[asked of all respondents; n=1,850]

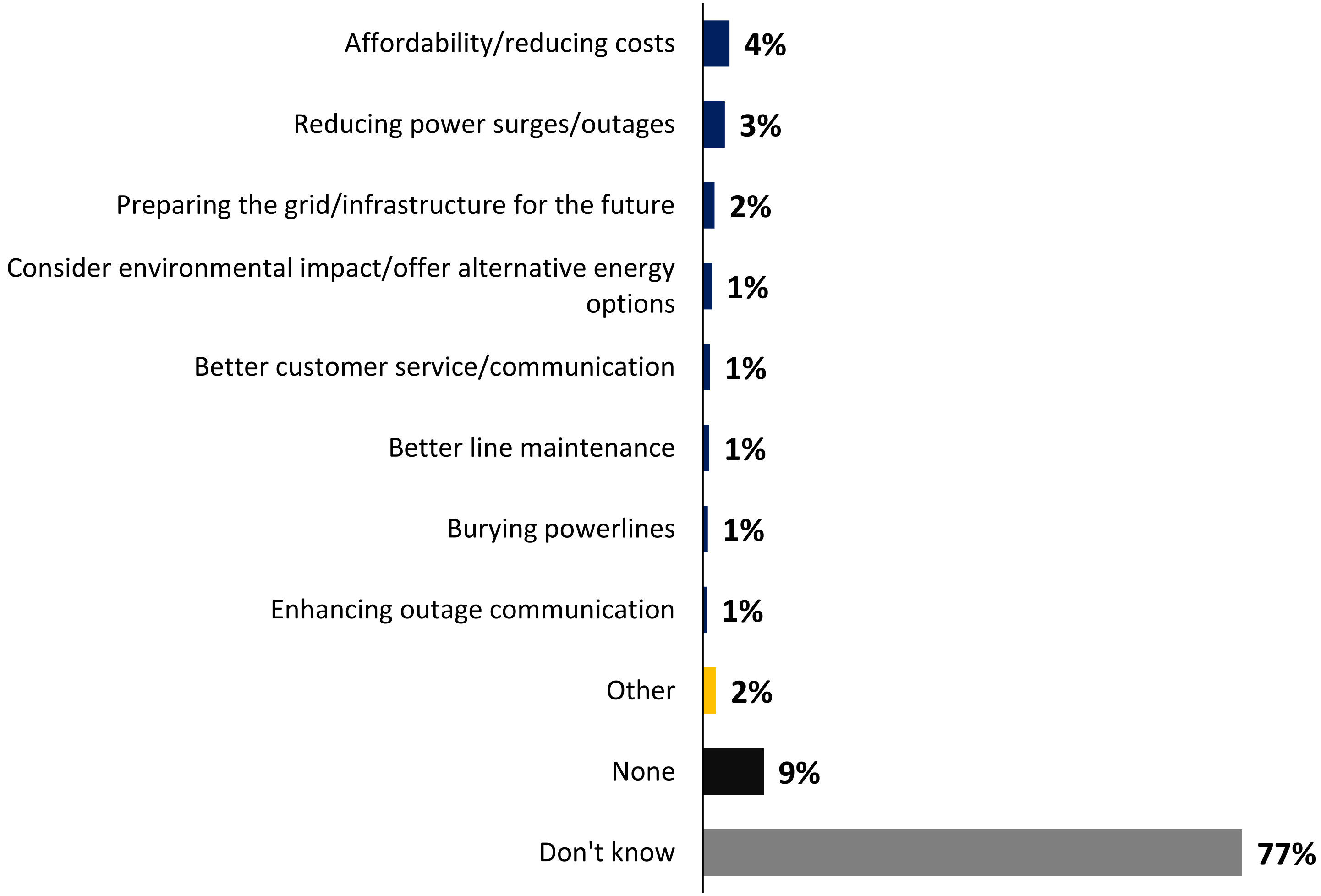
% Select as top three priority	Region				Consumption Quartiles				LEAP Qualification		
	LaSalle	Amherst-burg	Leaming-ton	Tecumseh	Low	Medium-Low	Medium-High	High	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified
Ensuring reliable electrical service	75%	68%	62%	63%	65%	69%	69%	72%	57%	64%	70%
Delivering reasonable electricity distribution prices	64%	69%	65%	66%	65%	65%	63%	69%	62%	70%	61%
Replacing aging infrastructure that is beyond its useful life	42%	44%	35%	41%	40%	40%	42%	41%	35%	38%	44%
Investing in infrastructure and/or technology to better help withstand the impacts of adverse weather	44%	35%	39%	36%	36%	40%	41%	41%	27%	31%	43%
Helping customers reduce and better manage their electricity consumption	20%	20%	27%	30%	26%	25%	20%	24%	28%	30%	23%
Ensuring the safety of electricity infrastructure	16%	14%	15%	19%	20%	14%	17%	14%	19%	19%	15%
Providing quality customer service and enhanced communications	12%	19%	16%	11%	15%	14%	13%	11%	19%	14%	12%
Enabling customers to access new electricity services	10%	17%	13%	16%	11%	12%	13%	14%	14%	12%	15%
Minimizing Essex Powerlines impact on the environment	10%	6%	12%	11%	10%	11%	11%	9%	6%	12%	12%

Other Priorities to Focus On

Over 4-in-5 (85%) residential customers do not suggest any other important priorities Essex should focus on

Q Are there any other important priorities that **Essex Powerlines** should be focusing on that weren't included in the previous list?
[asked of all respondents; n=1,850]

Residential Customers



Small Business (GS<50) Customers

"Separate residential and commercial grid to control and manage during interruptions."

"As I have other proprietary under other company and paying way cheaper then Essex Powerlines so management has to look in it."

"Continuing to find ways for cheaper power/energy and actually enforcing them."

"Preventing outages or flashes."

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Reliability & Technology

Preamble:

Despite best efforts, no electrical distribution system can deliver perfectly reliable electricity. As a general rule, the more reliable the system, the more expensive the system is to build and maintain.

With that said, the average **Essex Powerlines** customer experiences **one** unplanned power outage per year.

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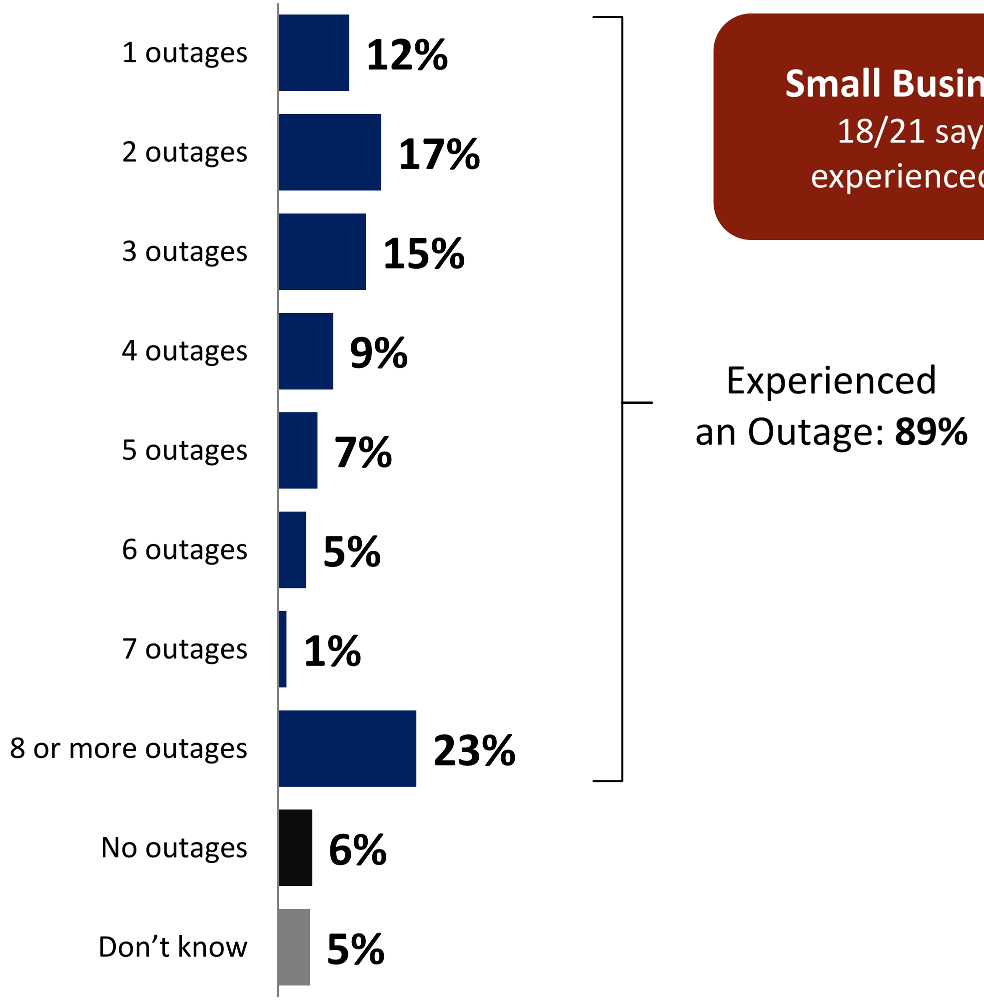
Outage Experiences

