Essex Powerlines Corporation

Distribution System Plan

2025 – 2029

April 2024

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LIST OF ACRONYMS

Acronym	Meaning
ACA	Asset Condition Assessment
AIP	Asset Investment Plan
AIS	Asset Investment Strategy
CAIDI	Customer Average Interruption Duration Index
CDM	Conservation Demand Management
CHI	Customer Hours Interrupted
CI	Customers Interrupted
DESN	Dual Element Spot Network
DSP	Distribution System Plan
EPLC	Essex Powerlines Corporation
ESA	Electrical Safety Authority
GIS	Geographic Information Systems
GS	General Service
HI	Health Index
HONI	Hydro One Networks Inc.
IESO	Independent Electricity System Operator
LDC	Local Distribution Company
LOS	Loss of Supply
MED	Major Event Detail
OEB	Ontario Energy Board
OH	Overhead
REG	Renewable Energy Generation
RRFE	Renewed Regulatory Framework for Electricity Distributors
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
SS	Switching Station
TS	Transformer Station
UG	Underground

5.2 DISTRIBUTION SYSTEM PLAN

Essex Powerlines Corporation ("EPLC" or Essex Powerlines) has prepared this Distribution System Plan (DSP) in accordance with the Ontario Energy Board's (OEB's) Chapter 5 – Distribution System Plan Filing Requirements for Electricity Distribution Rate Applications, dated December 2022 (the "Filing Requirements") as part of its 2025 Cost of Service Application (the Application).

The DSP is a stand-alone document that is filed in support of EPLC's Application. The DSP's duration is a minimum of ten years in total, comprising of a historical period and a forecast period. The DSP covers the historical period of 2018 to 2023, with 2024 being the bridge year, and a forecast period of 2025 to 2029, with 2025 being the Test Year.

The DSP contents are organized into three major sections:

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

The materiality threshold for EPLC is $90,000 and detailed descriptions of specific projects/programs exceeding the materiality threshold are provided in Section 5.4.2.1 and Appendix A. EPLC notes that it has chosen to provide explanations for variances below its materiality threshold, where these explanations were necessary for meaningful analysis. Other pertinent information relevant to this DSP is included in the Appendices.

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

5.2.1 DISTRIBUTION SYSTEM PLAN OVERVIEW

EPLC is a forward-thinking local distribution company that is responsible for distributing electricity to more than 34,000 business and residential customers within the Town of Amherstburg, the Town of LaSalle, the Town of Tecumseh, and the Municipality of Leamington. Essex Powerlines has continued to provide safe, reliable, and economical energy services to its customers since its inception in June 2000. This is EPLC's second consolidated Distribution System Plan ("DSP") prepared in accordance with Chapter 5 of the OEB's Filing Requirements for Electricity Distribution Rate Applications.

EPLC prides itself on providing excellent service to its customers, and 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"):

1. Customer Focus: services are provided in a manner that responds to identified customer preferences.
2. Operational Effectiveness: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives.
3. Public Policy Responsiveness: utilities deliver on obligations mandated by government; and
4. Financial Performance: financial viability is maintained; and savings from operational effectiveness are sustainable.

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.

5.2.1.1 Description of the Utility Company

Essex Powerlines Corporation ("EPLC) is a licensed electricity distributor (ED-2002-0499) by the Ontario Energy Board, who is responsible for distributing electricity to approximately 34,286 business and residential customers within its service territory. EPLC is a wholly owned subsidiary of Essex Power Corporation, which was formed on June 1, 2000, when the Town of Amherstburg, LaSalle, and Tecumseh and the Municipality of Leamington amalgamated their small utilities. Today, EPLC continues to provide value to its customers by providing a safe and reliable grid at affordable rates.

Essex Power Corporation is owned by four (4) municipally owned shareholders, and is the holding company of its subsidiary companies, Essex Powerlines Corporation and Essex Energy Corporation. Figure 5.2-1: Essex Power Corporation's Corporate Structure below illustrates Essex Power Corporation's corporate structure and its relationship with its four (4) respective shareholders, with equity percentages listed. While each shareholder may have different equity, they each hold equal voting rights.

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

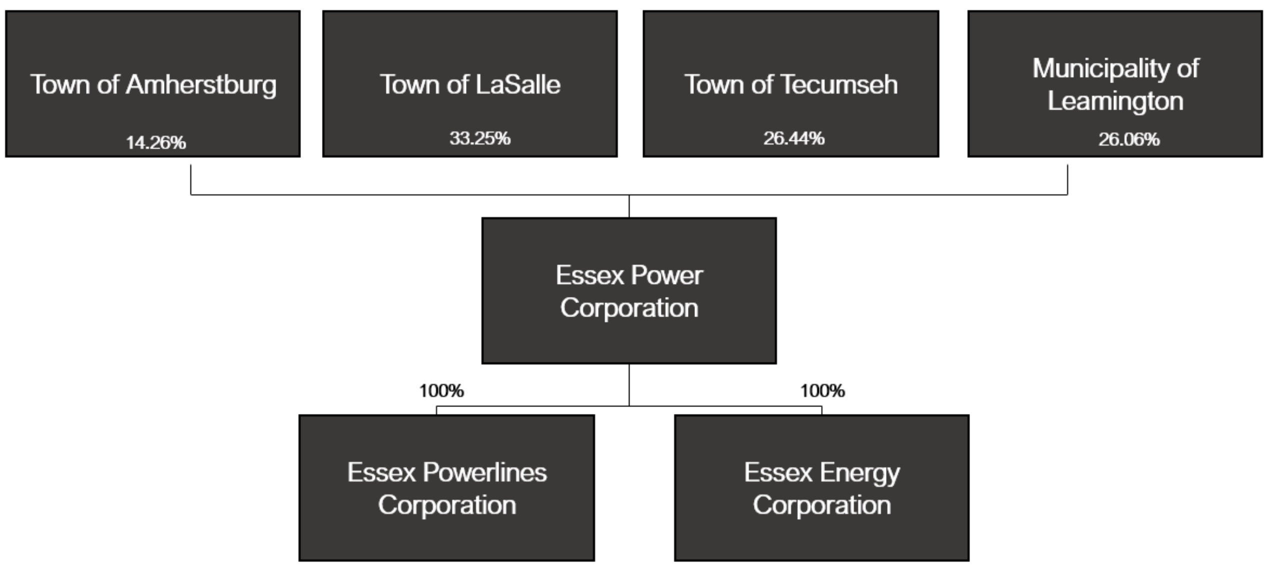

Figure 5.2-1: Essex Power Corporation's Corporate Structure

5.2.1.1.1 Service Area and Customers

EPLC's service area consists of four non-contiguous regions in Essex County located in south-western Ontario: The Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington, and the Town of Tecumseh. Figure 5.2-2 depicts the County of Essex with EPLC's service areas highlighted. The individual towns are geographically dispersed over a large area. EPLC is bordered by Hydro One Networks Inc. (HONI) in the south and east of Tecumseh and LaSalle, and the Leamington and Amherstburg service areas are completely encompassed by HONI. EPLC is also bordered by EnWin Utilities west of Tecumseh and north of LaSalle. ELK Energy does not directly border EPLC's service areas, but also distributes electricity in the County of Essex.

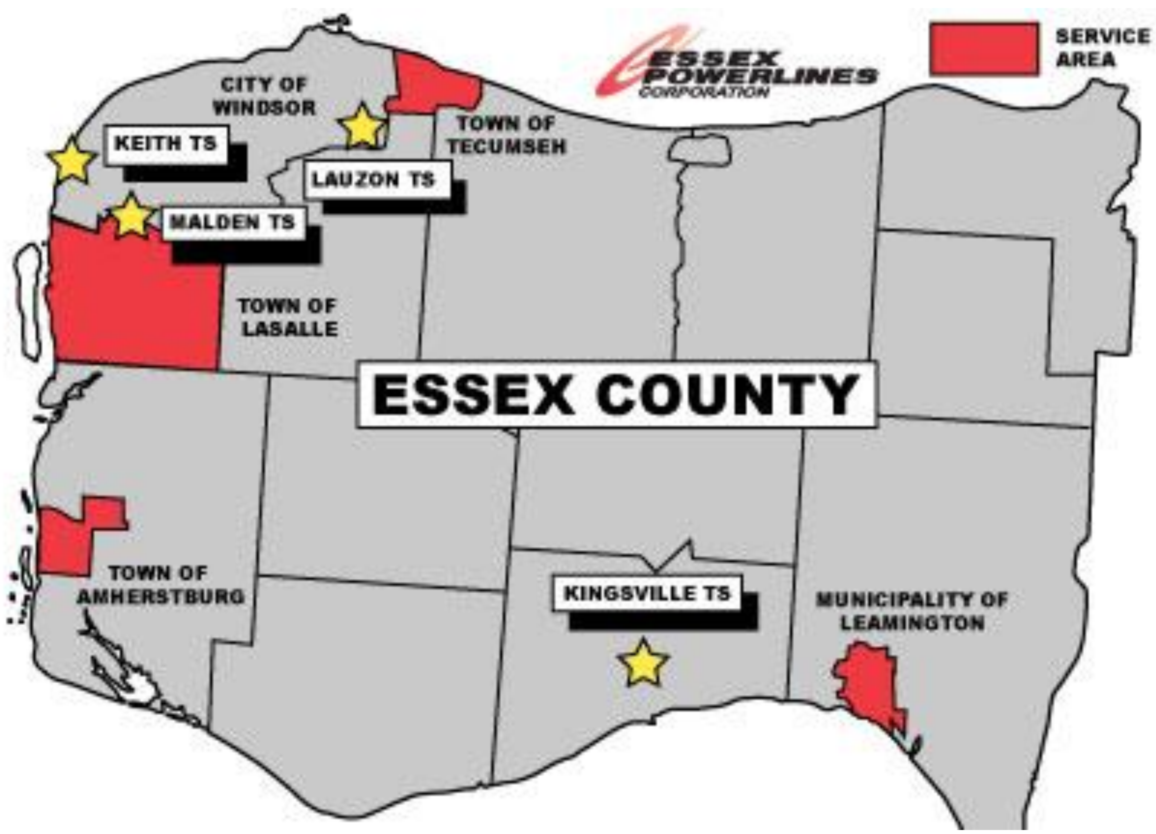

Figure 5.2-2: EPLC's Non-Contiguous Service Areas

EPLC serves just over 34,000 customers, with around 29,000 residential customers and over 5,000 small and large commercial customers.