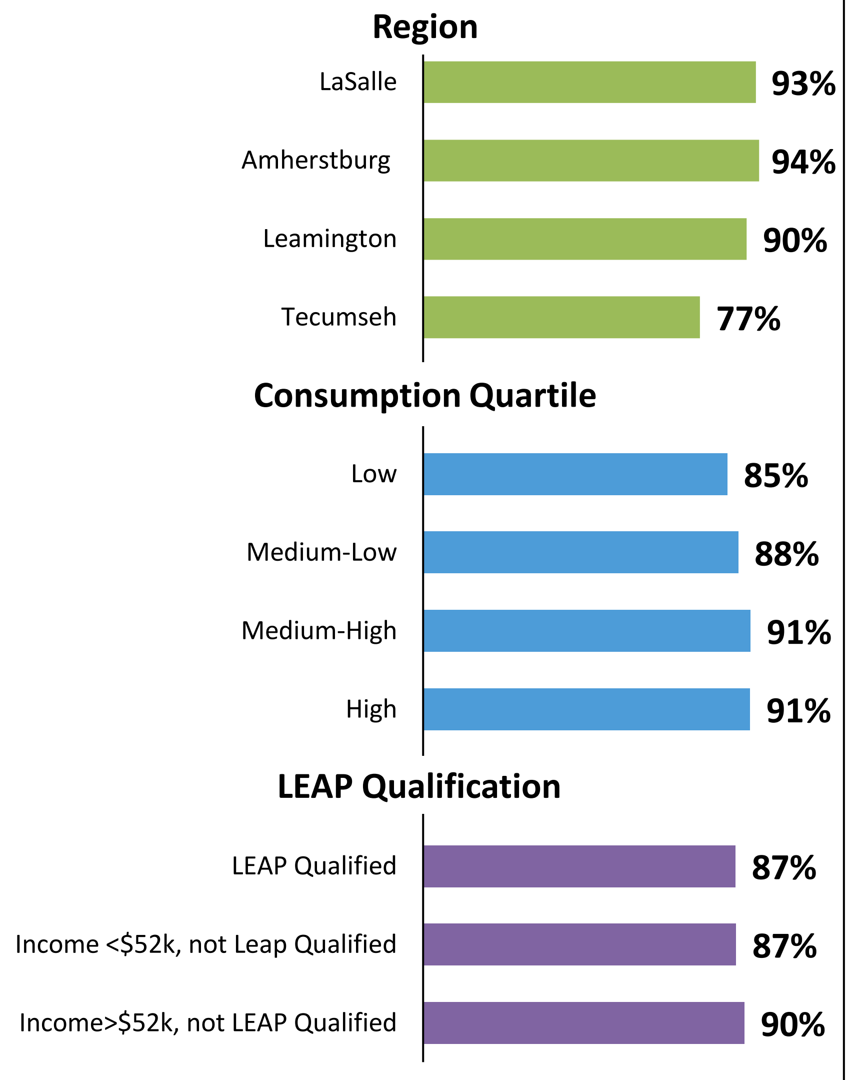
9-in-10 say they have experienced an outage in the last 12 months; lowest in Tecumseh (77%)

Q [Have you/Has your organization] experienced any power outages **in the past 12 months**, and if so, approximately how many?
[asked of all respondents; n=1,850]



Small Business (GS<50)
18/21 say they have experienced an outage.

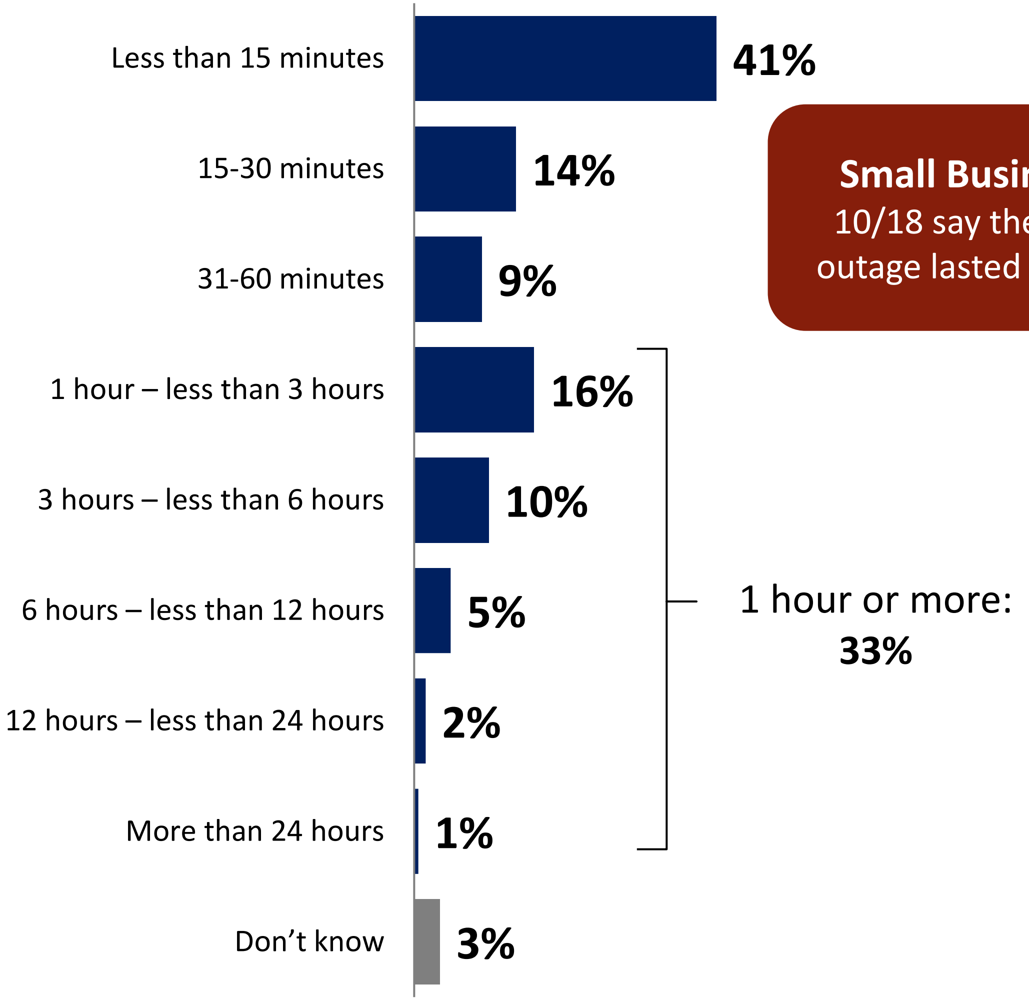
Segmentation
Respondents who "Experienced an Outage"



Length of Recent Power Outage

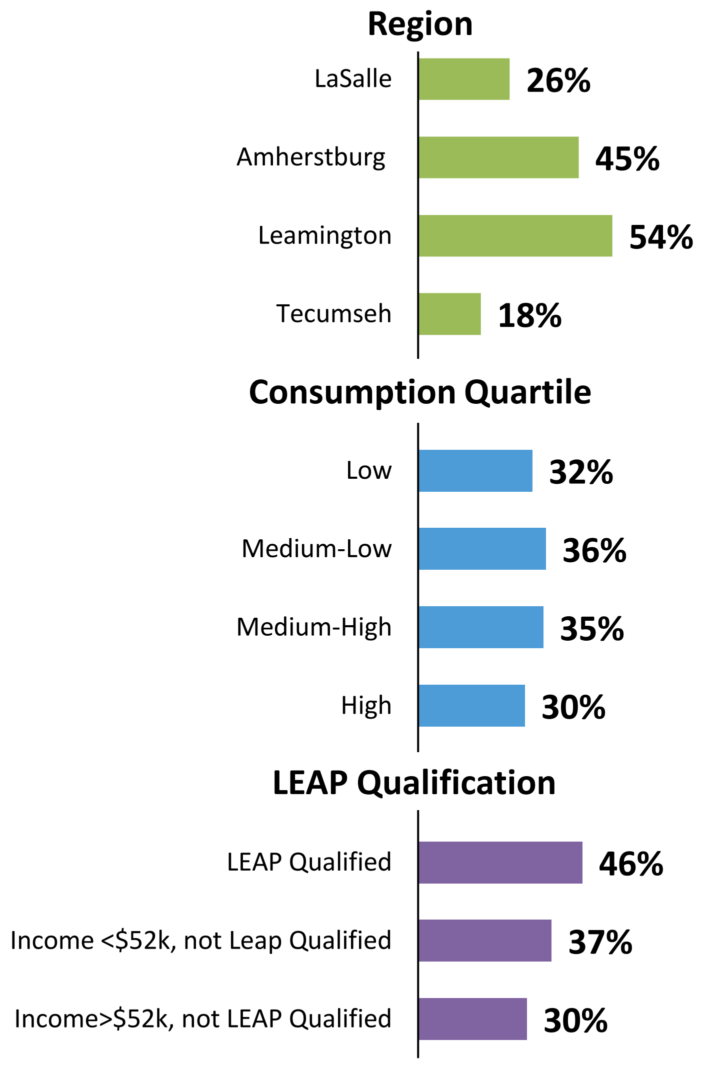
A plurality say their latest outage lasted <15 minutes; those in Leamington most likely to have prolonged outage

Q And approximately how many minutes or hours did the **most recent** power outage last?
[asked of all respondents who experienced an outage; n=1,645]



Small Business (GS<50)
10/18 say their most recent outage lasted 1 hour or more.

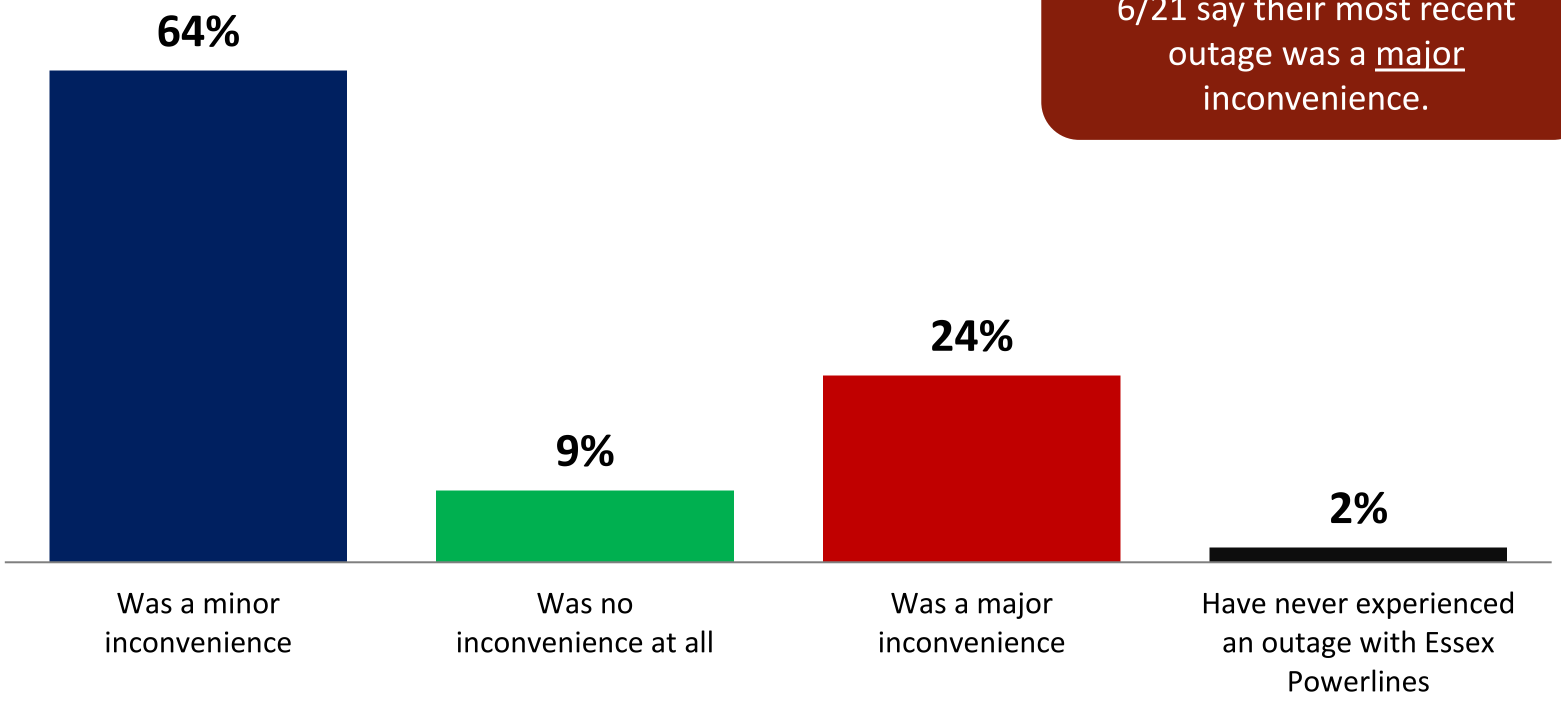
Segmentation
Respondents who say "1 hour or more"



Inconvenience of Outage

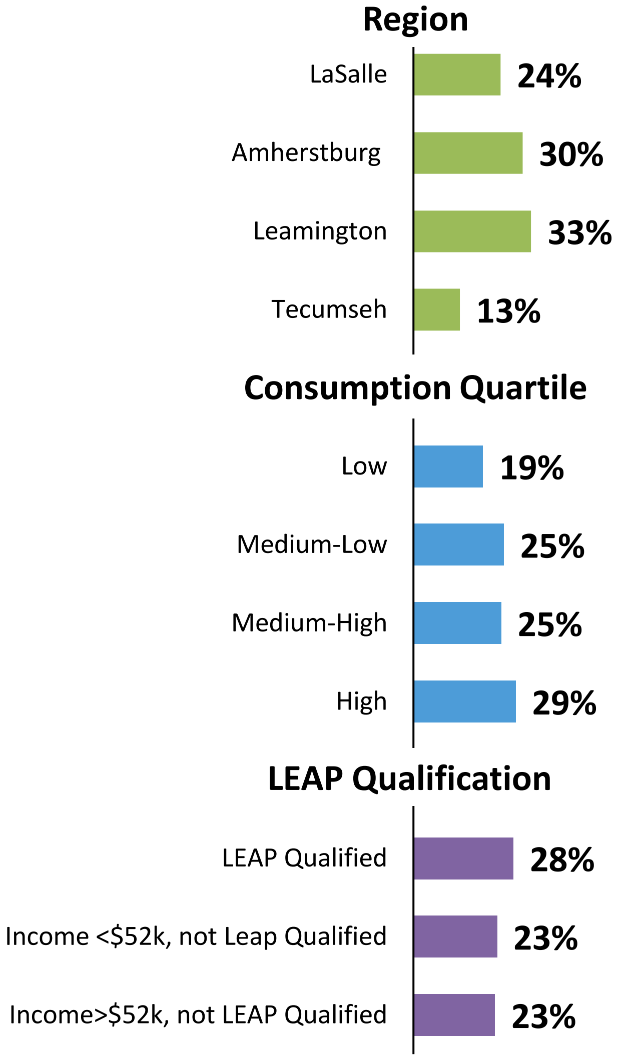
2-in-3 say their latest outage was a minor inconvenience while 1-in-4 say it was a major inconvenience

Q Thinking back to the **most recent** power outage you experienced as an **Essex Powerlines** customer, would you say the power outage…
[asked of all respondents; n=1,850]



Small Business (GS<50)
6/21 say their most recent outage was a major inconvenience.