5.2.1.1.2 Mission, Vision, Values and Goals

EPLC's mission and vision statements are presented below:

Mission Statement:

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".

Vision Statement:

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.

Corporate Values

EPLC's capital investment strategy is driven by its corporate values. EPLC's business plan and objectives are centered around three (3) primary themes:

- Customer Focus - EPLC's customer-centric culture is evident through ongoing customer engagement activities and community outreach including satisfaction and safety surveys; technology solutions leveraged to enhance the customer experience, and an omni-channel approach to communication and feedback through multiple outlets. As EPLC's customer base continues to grow, EPLC must remain vigilant in planning and executing all activities through the lens of customer satisfaction n.
- Reliability- 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. It is essential that EPLC plans for additional capacity requirements and rises to the challenges that will be faced in the near future.
- Power Growth - EPLC is focused on activities 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 requires innovation and investments in scalable technologies that will enable EPLC to meet increasing demand both flexibly and seamlessly.

These themes define how EPLC will 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.

EPLC's mandate is to implement the items above, which will have material benefits for customers, all while maintaining reasonable distribution rates. As such, EPLC has identified six (6) core corporate values:

1. Customer & Community Value;
2. Operational Excellence;
3. Safety;
4. Employee Satisfaction;
5. Reasonable Rates; and

6. Financial & Environmental Sustainability.

Figure 5.2-3 relates to EPLC's corporate values to RRFE objectives.

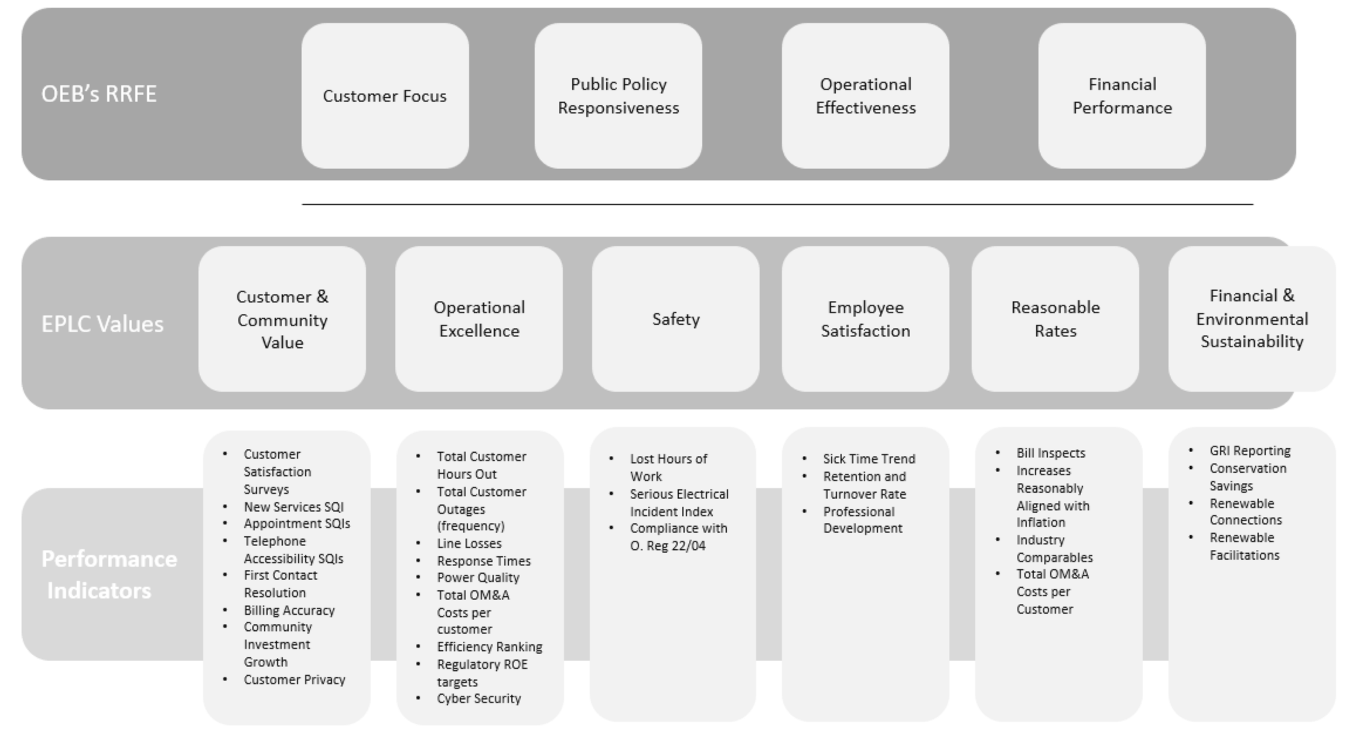

Figure 5.2-3: EPLC Corporate Values

Customer & Community Value
EPLC's core value of driving Customer & Community Value is defined as follows:

"EPLC is dedicated to meeting and exceeding customer & community needs by providing services that are cost effective and put the needs of its customers first."

This value can be tied to the OEB's RRFE outcomes of Customer Focus and Public Policy Responsiveness.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Customer Satisfaction Surveys.
- Continuous engagement through an omni-channel solution, including social media, chatbot, email, and phone, among others .
- Investing back in each of the four (4) shareholder communities through various charitable organizations.
- Investing in tools and technologies to enhance the customer experience; and
- Maintaining just and reasonable rates.

Operational Excellence
EPLC's core value of delivering Operational Excellence is defined as follows:

"EPLC strives for Operational Excellence through all services that it provides by advocating continuous improvement and implementing Best-In-Class and cost-effective solutions that deliver customer value."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness and Public Policy Responsiveness.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Development of EPLC's DSP.
- Implementing best-in-class solutions and shared services.
- Facilitating the self-healing grid.
- Successful and cost-effective implementation of public policy initiatives such as Tiered billing, Ultra Low Rates, and Green Button Initiative.
- Continuing to implement innovative solutions that enable consumer choice and improve the grid system.
- Demonstrating value in non-wires solutions through local energy markets, and
- Maintaining just and reasonable rates.

Safety
EPLC's core value of advocating the importance of Safety across its entire operation can be defined as follows:

"EPLC is committed to a Safety-First mentality across its entire operation."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness and Public Policy Responsiveness.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Joint Health & Safety Committee.
- First Aid, CPR, and defibrillator training.
- Specialized Safety Training; and
- School Electrical Safety Awareness.

Employee Satisfaction
EPLC's core value of driving Employee Satisfaction is defined as follows:

"EPLC is committed to encouraging and developing engaged and empowered employees."

This value can be tied to the OEB's RRFE outcome of Operational Effectiveness.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Wellness Committee.
- Employee Assistance Program.
- Corporate Charity Events.
- Employee Recognition; and
- Corporate Team-Building Events.

Reasonable Rates
EPLC's core value of maintaining Reasonable Rates is defined as follows:

"EPLC will implement Best-In-Class technologies and solutions to provide our employees with the necessary information to make prudent decisions, control costs and minimize interruptions while providing reasonable rates for our electricity customers."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness and Financial Performance.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Maintaining just and reasonable rates.
- Prudent Investments in Smart Grid technology.
- Investments in innovation to unlock non-wires alternative solutions; and
- Controllable Costs per customer in line with leaders in Ontario.

Financial & Environmental Sustainability
EPLC's core value of championing Financial & Environmental Sustainability is defined as follows:

"EPLC strives to achieve balanced economic, social and environmental returns that ensure the future viability of our company for the benefit and well-being of our shareholders and the communities we serve."

This value can be tied to the OEB's RRFE outcomes of Operational Effectiveness, Customer Focus, and Financial Performance.

Examples of EPLC's commitment to this value can be demonstrated as follows:

- Yearly Global Reporting Initiative sustainability reporting.
- Investing in renewable energy technology.
- Investing in innovative technology solutions that enable customer choice as it relates to electrification and conservation efforts.
- Exploring Distribution System Operator (DSO) activities and structure to enable NWAs.
- Facilitating REG connections; and
- Maintaining just and reasonable rates.

5.2.1.2 Capital Investment Highlights

EPLC's capital investments over the planning period have been aligned to the four categories of system access, system renewal, system service, and general plant outlined in the Filing Requirements. Table 5.2-1 presents EPLC's historical actuals and forecast expenditures for both capital and O&M categories.

Table 5.2-1: Historical and Forecast Capital Expenditures and System O&M ($ '000)

Category	Historical						Bridge	Forecast				
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
System Access (Gross)	2031	1615	1164	1629	2816	3903	2400	2314	2348	2395	2443	2492
System Renewal (Gross)	2848	3940	2858	3020	2358	2549	2088	3214	2973	2470	3436	3206
System Service (Gross)	900	642	899	584	814	1447	3358	2532	2804	5666	4772	4848
General Plant (Gross)	619	781	971	1267	1440	3093	2901	3244	2382	2280	2013	1824
Gross Capital Expenses	6398	6978	5892	6500	7428	10992	10747	11303	10506	12809	12664	12371
Contributed Capital	-1167	-808	-652	-1201	-1634	-3313	-1439	-1468	-1497	-1527	-1558	-1589
Net Capital Expenses after Contributions	5231	6170	5240	5299	5794	7679	9308	9835	9009	11283	11106	10781
System O&M	2240	2426	2615	2526	2473	2706	2820	3189	3235	3344	3245	3265

** Forecast expenditures are included in 2024. Note there may be minor errors in the number due to rounding.*

5.2.1.2.1 System Access

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

- the connection of residential, commercial, and industrial customers,
- connection of subdivision and townhouse lots, and
- municipal driven projects.

Municipal driven projects have varying annual impacts on System Access spending in the DSP. Future changes to municipal plans and projects within the period of the DSP may require reallocation of resources to System Access spending from other capital investments.

5.2.1.2.2 System Renewal

System Renewal investments are driven by the need to address assets that are at risk of failure and therefore could have a negative impact on reliability. EPLC uses the outputs of its Asset Condition Assessment as a key input into its planning process, which is described further in section 5.3.1, to inform what system renewal investments are required to be carried out. Details on EPLC's ACA can be found in section 5.3.2.2.2 and Appendix B. Proactive replacement plans ensure that planning objectives related to reliability, customer satisfaction, and operating cost control are achieved.