Segmentation
Respondents who say "Major inconvenience"

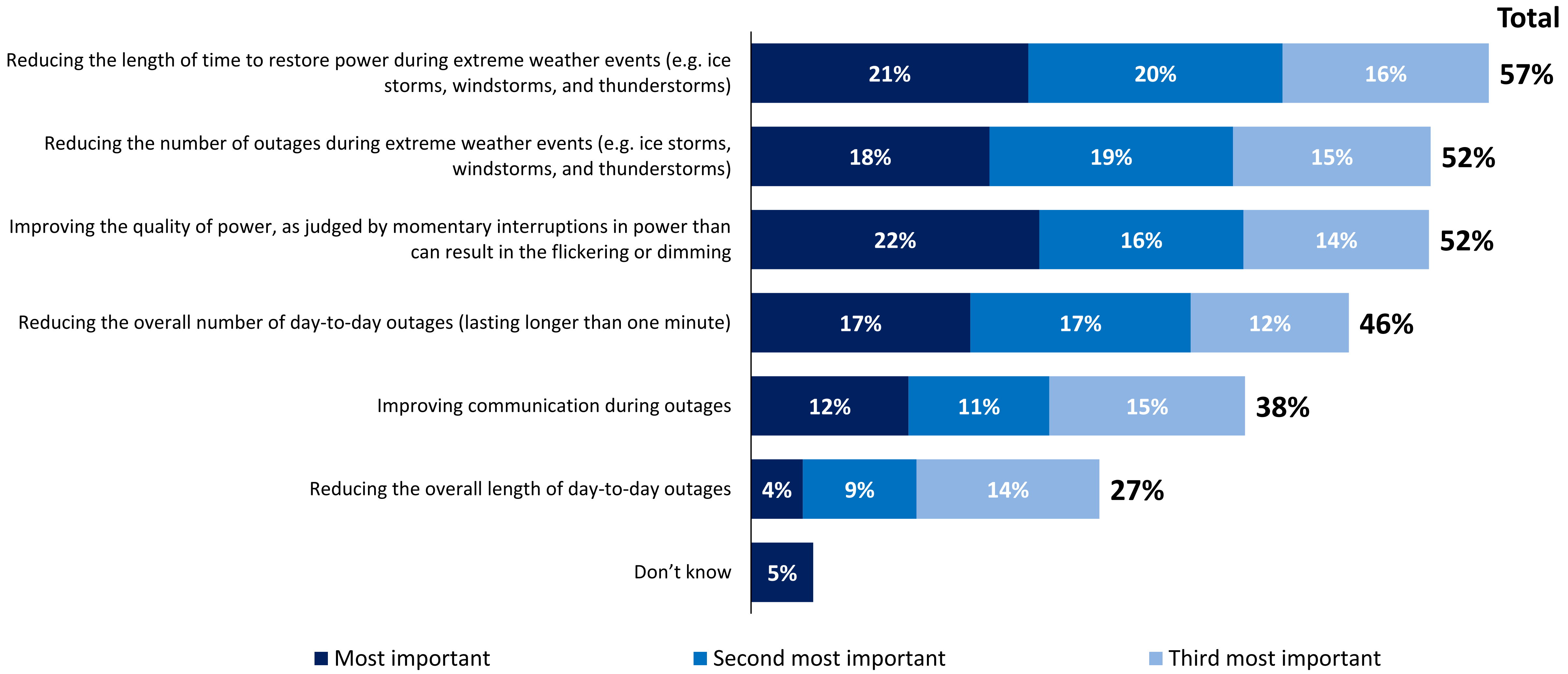


Ranking Reliability Priorities

Top reliability priority is reducing restoration time during extreme weather

Small Business (GS<50)
6/21 rank 'reducing the length of time to restore power during extreme weather events' as their top priority.

Q Among the following reliability outcomes, please indicate which one is most important to [you/your organization]. What is the next most important reliability outcome you think **Essex Powerlines** should focus on? And what do you consider the third most important reliability priority?
[asked of all respondents; n=1,850]



Ranking Reliability Priorities by Segments

The top priority for those in LaSalle is improving quality of power

Q Among the following **Essex Powerlines** priorities, please indicate which one is most important to you. What is the next most important priority you think Essex Powerlines should focus on? And what do you consider the third most important priority?
[asked of all respondents; n=1,850]

% Select as top three priority	Region				Consumption Quartiles				LEAP Qualification		
	LaSalle	Amherst-burg	Leaming-ton	Tecumseh	Low	Medium-Low	Medium-High	High	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified
Reducing the length of time to restore power during extreme weather events	52%	60%	67%	54%	60%	55%	57%	56%	57%	57%	57%
Reducing the number of outages during extreme weather events	52%	48%	57%	52%	54%	49%	54%	52%	61%	52%	53%
Improving the quality of power, as judged by momentary interruptions in power than can result in the flickering or dimming of lights	61%	50%	38%	51%	46%	53%	53%	58%	43%	47%	57%
Reducing the overall number of day-to-day outages	54%	53%	32%	41%	39%	47%	51%	48%	27%	42%	50%
Improving communication during outages	32%	41%	44%	42%	41%	38%	40%	34%	49%	39%	37%
Reducing the overall length of day-to-day outages	31%	28%	23%	22%	25%	29%	26%	28%	25%	27%	27%

Ranking New Technology Priorities

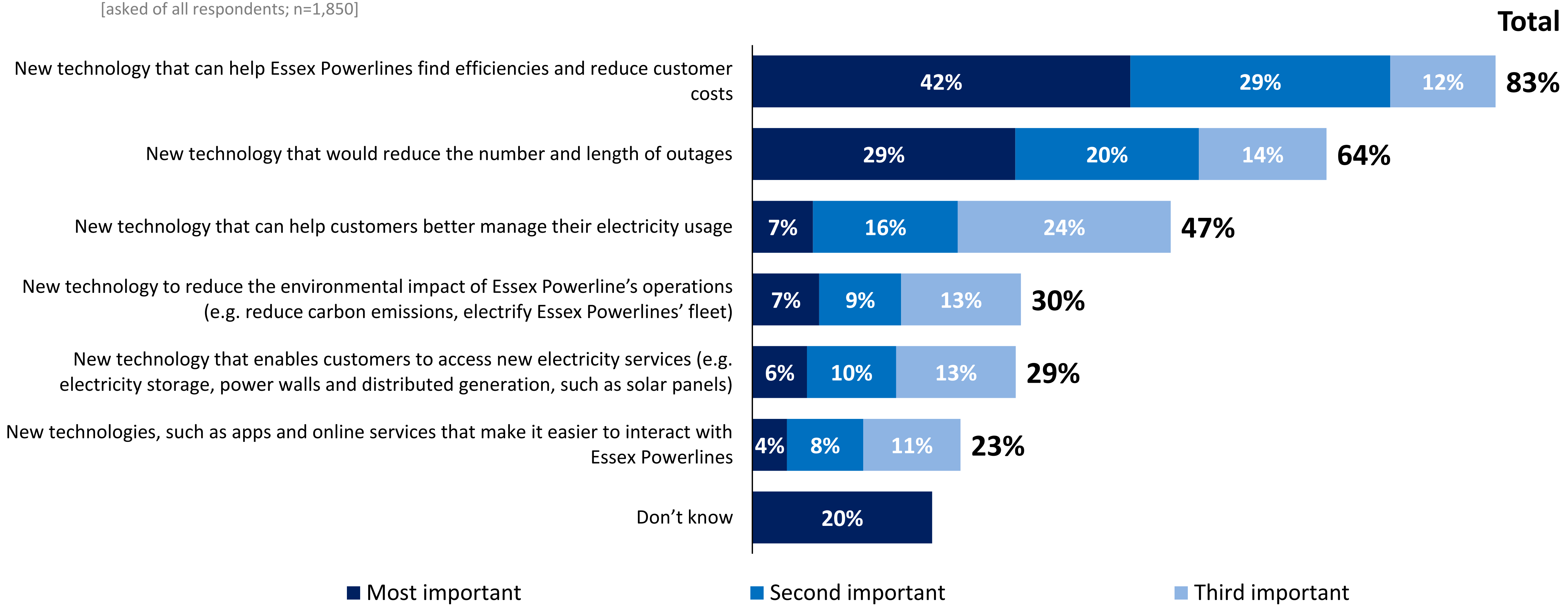
Tech to find efficiencies/reduce costs is clear top priority

Small Business (GS<50)
6/21 rank 'new technology that would reduce the number and length of outages' as their top priority. Another 6/21 say 'new technology that can help find efficiencies and reduce customer costs'.

Q

Investments in new technology can help **Essex Powerlines** address a range of issues. These include reliability, efficiency, customer service, **Essex Powerlines**' impact on the environment, new service offerings and tools to manage electricity usage.

Among the following potential investments in new technology, which would you say is the **most** important? What is the next most important new technology priority you think **Essex Powerlines** should focus on? And what do you consider the third most important priority?
[asked of all respondents; n=1,850]



Ranking New Technology Priorities by Segments

Across all segments, the top priority is tech that can help Essex find efficiencies and reduce costs

Q Among the following **Essex Powerlines** priorities, please indicate which one is most important to you. What is the next most important priority you think Essex Powerlines should focus on? And what do you consider the third most important priority?

[asked of all respondents; n=1,850]

% Select as top three priority	Region				Consumption Quartiles				LEAP Qualification		
	LaSalle	Amherst-burg	Leaming-ton	Tecumseh	Low	Medium-Low	Medium-High	High	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified
New technology that can help Essex Powerlines find efficiencies and reduce customer costs	84%	84%	78%	85%	82%	81%	86%	82%	72%	83%	83%
New technology that would reduce the number and length of outages	70%	68%	61%	52%	58%	64%	67%	67%	55%	59%	66%
New technology that can help customers better manage their electricity usage	47%	45%	39%	55%	47%	45%	47%	46%	43%	45%	48%
New technology to reduce the environmental impact of Essex Powerline's operations	31%	23%	30%	31%	35%	33%	27%	24%	31%	35%	29%
New technology that enables customers to access new electricity services	28%	33%	31%	28%	26%	29%	31%	31%	31%	26%	33%
New technologies that make it easier to interact with Essex Powerlines	20%	27%	24%	25%	21%	23%	24%	25%	24%	19%	25%

Electrification

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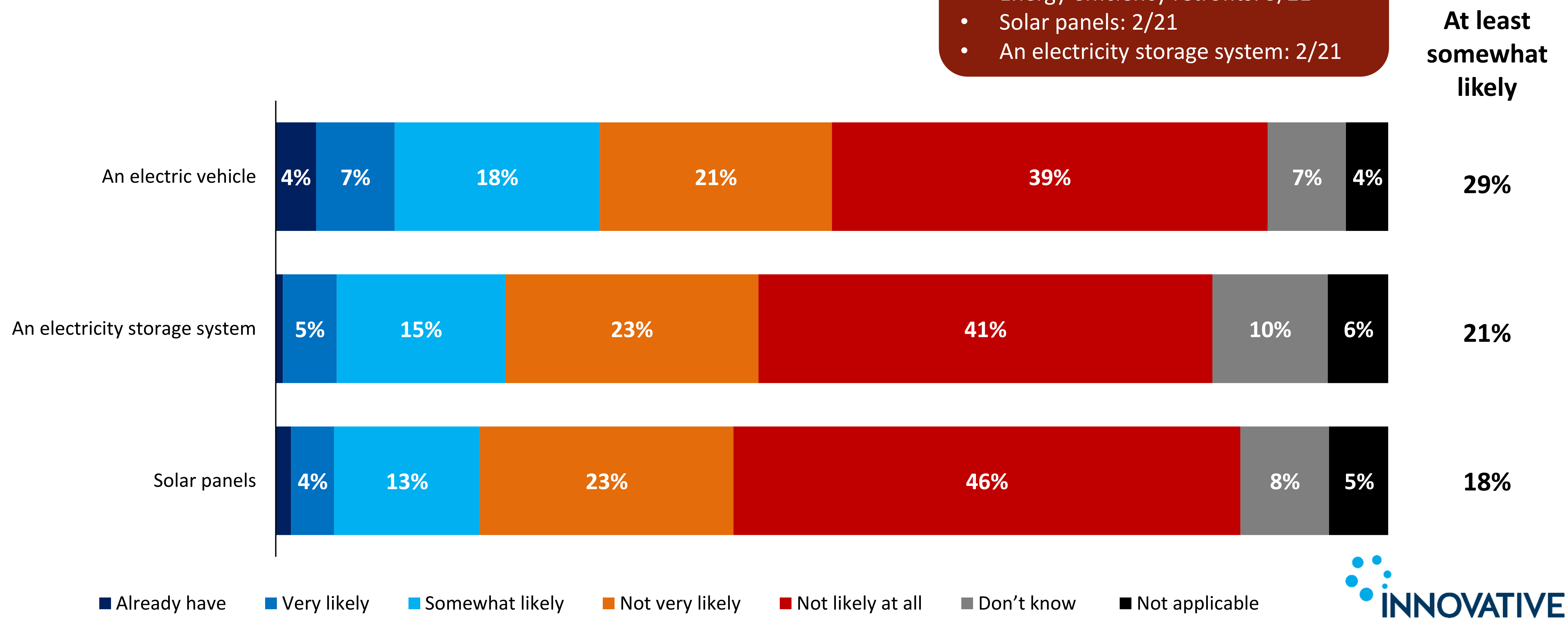
Electrification Investments

3-in-10 say they are at least somewhat likely to invest in an EV in the next five years

Q In the next five years, how likely or unlikely [are you/is your organization] to invest in the following:

[asked of all respondents; n=1,850]

Small Business (GS<50)
Total who say already have/very likely
- Energy efficiency retrofits: 5/21
- Solar panels: 2/21
- An electricity storage system: 2/21



Electrifications Investments by Segments

Higher consumption and higher income customers are more likely to consider electrification investments

Q In the next five years, how likely or unlikely are you to invest in the following:
[asked of all respondents; n=1,850]

At least somewhat likely	Region				Consumption Quartiles				LEAP Qualification		
	LaSalle	Amherstburg	Leamington	Tecumseh	Low	Medium-Low	Medium-High	High	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified
An electric vehicle	32%	21%	23%	34%	25%	28%	28%	36%	14%	19%	39%
An electricity storage system	18%	19%	25%	22%	17%	20%	20%	25%	16%	20%	25%
Solar panels	16%	17%	20%	22%	16%	17%	18%	22%	16%	18%	22%

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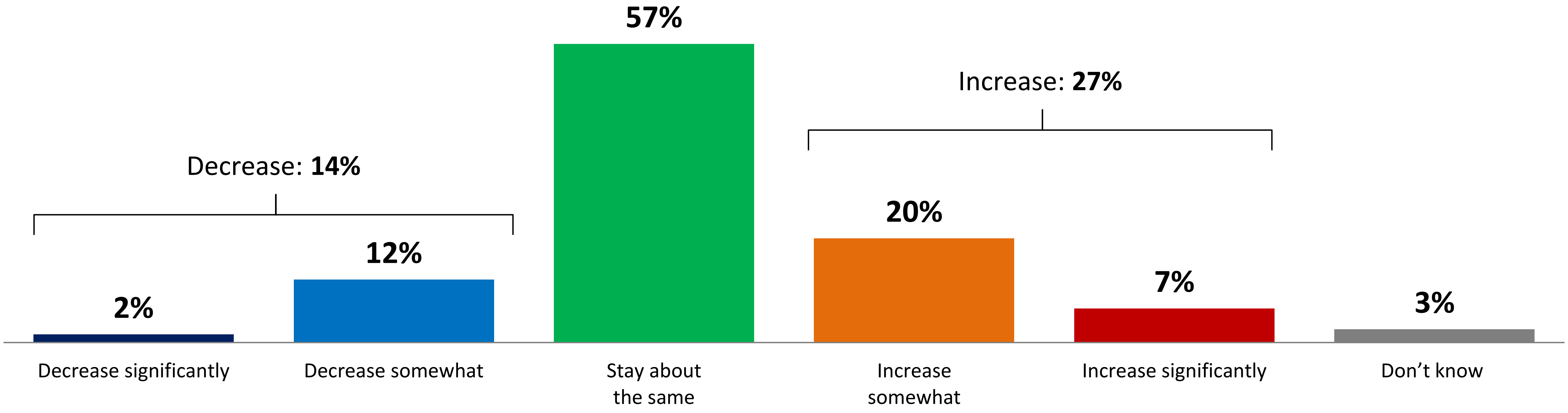
Electricity Usage