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

- Pole Replacement program: this program will address poles that are showing significant deterioration. This is a continuation of an annual program EPLC has been carrying out historically.
- Overhead and Underground Infrastructure Programs: - as identified through the ACA, EPLC has OH and UG assets that should be considered for replacement in the next five years. This covers both OH conductor, UG cable, and the associated transformers.
- Reactive Programs – This program allocates capital for reactive capital projects because of unplanned events.
- Unresolved PM/IR/HealthMAP/SmartMAP – Capital Overhead and Underground – This includes small capital investments required that have been identified through preventative maintenance activities.
- Misc. Capital Costs –This small expenditure category includes investments for small remedial work and other minor ad-hoc investments that were not originally planned for.

5.2.1.2.3 System Service

System service investments over the forecast period are driven by system expansions due to asset acquisitions, system expansions to enable REG investments, and investments into reclosers as part of a self-healing grid to improve system reliability and decrease outage restoration costs.

Over the forecast period EPLC has the following major programs/projects it will carry out:

- A continuation of its Self-Healing Grid program to install fault indicators and reclosers within EPLC's distribution system, enhancing distribution automation capabilities. Fault indicators will be installed at strategic locations to provide early detection of any outages happening. This allows EPLC to respond quickly and minimize any impacts to its downstream customers. Reclosers will be added to enhance sectionalizing, fault identification and restoration.
- Network upgrades from 100A to 200A to facilitate the increase in EV chargers and other devices being installed at residential locations.
- Metering investment to comply with Measurement Canada guidelines.
- Begin the deployment of an AMI 2.0 network, meters, and associated hardware/systems,
- Improving the operability of its system and the ability to manage the distribution system equipment that serves its customers through asset purchases from HONI. EPL has planned additional asset transfers as part of a broader strategy for both LDCs to manage and control the assets serving their respective customers.

Many of these investments help shape EPLC's strategy of becoming a distribution system operator (DSO) through grid modernization and automation efforts, while significantly improving reliability and safety of EPLC's system

5.2.1.2.4 General Plant

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

- Replace fleet vehicles based on the fleet condition assessment and needs of the vehicles for EPLC's operations.
- Implement building and office furniture investments based on inspections and condition assessments. EPLC is planning its next third-party assessment to begin in 2025. This will help refine and inform investments required for 2026 onwards.
- Annual investments into IT hardware and software to perform maintenance and cybersecurity enhancements, will enable EPLC staff to effectively perform activities such as billing and responding to customer queries in an efficient and reliable manner.

5.2.2 Key Changes since Last DSP Filing

This is EPLC's second DSP filing. The following items are key elements that have changed since EPLC's last DSP:

- Invested in and improved data quality with upgrades and implementation of industry software such as SmartMAP, GIS, DESS, HealthMAP, etc.

- Implementation of a Work Center- work-flow management system (including digital work packages)
- Made incremental improvements to asset management planning.
- Organizational changes that are allowing EPLC to better serve its customers.
- Implemented Cybersecurity Framework in compliance with the OEB's cyber security framework.
- Enhanced the consumer experience through new technologies, such as a new phone system and online chatbot, as well as updated EPLC's website for a better user experience and more concise information.
- Implemented an Outage Notification Centre for customers.
- Created a "Self-Healing Grid" through the implementation of smart technology in the field.
- The COVID-19 pandemic created challenges including supply chain issues and increased costs in materials and equipment.
- External factors, such as global inflation increases over the last few years have caused significant cost increases on materials, goods, and services related to EPLC's capital and operating costs.
- Business strategy and planning is heavily focused on the energy transition, such as enabling NWAs and electrification through infrastructure investments.

5.2.2.1 DSP Objectives

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

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

This DSP covers a planning horizon of five years starting in the 2025 test year. Employing this long-term approach requires EPLC to consider future customer needs and any required changes to its distribution system in advance. This approach enhances EPLC's ability to proactively plan and respond to evolving customer needs in a timely manner, while managing and leveling the impacts of expenditures on consumer rates to maintain affordability of its service. The DSP recognizes EPLC's responsibilities and commitments to provide customers with reliable service by ensuring that its asset management activities focus on the performance outcomes established in the OEB's Renewed Regulatory Framework for Electricity (RRFE):

1. **Customer Focus**: services are provided in a manner that responds to identified customer preferences;
2. **Operational Effectiveness**: continuous improvement in productivity and cost performance is achieved; and utilities deliver on system reliability and quality objectives;

3. **Public Policy Responsiveness**: utilities deliver on obligations mandated by government (e.g. in legislation and in regulatory requirements imposed further to Ministerial directives to the Board); and
4. **Financial Performance**: financial viability is maintained, and savings from operational effectiveness are sustainable.

In alignment with these four outcomes, EPLC's overarching objective of its five (5)-year plan is to modernize the distribution grid through innovative technologies and systems to increase grid reliability, improve network resilience, enhance the consumer experience through increased consumer choice, and realize operational efficiencies and cost savings to be passed down to ratepayers. To achieve the goals EPLC has set for itself, EPL continually strives to:

- Modernize its system, through the implementation of a self healing grid, in efforts to move towards becoming a Distribution System Operator (DSO).
- Continually look to drive costs down with the implementation of modern management techniques and other process improvements.
- Invest in advanced metering technology through its AMI 2.0 project to maintain billing accuracy, optimize network communications, reduce manual meter reads (only meters in an electrical room that blocks the signal from getting out would need manual reads), provide faster response times to disconnection/reconnection requests, provide more accurate outage information, and provide customers with a modern AMI platform to meet foreseeable customer needs over the lifetime of the assets.
- Invest in systems and software that permit ongoing improvements to distribution system analytics to realize short-, mid-, and long-term benefits, including but not limited to, outage management, distribution system planning and prioritization, and condition-based asset planning.
- Maintain and where required improve its reliability through the targeted and data driven investments to address assets that are at risk of failure within the next five years.
- Further develop its SmartMAP application with enhancements such as near-real time load forecasting, historical outage heatmaps, capacity heatmaps, weather integration/overlays, and the integration of SCADA systems power quality data. These additional elements will be reviewed, scoped, and developed over the next 5 years.
- Expand on collaborative work with other local distribution companies to realize synergies and cost efficiencies for projects such as the expansion of control room operations.
- Invest in automation to improve the overall customer experience and timeliness of interactions.

5.2.3 Coordinated Planning with Third Parties

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

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

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

5.2.3.1 Customers

EPLC has commissioned Innovative Research Group ("INNOVATIVE") to design and implement a Customer Satisfaction survey of EPLC's residential and GS<50 customers on its behalf in June 2023, and a Ratepayer Survey in November 2023.

Purpose of the Consultations

The purpose of the customer surveys is to measure customer satisfaction, determine customer needs and preferences, and identify opportunities to improve customer experience. The INNOVATIVE Customer Satisfaction Survey also educated participants about Ontario's distribution system, EPLC's role in delivering power to households and businesses, the interpretation of their electricity bill, and the potential for consumer choice through electrification and conservation. The most recent INNOVATIVE survey distinguished customers' willingness to pay for reliability improvements (including innovative technologies) and maintaining and improving the system grid.

Whether EPLC Initiated the Consultation

The consultations with ratepayers were initiated by EPLC through the Innovative Research Group. The Customer Satisfaction Survey in June 2023 was conducted via telephone survey and included interviewing 378 residential customers and 35 general service customers. The Ratepayer Survey in November 2023 was conducted via e-mail survey and including interviewing 1,874 residential customers and 21 small business customers.

Both INNOVATIVE reports are attached as Appendix C.

INNOVATIVE submitted the final report for the Customer Satisfaction Survey in July 2023. Overall, 79% of residential and GS<50 customers indicated they were satisfied with EPLC. Customer satisfaction is measured in terms of:

- Overall Satisfaction
- Power Quality & Reliability
- Reasonable Price
- Value for Money
- Communications

- Customer Service Experience

The Ratepayer Survey final report was completed in December 2023. EPLC successfully gathered 1,874 survey submissions from residential customers and 21 survey submissions from small business customers. The survey was distributed to 12,967 of EPLC's customers, resulting in a 15.1% response rate for residential customers and a 3.8% response rate for small business customers. Out of the various priority options provided, the top five priorities selected by the customers included:

1. Ensuring reliable electrical service (in the top three priorities for 69% of respondents)
2. Delivering reasonable electricity distribution prices (in the top three priorities for 65% of respondents)
3. Replacing aging infrastructure that is beyond its useful life (in the top three priorities for 41% of respondents)
4. Investing in infrastructure and/or technology to better help withstand the impacts of adverse weather (in the top three priorities for 40% of respondents)
5. Helping customers reduce and better manage their electricity consumption (in the top three priorities for 24% of respondents)

Receiving customer feedback helps reinforce EPLC's business and distribution system planning priorities.

5.2.3.2 Subdivision Developers

Purpose of the Consultations

EPLC has frequent, ad-hoc consultations with subdivision developers to understand planned construction activities and subdivision growth. This in turn, affects EPLC's project planning and operations. EPLC has initial communications with developers via email and/or virtual meetings (Microsoft Teams). After initial consultation and all relevant information is collected, EPLC will set a pre-construction meeting on-site. Progress meetings and communications during the project are done by phone, email, virtual meetings, and site visits, where necessary.

Whether EPLC Initiated the Consultation

The meetings are initiated by sub-division developers and subsequent meetings are initiated by EPLC.

Other Participants in the Consultation

The meetings are attended by developers, EPLC, and consultants.

Nature and Prospective Timing of the Final Deliverables

Meeting minutes from these consultations typically summarize the deliverables and timeline commitments agreed to by each party in the meeting. Deliverables include updated construction schedules, updated project cost estimates, an updated list of agreements pertaining to subdivision construction, and any requisite studies (if applicable).

Effects on the DSP

Subdivision developer consultations are critical to allocating budget and resources for system access investments.

5.2.3.3 Municipalities

Purpose of the Consultations

Consultations with municipalities, who are also EPLC's shareholders, are critical components of EPLC's project planning and daily operations. EPLC is engaged in weekly Adjustment Committee meetings on property zoning variances. Weekly Development Support Committee meetings provide details regarding planned and ongoing construction activities for private businesses and residences. Quarterly utility meetings allow the municipalities and various utility participants to coordinate their planned and ongoing construction activities. In addition, meetings related to alley closing or land transfers take place as needed. Planning Act meetings take place as applicable, and meetings for specific projects take place as needed.

EPLC also participates in meetings with the County of Essex and the Ontario Ministry of Transportation ("MTO") as required to obtain information pertaining to the capital work planned.

Whether EPLC Initiated the Consultation

The meetings are initiated by EPLC or the municipalities. County and MTO meetings are typically initiated by the County and MTO, respectively.

Other Participants in the Consultation

The meetings are attended by representatives of different municipal divisions (e.g. municipal projects, water) and other utilities (e.g. Bell, Cogeco, HONI, Union Gas, MNSi).

Nature and Prospective Timing of the Final Deliverables

The meeting minutes of items discussed are the main deliverables for most municipal consultations. Following the utility meetings, EPLC receives an updated project list from the various municipal divisions and from the other utility participants via email or web portal. EPLC provides its own list of capital projects and pertinent operations activities (e.g. tree trimming) to participants in the meetings.

Effects on the DSP

Municipal consultations are critical to allocating budget and resources for system access investments including residential expansions, individual secondary services, new commercial/industrial services, and third-party infrastructure development requests. Planned projects in the near-term are used to forecast the capital requirements of the five-year DSP.

5.2.3.4 Transmitter

Purpose of the Consultations

EPLC often communicates and meets with Hydro One Networks Inc ("HONI") with the overarching objective of providing reliable and cost-effective service to EPLC's customers. In addition to the IESO's Regional Planning Process, HONI and EPLC hold quarterly planning meetings to discuss operating issues, billing issues, customer complaints, work coordination, joint use of poles, and generation connection. Other communications and meetings take place to discuss specific projects, as well as projects to separate shared assets by LDC, asset, customer, etc.

Whether EPLC Initiated the Consultation

Consultations may be initiated by either EPLC or HONI.

Other Participants in the Consultation

There are no other participants in these consultations. The only participants include EPLC and HONI.

Nature and Prospective Timing of the Final Deliverables

Meeting minutes from these consultations typically summarize the deliverables and timeline commitments agreed to by each party in the meeting. Deliverables include updated construction schedules, updated project cost estimates, an updated list of generation projects, agreements pertaining to asset transfers, and any requisite studies.

Effect on the DSP

A significant portion of the system service investments over the five-year planning period of the DSP are a result of coordinated planning activities with HONI. EPLC plans to purchase assets from HONI in two areas. This includes two feeder's sections in Amherstburg and two feeder's sections in Leamington.

5.2.3.5 IESO

Purpose of the Consultations

Outside of the Regional Planning Process, EPLC consults with the IESO to discuss the connection of new generation and energy storage projects to EPLC's distribution system, as well as frequent meetings to discuss EPLC's Grid Innovation Project (DSO pilot) funded through the IESO.

Whether EPL Initiated the Consultation

Consultations may be initiated by either EPLC or the IESO.

Other Participants in the Consultation

The only participants in the consultation are EPLC and the IESO.

Nature and Prospective Timing of the Final Deliverables

The IESO provides updates to generator applications within EPLC's service area.

EPLC uses the IESO's Beacon portal to track projects and final deliverables on IESO-contracted generators.

EPLC meets with the IESO on its Grid Innovation Fund Project with ad-hoc meetings and meetings when milestones are achieved.

Specifically for this DSP, EPLC submitted its REG Investments Plan to the IESO and the IESO provided its Comment Letter in response. For more information, see Appendix E.

Effect on the DSP

REG connections fall under the system service category and have been coordinated with the IESO. EPLC's REG investment plan is described in section 5.3.4.

5.2.3.6 Regional Planning Process

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

EPLC is part of the Windsor-Essex region in the most southerly part of Ontario, which includes the City of Windsor, the Municipality of Leamington, the Towns of Amherstburg, Essex, Kingsville, Lakeshore, LaSalle, Tecumseh, and the Township of Pelee, as well as the western portion of the Municipality of Chatham-Kent. Figure 5.2-4 illustrates the region of Windsor-Essex and Kingsville-Leamington area.

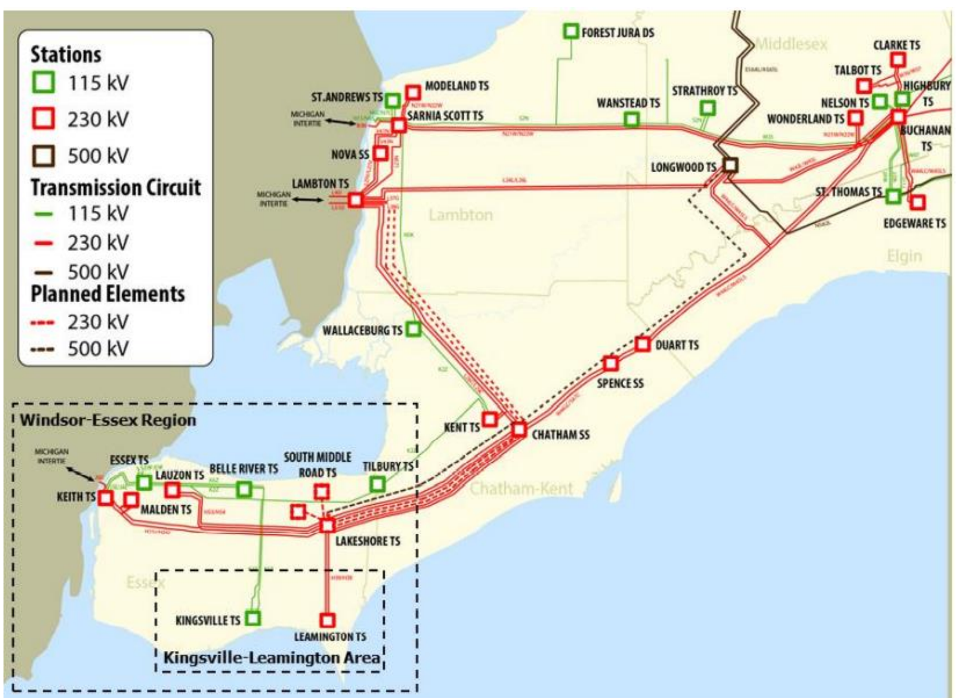

Figure 5.2-4: Map of the Windsor-Essex Region and Kingsville-Leamington Area

Following the 2019 RPP, stations capacity, supply capacity, load security, and restoration needs were identified within the Windsor-Essex region. These needs are attributed to fast-growing electricity demand within the indoor agricultural industry due to expansion of greenhouses and increased use of indoor grow lights to support year-round production.

Local reliability issues have specifically been identified in the Kingsville-Leamington area within EPLC's service territory. Capacity needs in this area are attributed to the limited time rating of the stations in the area, and voltage change violations existing at Kingsville TS. The total capacity need for the Kingsville-Leamington area is forecasted to be 440 MW, which includes 410MW of expected growth from new greenhouse customers, and 30MW is already overloaded at Kingsville TS. There have also been load restoration needs identified for the Leamington tap lines in order to meet the load restoration planning requirements (ORTAC Section 7.2).

Within the Addendum Report to the 2019 RPP, various recommendations were identified to address the capacity and load restoration needs in the area. Firstly, it has been recommended that two new Dual Element Spot Network (DESN) stations are to be built and supplied from 230 kV double-circuit lines from the Lakeshore Switching Station (SS) to address capacity needs. The existing Kingsville TS will be subsequently offloaded to its 95 MW capacity. It is noted that there will still be 20 MW of capacity needs in the area following this recommendation. Economic development and load growth in the area will continue to be monitored to identify any need or requirement for additional transmission investments. There was also recommendation that a new 230 kV double-circuit line be installed between Leamington TS and the new DESN station to allow for approximately 290 MW of load restoration capability. Lastly, it was recommended that 60 MW of capacity be provided by distributed energy resources and/or distribution-level transfer capability. The recommendations of the working group, along with their proposed timeframes are provided in Table 5.2-2.

Table 5.2-2: Proposed Recommendations

Item Number	Working Group Recommendation	Lead Responsibility	Timeframe
1	Transfer load in excess of the station load meeting capability to the new DESNs once in-service	HONI	2026
2	Initiate engagement and approvals for two new 230 kV DESNs and double-circuit connection lines from Lakeshore SS	HONI	2022
3	Monitor load growth, regional and bulk transmission projects, DERs, and energy efficiency; continue gathering information on developments in the indoor agriculture industry and emerging technologies as required to inform the next planning cycle	IESO	Ongoing
4	Initiate engagement with customers to determine cost-justified measures (new 230 kV line, distributed energy resources, and/or distribution load transfer capability) that can mitigate this need	HONI	2022
5	Include the option for a new 230 kV line between Leamington TS and the new	HONI	2022

	DESNs in the Environmental Assessment for Item #2		

5.2.3.7 Telecommunication Entities

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

EPLC informs service providers of its upcoming plans to identify and promote any opportunities for coordination between parties. In the case of planned upgrades or construction projects, EPLC organizes regular status meetings with the telecommunications companies to review project status, make-ready work, future work and align project timelines to ensure efficient project completion and reduced customer complaints for each party. Table 5.2-3 summarizes the communication between EPLC and their Joint Use partners to determine if there are upgrades or construction projects planned during the forecast period.

Table 5.2-3: Summary of Consultations

Date of Consultation	Consultation Overview	Participants
January 6, 2024	New Construction or Upgrades	Hydro One
January 6, 2024	New Construction or Upgrades	Enwin Utilities
January 6, 2024	New Construction or Upgrades	Cogeco
January 6, 2024	New Construction or Upgrades	Bell
January 6, 2024	New Construction or Upgrades	MNSi
January 6, 2024	New Construction or Upgrades	Telus
January 6, 2024	New Construction or Upgrades	Elringklinger

<u>Result of Consultations</u>

Two of the seven participants responded with no planned construction or upgrades scheduled within Essex Powerlines service area with no response back from the remaining five participants.

5.2.3.8 CDM Engagements

CDM activities are aimed at reducing electricity consumption to alleviate constraints and reduce peak demand, with the goal of managing system costs and increasing reliability for customers. Historically, CDM initiatives undertaken by EPLC have resulted in some reduction in peak demand, however, these reductions have not been enough to avoid infrastructure renewal investments and the need to find new approaches to addressing constraints.