Most (57%) expect their electricity usage to stay the same over the next 10 years

Q Over the next 10 years, do you anticipate that [your/your organization’s] electricity usage will increase, decrease, or stay about the same?
[asked of all respondents; n=1,850]

Small Business (GS<50)
11/21 say they expect their usage to increase and 0/21 say they expect their usage to decrease.



Electricity Usage by Segments

Across the segments, customers are about equally likely to expect their electricity usage to increase

Q

Over the next 10 years, do you anticipate that your electricity usage will increase, decrease, or stay about the same?
[asked of all respondents; n=1,850]

	Region				Consumption Quartiles				LEAP Qualification		
	LaSalle	Amherstburg	Leamington	Tecumseh	Low	Medium-Low	Medium-High	High	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified
Decrease	13%	17%	12%	14%	8%	13%	14%	20%	10%	12%	15%
Stay about the same	58%	58%	58%	55%	62%	58%	59%	50%	58%	57%	55%
Increase	27%	23%	26%	29%	27%	27%	25%	27%	26%	29%	28%

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Customer Experience

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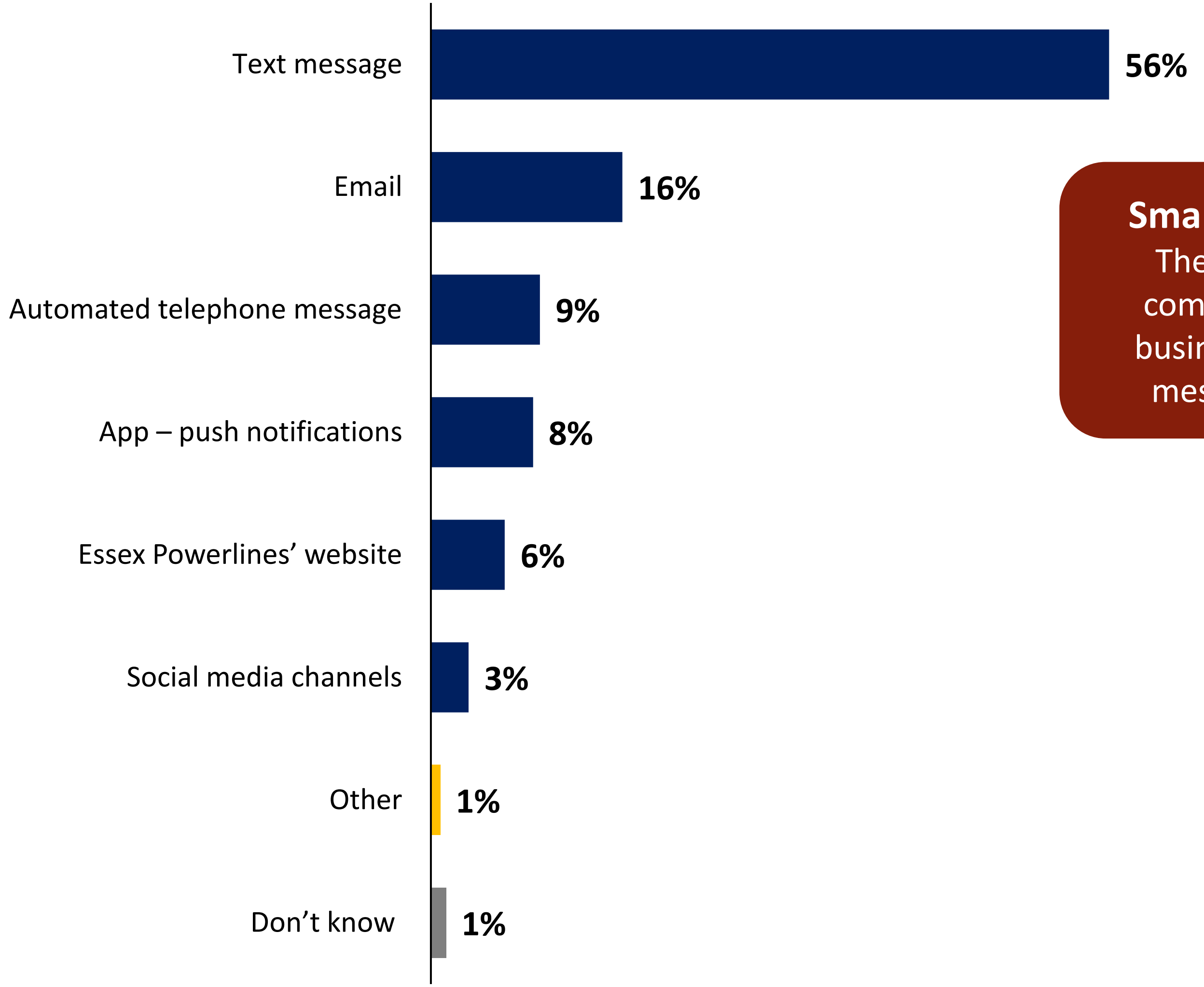
Communicate Outage Information

Text message is, by far, the top way customers prefer to receive outage information

Q

There are a number of ways that Essex Powerlines could communicate outage information to customers. What is the **best way** to communicate outage information to [you/your organization]?

[asked of all respondents; n=1,850]



Small Business (GS<50)
The top form of outage communication for small business customers is text message (11/21 select).

Communicate Outage Information by Segments

Across all segments text message is the clear top form of communication for outage information

Q

There are a number of ways that Essex Powerlines could communicate outage information to customers.
What is the **best way** to communicate outage information to you?
[asked of all respondents; n=1,850]

% Selected	Region				Consumption Quartiles				LEAP Qualification		
	LaSalle	Amherstburg	Leamington	Tecumseh	Low	Medium-Low	Medium-High	High	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified
Text message	57%	55%	53%	57%	52%	49%	60%	61%	57%	52%	62%
Email	15%	15%	19%	15%	19%	18%	12%	14%	19%	19%	13%
Automated telephone message	7%	13%	7%	11%	13%	12%	6%	5%	9%	14%	5%
App – push notifications	9%	8%	7%	8%	6%	7%	10%	10%	4%	5%	11%
Essex Powerlines' website	6%	6%	9%	4%	6%	7%	6%	5%	3%	6%	5%
Social media channels	4%	2%	3%	3%	2%	3%	3%	4%	2%	3%	3%