For EPLC, CDM activities are a significant consideration in the Distributor's approach to the energy transition and the associated impacts of electrification, decarbonization mandates, and increasing constraints on the local distribution system. Following the Conservation and Demand Guidelines of Electricity Distributors, which states that "CDM activities may potentially include non-distributor owned, behind-the-meter solutions"[1], EPLC has undertaken a pilot project aimed at leveraging distributed energy resources to alleviate local constraints and improve local reliability.

EPLC was a successful applicant in response to the Independent Electricity System Operator (IESO)/Ontario Energy Board (OEB) Joint Targeted Call (JTC) for innovative projects focused on deriving value from distributed energy resources (DER). On March 7, 2022, EPLC was advised that its proposed project, "Essex Powerlines DSO Pilot Project" (PowerShare), was successful in qualifying for funding through the IESO's Grid Innovation Fund and support from the OEB Innovation Sandbox.

Further regulatory guidance was provided from the OEB to EPLC by way of letter dated May 31, 2022; more specifically, that the "activities proposed in connection with Pilot project can be considered distribution activities within the meaning of s. 71(1) of the *Ontario Energy Board Act*, 1998."[2]

The "Essex Powerlines DSO Pilot Project" is primarily aimed at alleviating known constraints on the distribution system as they currently exist. One example is within the Leamington service area, which has a high concentration of greenhouses that represent a significant load.

Included in the scope of the pilot project and associated funding are proposed payments to local DER owners for power procured to address local constraints. The pilot project estimated that EPLC would procure up to 5,000 MW of electricity over the course of two project phases spanning approximately 24 months. Alternatively, through project activities, and with a similar aim, EPLC may pay large users of power to curtail load to also alleviate constraints. Project funding is to be used to directly support these activities.

Greater details on the project activities, associated investments, and anticipated outcomes are included in section 5.4.1. Learnings from the project will further the understanding of local energy markets and their value in capital deferral, managing customer costs, and will continue to inform system planning.

5.2.3.9 Renewable Energy Generation (REG)

REG investments are prioritized alongside other capital projects using the processes, tools, and methods described in Section 5.3.1. EPLC has submitted its REG plan to the IESO.

5.2.3.9.1 IESO Comment Letter

EPLC has submitted its REG plan (Appendix D) to the IESO, and has a received a comment letter from the IESO (Appendix E).

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[1] Conservation and Demand Management Guidelines for Electricity Distributors, EB-2021-0106, p. 6

[2] OEB Letter May 31, 2022, attached herein as Appendix A.

5.2.4 PERFORMANCE MEASUREMENT FOR CONTINUOUS IMPROVEMENT

5.2.4.1 Distribution System Plan

EPLC continually measures and monitors its performance to ensure operational improvements are being made.. The performance measures employed by EPLC have evolved over the years and are currently fully aligned with OEB's "Scorecard – Performance Measures" for electricity distributors, as listed below:

- Service quality;
- Customer satisfaction;
- Safety;
- System reliability;
- Asset management;
- Cost control;
- Connection of renewable generation; and
- Financial ratios.

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

A summary of EPLC's historical performance as presented in the OEB Performance Scorecards is presented in Table 5.2-4**Error! Reference source not found.**. Each metric influences EPLC's DSP to achieve the best performance for its customers. The following sections summarize EPLC's operating performance during five years from 2018 to 2022.

5.2.4.1.1 Objectives for Continuous Improvement Set out in Last DSP Filing

This is not applicable.

5.2.4.1.2 Performance Scorecard

Table 5.2-4: DSP Performance Measures

Performance Outcome	Measure	Metric	2018	2019	2020	2021	2022	Target
Customer Focus	Service Quality	New Residential/Small Business Services Connected on Time	91.18%	94.78%	93.27%	90.84%	91.45%	90%
		Scheduled Appointments Met on Time	94.79%	93.15%	94.46%	93.15%	98.68%	90%
		Telephone Calls Answered on Time	87.67%	82.62%	65.17%	76.62%	80.94%	65%
	Customer Satisfaction	First Contact Resolution	98.52%	98.99%	99.15%	99.08%	99.60%	No target
		Billing Accuracy	98.26%	99.96%	99.92%	99.95%	99.95%	98%
		Customer Satisfaction Survey	83%	83%	86%	86%	86%	No target
Operational Effectiveness	Safety	Level of Public Awareness	83.00%	83.00%	83.00%	85.00%	85.00%	No target
		Level of Compliance with Ontario Regulation 22/04	C	C	C	C	C	C
		Number of General Public Incidents	0	0	0	0	0	0
		Rate per 10, 100, 1000 km of line	0.000	0.000	0.000	0.000	0.000	0.000
	System Reliability	Ave. Number of Hours that Power to a Customer is Interrupted	1.82	1.27	1.23	2.02	1.82	1.24
		Ave. Number of Times that Power to a Customer is Interrupted	1.29	0.84	0.95	0.89	0.84	0.74
	Asset Management	Distribution System Plan Implementation Progress	18.80%	37.50%	57.00%	76.13%	97.65%	No target
	Cost Control	Efficiency Assessment	2	2	2	2	1	No target
		Total Cost per Customer	$ 578	$ 580	$ 577	$ 564	$625	No target
		Total Cost per km of Line	$ 37,960	$ 10,907	$ 10,979	$ 10,789	$12,005	No target
Public Policy Responsiveness	Connection of Renewable Generation	Renewable Generation CIA Completed on Time	-	-	100.00%	-	-	No target
		New Micro-embedded Generation Facilities Connected on Time	100.00%	100.00%	-	-	100.00%	90%
Financial Performance	Financial Ratios	Liquidity: Current Ratio (Current Assets / Current Liabilities)	0.67	0.57	0.72	0.76	0.85	No target
		Leverage: Total Debt (short-term & long-term) to Equity Ratio	1.1	1.31	1.32	1.25	1.27	No target
		Regulatory ROE – Deemed (included in rates)	9.00%	9.00%	9.00%	9.00%	9.00%	No target
		Regulatory ROE – Achieved	8.11%	7.30%	6.14%	6.79%	6.09%	No target

5.2.4.2 Service Quality and Reliability

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

5.2.4.2.1 Service Quality Requirements

EPLC tracks and reports on Service Quality Requirements (SQR) in accordance with Chapter 7 of the OEB’s Distribution System Code (DSC). Table 5.2-5 presents EPLC’s SQR performance for the historical period. EPLC has met or exceeded the minimum standards in every year from 2018-2022, except for appointment scheduling in 2018 and 2022. The reason for these missed targets is due to decreased performance by contractors. Since 2010, EPLC has outsourced locate services, as this is the most cost-effective means of delivering this service. However, EPLC began to see a decrease in performance during the second quarter of 2018. EPLC contacted the contractor to address its concerns. As a result, an Action Plan was created, which included suggestions of hiring and training new resources to fulfill contractual requirements. EPLC closely monitored the compliance rate after the Action Plan was in affect and noted improvements during the last quarter of 2018. Appointment scheduling targets in 2022 were again due to challenges with third party contractors not meeting targets, specifically for locate requests. In addition, EPLC’s locate provider announced their plan to cease providing locating services in southwestern Ontario. As such, EPLC has made plans to change providers with the goal of performing locates as requested and required to meet the regulatory requirements.

Table 5.2-5: Historical Service Quality Metrics

Service Quality Metric	2018	2019	2020	2021	2022	Minimum Standards
Low Voltage Connections	91.18%	94.78%	93.27%	90.84%	91.45%	> 90%
High Voltage Connections	-	-	100.00%	-	-	> 90%
Telephone accessibility	87.67%	82.62%	65.17%	76.62%	80.94%	> 65%
Appointments met	94.79%	93.15%	94.46%	93.15%	98.68%	> 90%
Written response to enquiries	98.01%	97.64%	97.95%	97.86%	99.72%	> 80%
Emergency Urban Response	100.00%	100.00%	100.00%	100.00%	96.00%	> 80%
Emergency Rural Response	-	-	-	-	-	> 80%
Telephone call abandon rate	0.60%	0.94%	3.96%	0.75%	1.44%	< 10%
Appointment scheduling	75.79%	93.11%	98.37%	99.22%	85.87%	> 90%
Rescheduling a Missed Appointment	100.00%	100.00%	100.00%	100.00%	100.00%	> 100%
Reconnection Performance Standard	97.87%	97.46%	96.03%	97.96%	97.93%	> 85%
New Micro-embedded Generation Facilities Connected	100.00%	100.00%	-	-	100.00%	> 90%
Billing Accuracy	98.26%	99.96%	99.92%	99.95%	99.95%	> 98%

5.2.4.2.2 Reliability Requirements

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

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

Loss of Supply (LOS) outages are beyond EPLC's control; however, EPLC works closely with its supply transmitter (HONI) to reduce incidents of loss of supply. "Major Events" are defined by OEB as the events beyond the control of the distributor and are unforeseeable, unpredictable, unpreventable, or unavoidable. Such events disrupt normal business operation and occur so infrequently that it would be uneconomical to take them into account when designing and operating the distribution system. Such events cause exceptional and/or extensive damage to assets, they take significantly longer than usual to repair, and they affect a substantial number of customers. Major Event Days (MED) are calculated using the IEEE Std 1366-2012 methodology.

EPLC's system reliability targets are to operate its system better than the previous five-year historical average measured in SAIFI, SAIDI, and CAIDI.