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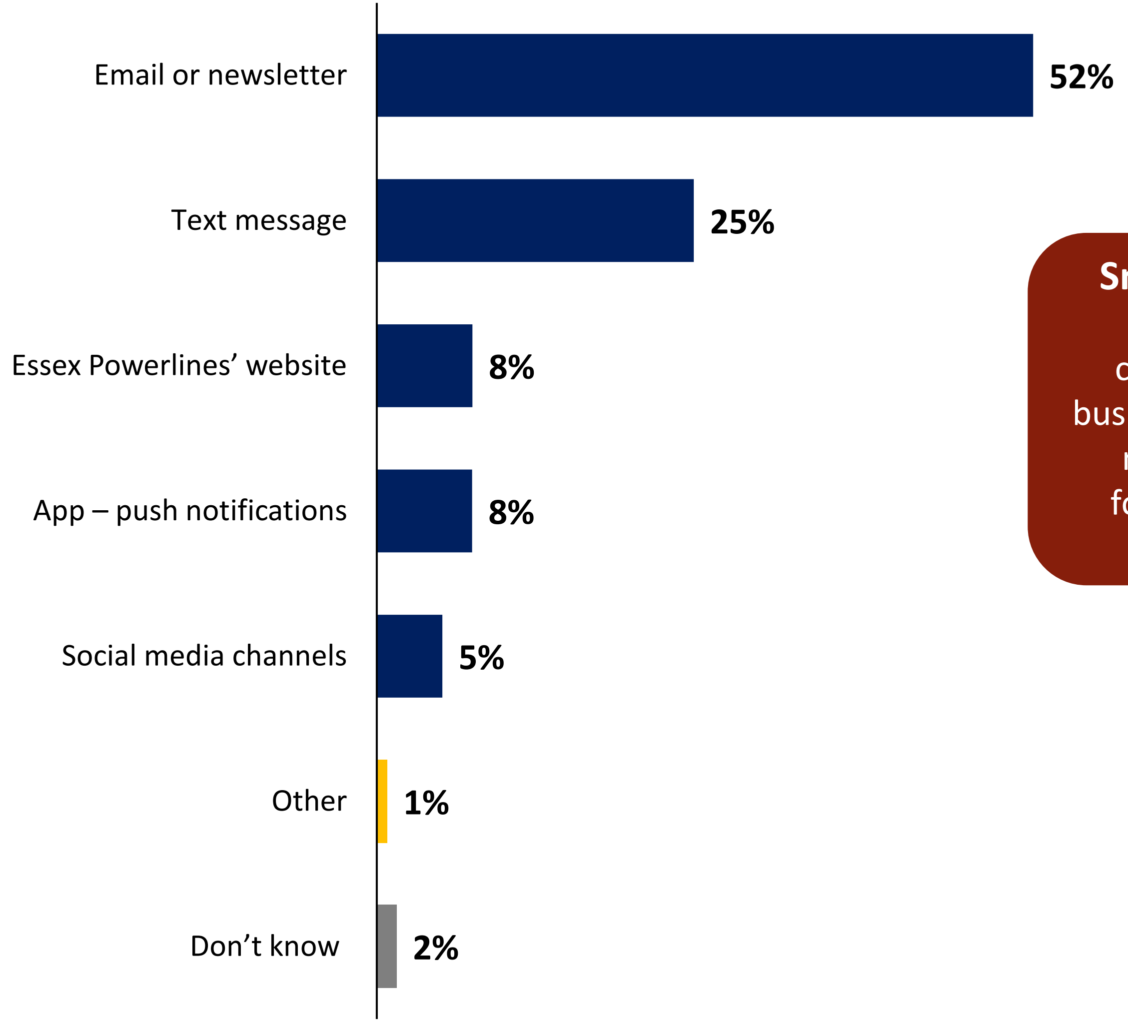
Communicate Other Information

Half (52%) select email/newsletter as the top form of communication for other information unrelated to outages

Q

And beyond outage information, what is the **best way** for Essex Powerlines to communicate other news or information to [you/your organization]?
[asked of all respondents; n=1,850]



Small Business (GS<50)
The top form of other communication for small business customers is email or newsletter (8/21 select) followed by text message (7/21 select).

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Communicate Other Information by Segments

LEAP qualified respondents are most likely to select text messages as their top form of communication

Q There are a number of ways that Essex Powerlines could communicate outage information to customers.
What is the **best way** to communicate outage information to you?
[asked of all respondents; n=1,850]

% Selected	Region				Consumption Quartiles				LEAP Qualification		
	LaSalle	Amherstburg	Leamington	Tecumseh	Low	Medium-Low	Medium-High	High	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified
Email or newsletter	53%	50%	50%	53%	56%	52%	53%	48%	41%	50%	54%
Text message	23%	27%	28%	25%	25%	23%	25%	28%	38%	30%	23%
Essex Powerlines' website	8%	6%	8%	7%	7%	10%	7%	7%	10%	6%	6%
App – push notifications	8%	8%	6%	8%	5%	9%	7%	10%	4%	5%	11%
Social media channels	6%	4%	5%	5%	5%	5%	6%	5%	4%	6%	6%

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Environmental Controls

INNOVATIVE RESEARCH GROUP

Environmental Controls: Uncontrollable External Factors

It is important to distinguish between what is within, and what is outside of an electrical utility's influence or control when it comes to drivers of satisfaction.

Perceptions of electricity companies often tend to move with **general confidence in Ontario's electricity sector**, rather than in response to the utility itself.

In addition, perceptions of utilities are strongly correlated with **financial circumstances**. In tough times, perception and preference can change because customers are struggling with their bills, not because of anything the company has – or as not – done.

Control questions help distributors distinguish between two factors that impact public perception:

a) utility-driven programs; and

b) uncontrollable external factors.

In this survey, we include two environmental control questions to help capture external phenomena:

Sector Confidence: *Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario.*

Financial Circumstances:
RES: *The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities.*
GS*: The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off.*

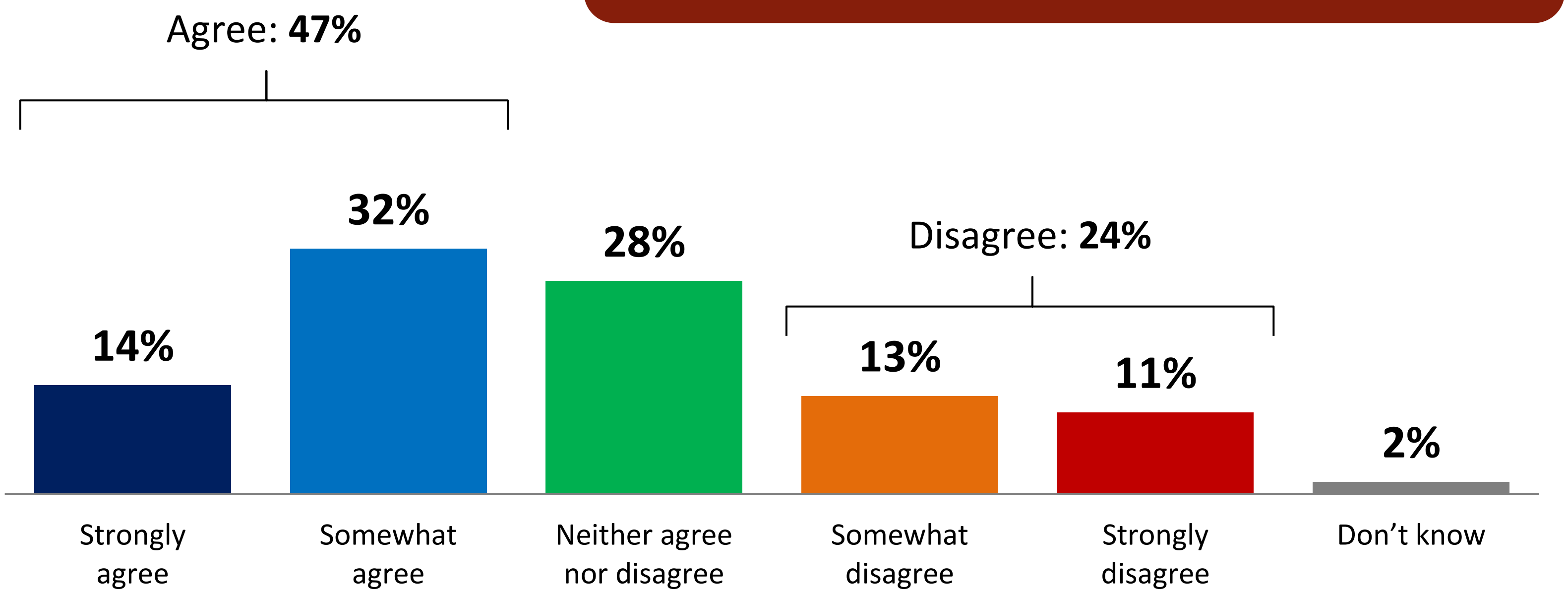
Financial Circumstances

Higher consumption and lower income customers are more likely to agree their bill has a major financial impact