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

Metric	2018	2019	2020	2021	2022	Average
SAIDI	8.11	3.13	2.42	4.71	4.690	4.61
SAIFI	5.76	2.34	1.68	2.08	2.800	2.93
CAIDI	1.41	1.34	1.44	2.26	1.675	1.63

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

Metric	2018	2019	2020	2021	2022	Average
	Loss of Supply Adjusted (including MEDs, Excluding LOS)					
SAIDI	1.82	1.27	1.23	2.02	1.82	1.63
SAIFI	1.29	0.84	0.95	0.89	0.84	0.96
CAIDI	1.41	1.51	1.29	2.27	2.17	1.73
	Loss of Supply and Major Event Days Adjusted (excluding LOS and MEDs)					
SAIDI	1.82	1.27	1.23	2.02	1.82	1.63
SAIFI	1.29	0.84	0.95	0.89	0.84	0.96
CAIDI	1.41	1.51	1.29	2.27	2.17	1.73

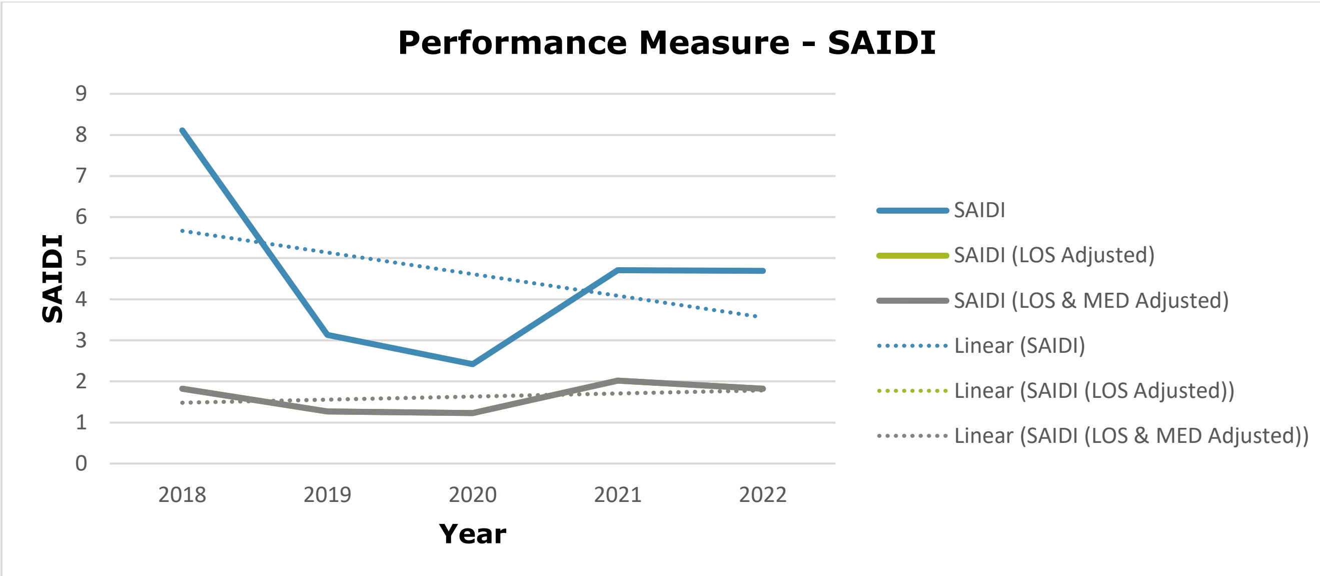


Figure 5.2-5: Performance Measure: SAIDI

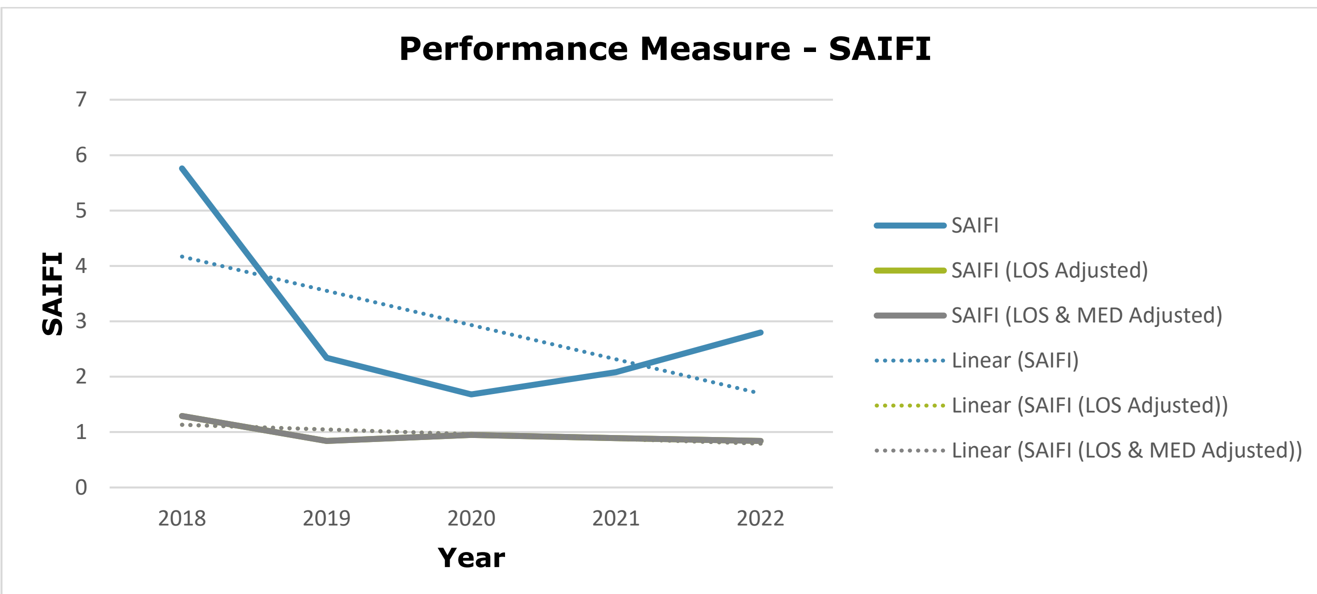


Figure 5.2-6: Performance Measure: SAIFI

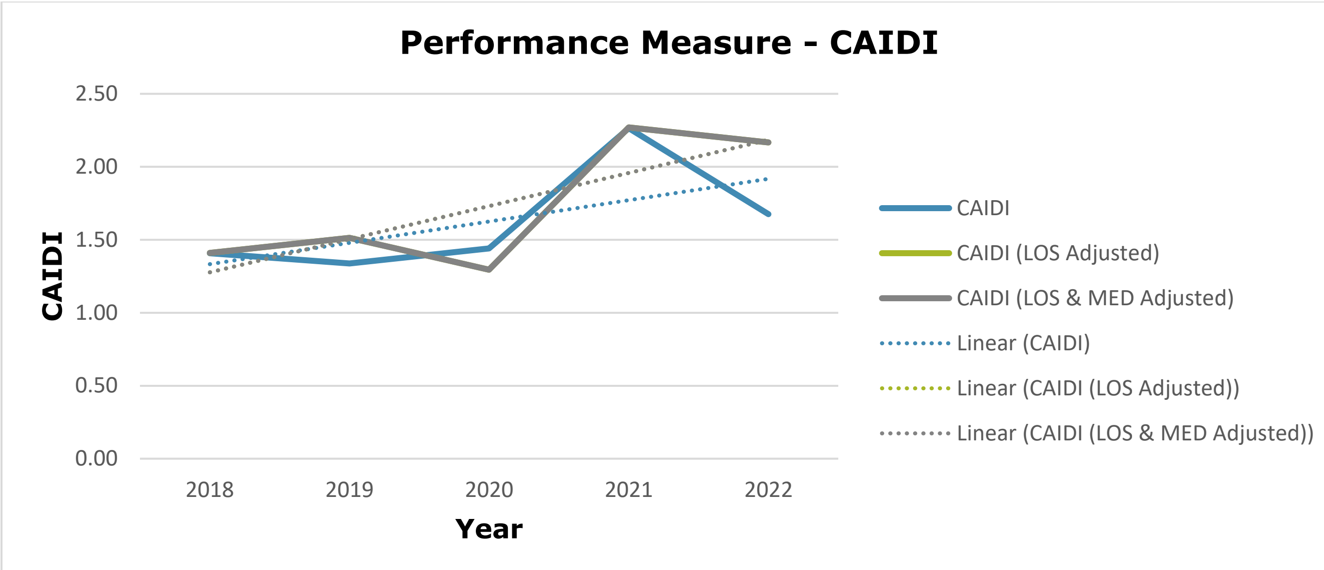


Figure 5.2-7: Performance Measure: CAIDI

EPLC's historical SAIDI and SAIFI performance has been higher than the distributor's target with the exception of the recorded SAIDI in 2020 of 1.23 which met the target of 1.24. The average SAIDI and SAIFI over the past five years are 1.63 and 0.96 while the targets are 1.24 and 0.74 respectively.

The largest contributor to EPLC's SAIDI metric is loss of supply outside of EPLC's service territories. In 2022, loss of supply accounted for 61.2% of EPLC's SAIDI metric. EPLC's SAIDI is also affected by factors such as scheduled outages, foreign interference, and adverse weather. A full breakdown of the factors that affect EPLC's SAIDI in 2022 are shown in Figure 5.2-8. EPLC's SAIFI metric is predominantly affected by scheduled outages, accounting for 48.9% (in 2022), as well as other factors such as foreign interference (animal, vehicle, dig-in) and defective equipment, shown in Figure 5.2-9.

EPLC uses several tools and processes to improve these metrics as part of its Best-In-Class Asset Investment Strategy including:

- Optimizing investments to minimize risk through risk assessments and ensuring alignment with strategic objectives.
- Maintaining Reliability Centered Maintenance ("RCM") statistics within acceptable severity.
- Conducting preventative maintenance and inspections on assets, and remediating findings.
- Utilizing a Global Information System ("GIS") for full customer connectivity and recording asset information.
- Utilizing SmartMAP software for alerts of out-of-range distribution system data (i.e. voltage, loading, fault current and outages) and engineering processes (i.e. modelling, design, and analysis).

In addition, the OEB issued a letter on November 30, 2021, launching its review of reliability and power quality in the Ontario electricity sector. The initial phase of its

Reliability and Power Quality Review ("RPQR") initiative focused on the enhancement and improvement of reliability data reporting by distributors, including the recording of sub-cause codes for interruptions. The RRR amendments to record sub-cause codes were to come into force on January 1, 2024, with reporting starting April 2025. As a result of the letter, EPLC took initiative to apply sub-cause codes in advance of the required start dates, and as such, has been tracking more detailed reliability statistics since early 2023. This enhanced tracking provides better data quality for EPLC to make informed investment decisions as it relates to grid enhancements for increased reliability.

Moreover, to combat loss of supply incidents and gain a better understanding of loss of supply causes, EPLC joined a pilot program with Hydro One Networks Inc on loss of supply reporting methods. As a result of the pilot, EPLC reports loss of supply incidences with justification to HONI and HONI then verifies the incident and updates the reason for the outage. This process gives a better understanding of why the outage occurred and allows EPLC to be more transparent with its customers.