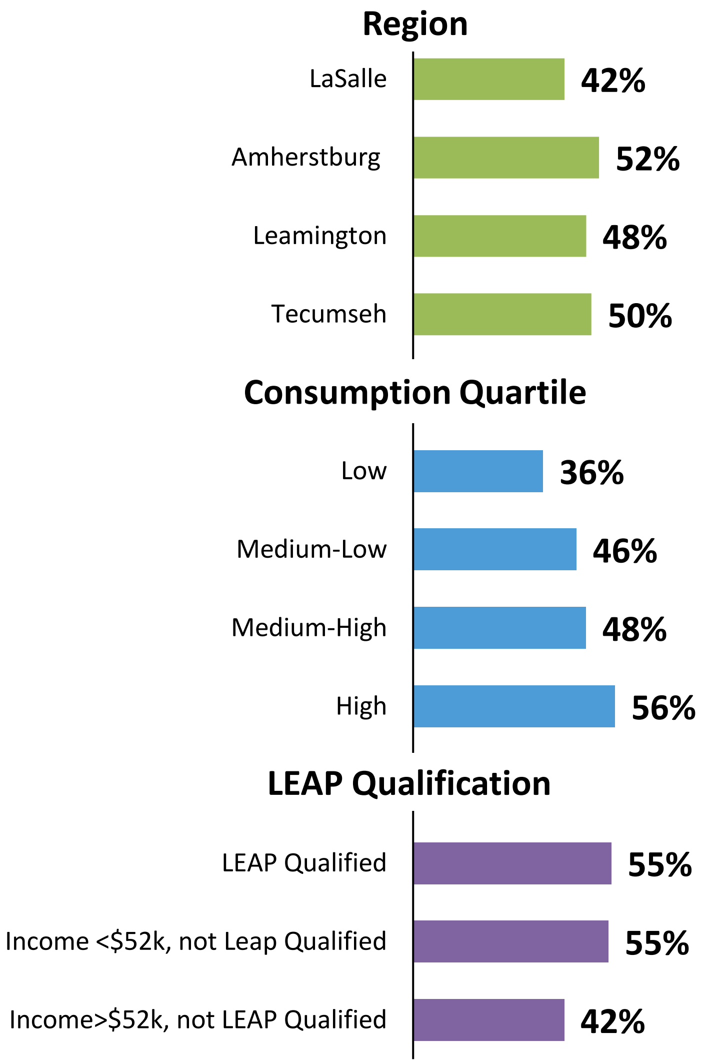
Q

To what extent do you agree or disagree with the following statements?
RES: ***The cost of my electricity bill has a major impact on my finances and requires I do without some other important priorities***
SB: ***The cost of my electricity bill has a major impact on the bottom line of my organization and results in some important spending priorities and investments being put off***
[asked of all respondents; n=1,850]

Small Business (GS<50)
17/21 small business customers agree and 4/21 disagree.



Segmentation
Respondents who say "Agree"



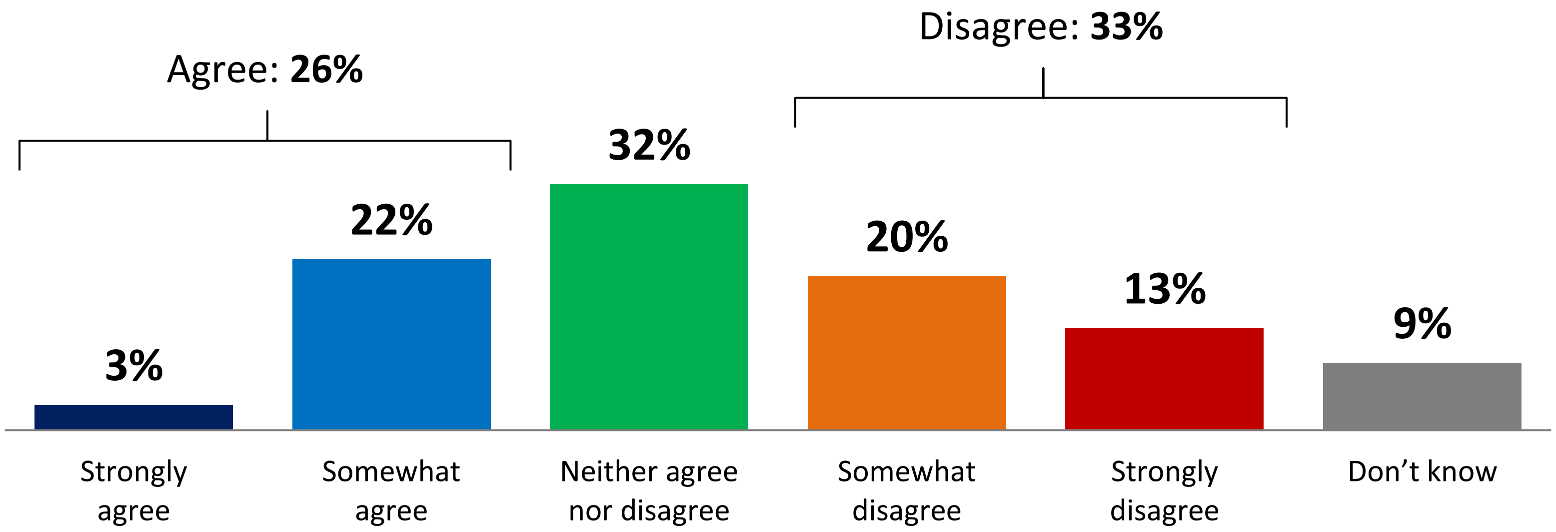
Sector Confidence

1-in-4 agree consumers are well-protected while 1-in-3 disagree

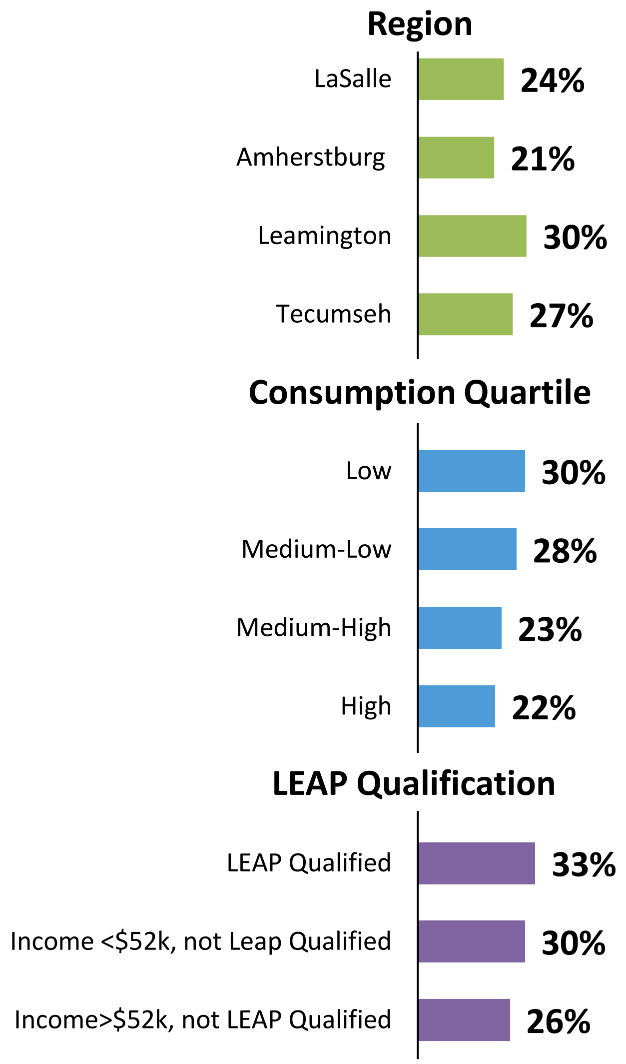
Q

To what extent do you agree or disagree with the following statements?
Consumers are well-protected with respect to prices and the reliability and quality of electricity service in Ontario
[asked of all respondents; n=1,850]

Small Business (GS<50)
7/21 small business customers agree and 7/21 disagree.



Segmentation
Respondents who say "Agree"



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