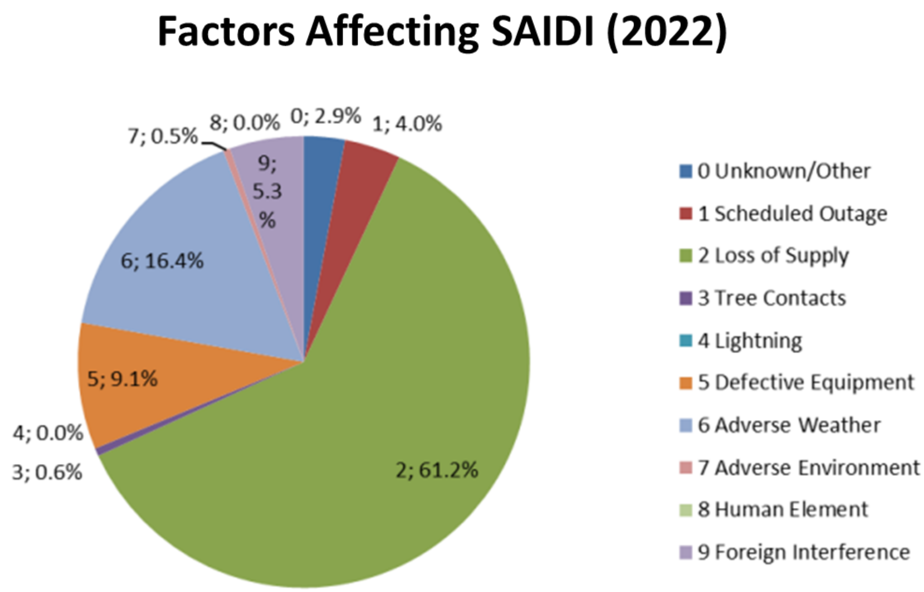


Figure 5.2-8: Contributing Factors to EPLC's SAIDI Metric, 2022

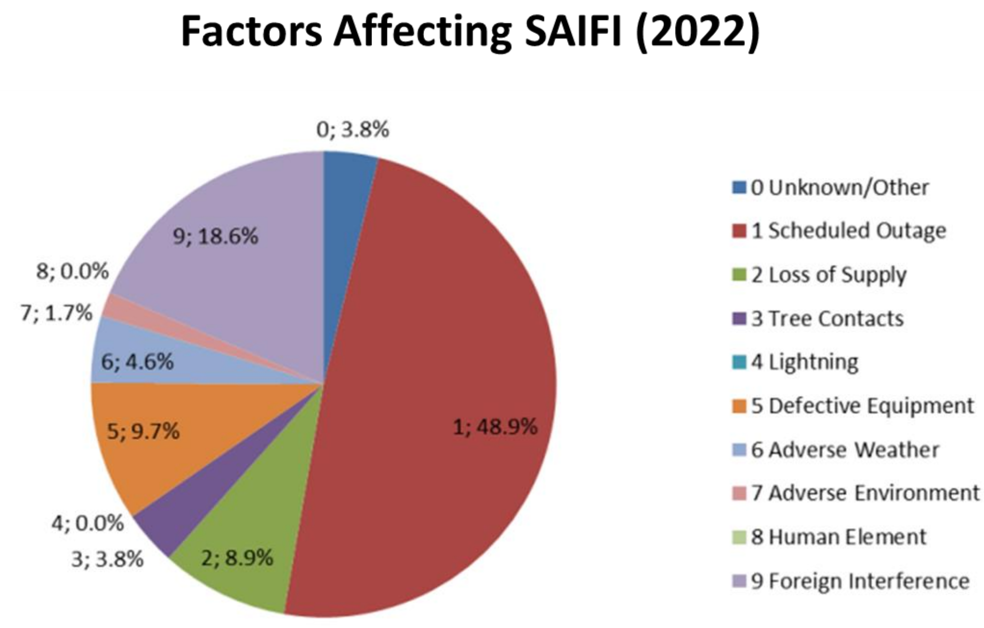


Figure 5.2-9: Contributing Factors to EPLC's SAIFI Metric, 2022

EPLC uses the SAIDI, SAIFI, and CAIDI reliability indexes to gauge the system reliability performance and maintain tight control over capital and maintenance spending. EPLC has planned investments in the System Renewal and System Service categories to replace end-of-life assets, which will help accommodate for forecasted load growth and maintain a healthy system reliability. These investments include:

- A Pole Replacement Program to address poles and associated assets that are at, or reaching, end-of-life in the next five years and are at risk of failure.
- OH & UG Infrastructure rebuilds to address OH and UG assets that are at, or reaching, end-of-life in the next five years.
- Self-Healing Grid investments to help better identify and isolate outages, as well as switch load to minimize the number of customers affected.

5.2.4.2.3 Outage Details for Years 2018-2022

A "Major Event" is an event that is beyond the control of Essex Powerlines. Because these events occur infrequently and unpredictably, these events are not considered when designing and operating the distribution system. EPLC has not reported any Major Event Days (MEDs) over the historical period.

<u>Outages Experienced by Cause Codes</u>

Table 5.2-8 presents a summary of total outages that have occurred within EPLC's service territory providing three different categorizations. The table values indicate a generally decreasing trend of outages within EPLC's service territory. A further breakdown by cause codes is provided in the following subsections.

Table 5.2-8: Number of Outages (2018-2022)

Categorization	2018	2019	2020	2021	2022
All interruptions	335	339	328	251	237
All interruptions excluding LOS	284	313	313	234	216
All interruption excluding MED and LOS	284	313	313	234	216

Outages Experienced

Table 5.2-9 presents the count of outages broken down by cause code for the historical period. The number of outages is an indication of outage frequency and impacts customers differently based on customer class. For example, residential customers may tolerate a larger number of outages with shorter duration while commercial and industrial customers may prefer fewer outages with longer duration thereby reducing the overall impact on production and business disruption. EPLC continues to assess and execute capital and O&M projects to manage the number of outages experienced.

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

Cause Code	2018	2019	2020	2021	2022	Total Outages	%
0-Unknown/Other	2	8	2	3	9	24	2%
1-Scheduled Outage	195	182	186	127	116	806	54%
2-Loss of Supply	51	26	15	17	21	130	9%
3-Tree Contacts	8	6	9	23	9	55	4%
4-Lightning	7	6	13	4	-	30	2%
5-Defective Equipment	22	39	23	25	23	132	9%
6-Adverse Weather	9	15	12	7	11	54	4%
7-Adverse Environment	1	-	5	2	4	12	1%
8-Human Element	-	1	-	-	-	1	0%
9-Foreign Interference	40	56	63	43	44	246	17%
Total	**335**	**339**	**328**	**251**	**237**	**1490**	**100%**

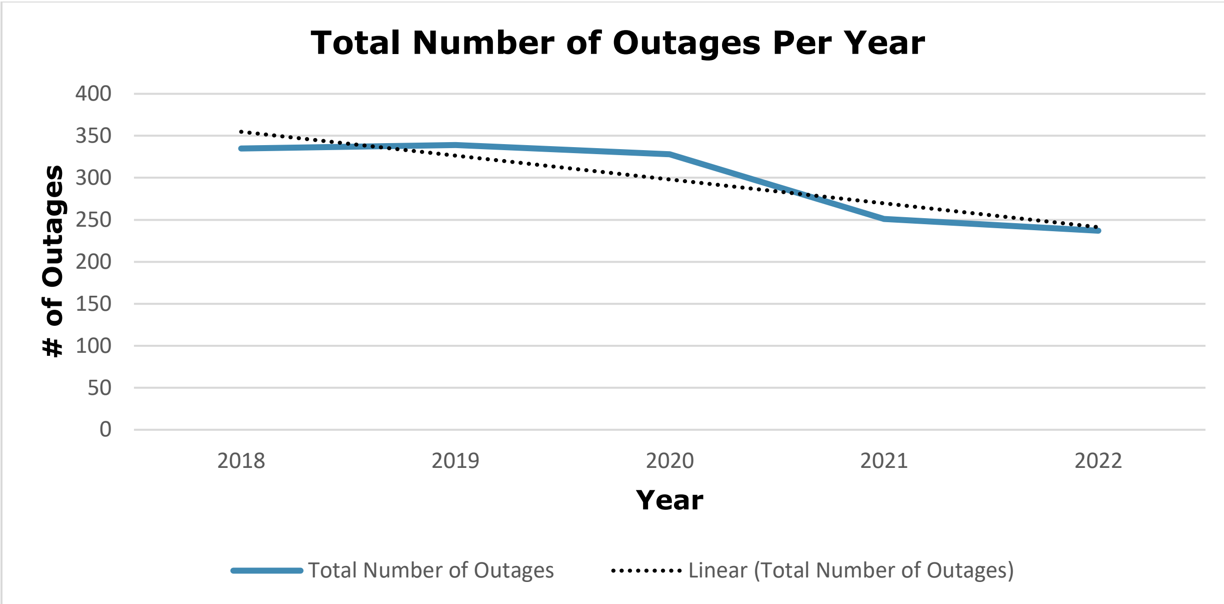


Figure 5.2-10: Total Number of Outages per Year

The total number of interruptions over the historical period is shown in Figure 5.2-10, varying from a low of 237 to a high of 339, with the overall trend decreasing in the period. This represents an average of 0.649 to 0.929 interruptions per day.

A summary of the causes of outages within EPLC's system is presented in Figure 5.2-11 along with the percentage of overall outage incidents attributable to each cause type.

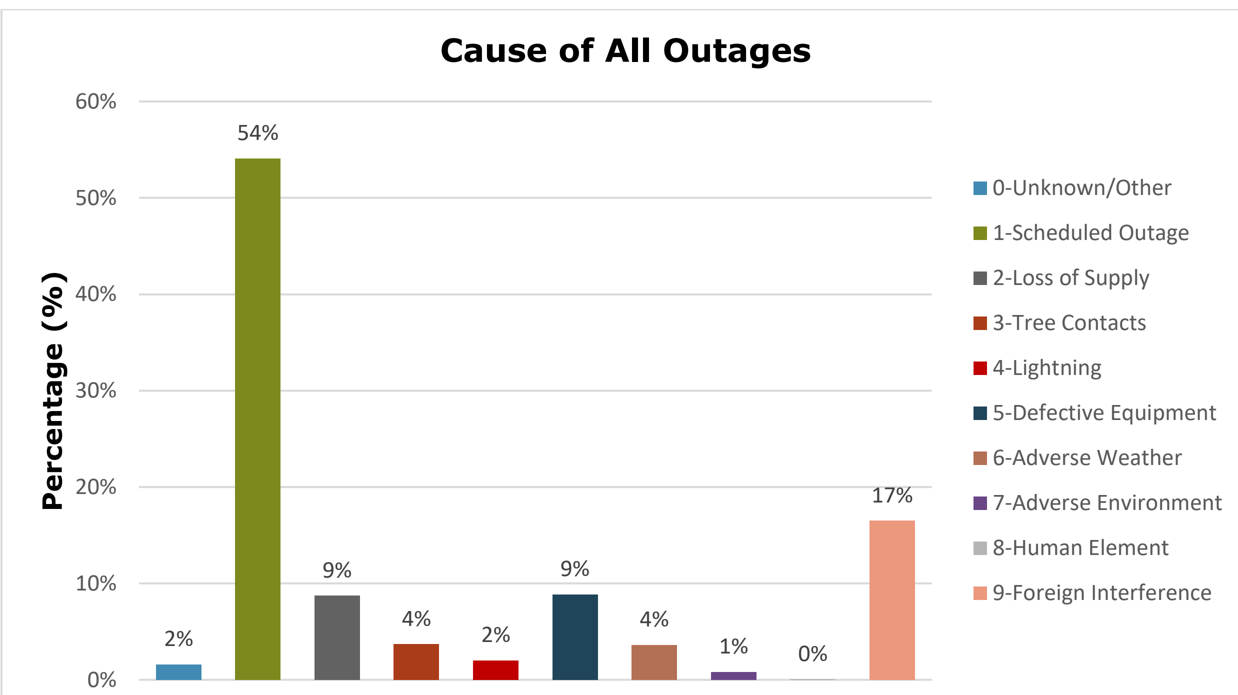


Figure 5.2-11: Percentage of Outages by Cause Code

Scheduled outages, foreign interference, loss of supply, and defective equipment have been identified to be the four most common causes for outages on EPLC's distribution system over the historical period. Together, these cases contributed 89% of the total number of outages from 2018 to 2022.

Scheduled outages are the top contributing cause to the total outages experienced by EPLC. Scheduled outages accounted for 54% of the total outages experienced by EPLC over the historical period. These outages are due to the disconnection of service for EPLC to complete capital investments or to perform maintenance activities on assets that require them to be disconnected to complete the work safely. EPLC aims to plan and execute capital work and maintenance appropriately in times that would affect minimal customers and with short durations.

At 17%, foreign interference is the second top contributing cause to the total outages experienced by EPLC. The main contributor to this cause is animal interference, with an average of 86.5% of foreign interference outages occurring due to animal contact in the last five years. This is primarily due to the geographic landscape of EPLC's service territory having a considerable amount of forestry and therefore, wildlife. Other contributing factors to the cause include dig-ins, vehicle collisions and/or foreign objects. Some of these contributing factors can be minimized through educating the public about calling before digging or installing animal guards in areas observed to have a high activity of animals, both of which EPLC continues to do. However, other factors such as vehicle collisions can happen at random and, depending on the extent and where the collision happens, may result in a significant impact.

Loss of supply and defective equipment make up 9% of total outages each (18% total). As noted in Section 5.2.3.4, EPLC meets regularly with HONI in part to address concerns of EPLC's customers, including loss of supply outages. EPLC has budgeted capital expenditures in the System Service category to purchase assets owned by HONI that already supply EPLC's customers. By effectively managing these assets, EPLC is proactively addressing the loss of supply issues to provide better system reliability for its customers. In terms of defective equipment, these failures result from equipment failures due to condition deterioration, aging effects or imminent failures detected from reoccurring maintenance programs. EPLC has planned investments to prioritize assets for replacement before experiencing a failure that may cause an outage. EPLC utilizes the ACA to assist in prioritizing investments in asset classes.

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

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

Table 5.2-10: Customers Interrupted Numbers by Cause Codes – Excluding MEDs

Cause Code	2018	2019	2020	2021	2022	Total CI	%
0-Unknown/Other	163	219	38	157	2,813	3,390	1%
1-Scheduled Outage	14,976	5,651	10,091	7,862	3,356	41,936	9%
2-Loss of Supply	134,448	45,323	22,200	36,691	61,201	299,863	67%
3-Tree Contacts	4,085	272	1,813	2502	653	9,325	2%
4-Lightning	831	352	4,782	313	-	6,278	1%
5-Defective Equipment	1,627	11,179	5,427	4044	5,334	27,611	6%
6-Adverse Weather	8,972	4,715	978	4617	5,854	25,136	6%
7-Adverse Environment	41	-	106	2263	3,060	5,470	1%
8-Human Element	-	11	-	-	-	11	0%
9-Foreign Interference	8,082	3,190	6,030	5933	5,226	28,461	6%
Total	**173,225**	**70,912**	**51,465**	**64,382**	**87,497**	**447,481**	**100%**

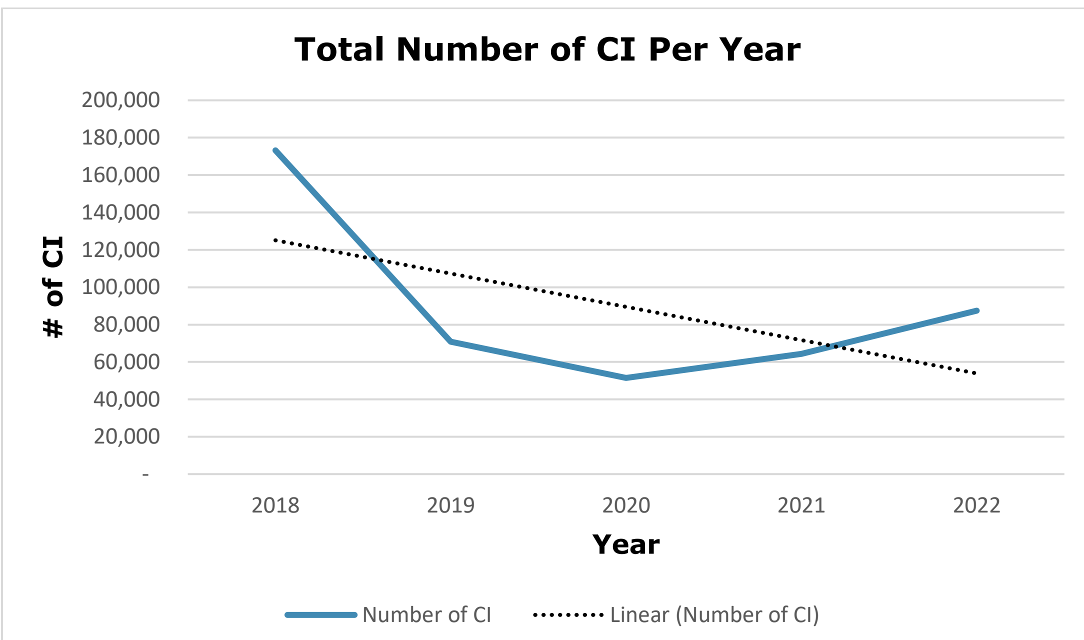


Figure 5.2-12: Total Number of Customers Interrupted by Year

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

Cause Code	2018	2019	2020	2021	2022	Total CHI	%
0-Unknown/Other	274	635	96	429	4,302	5,736	1%
1-Scheduled Outage	12,644	9,065	8,468	10,927	5,883	46,988	7%
2-Loss of Supply	188,983	56,318	36,689	83,375	89,677	455,042	65%
3-Tree Contacts	4,657	1,547	3,126	7,162	821	17,314	2%
4-Lightning	2,708	1,428	5,389	2,584	-	12,108	2%
5-Defective Equipment	4,719	13,588	5,573	8,309	13,267	45,455	6%
6-Adverse Weather	25,027	5,071	2,875	19,231	24,039	76,244	11%
7-Adverse Environment	113	-	72	1,667	721	2,573	0%
8-Human Element	-	20	-	-	-	20	0%
9-Foreign Interference	4,571	7,221	12,052	12,110	7,769	43,722	6%
Total	**243,697**	**94,893**	**74,339**	**145,793**	**146,480**	**705,201**	**100 %**

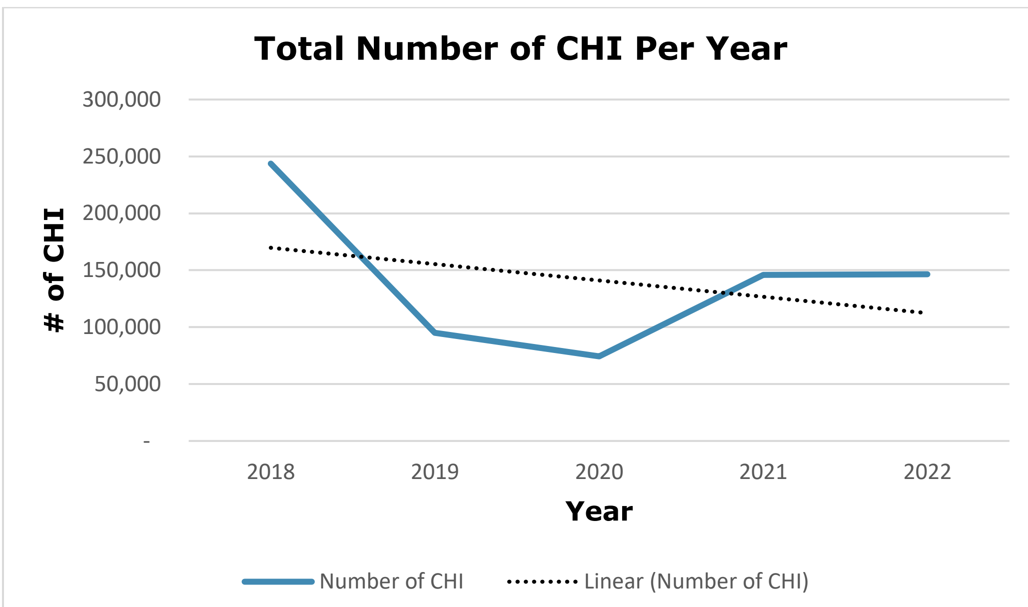


Figure 5.2-13: Total Number of Customer Hours Interrupted by Year

The overall trends over the historical period for the total number of CI and total number of CHI are decreasing (i.e. improving). The increase in 2021 of CI is largely attributed to Adverse Environment, which increased by 20.3 times between 2020 and 2021, as well as Adverse Weather which increased by 3.7 times between 2020 and 2021. Unknown/Other causes was also a major contributor to the increase between 2020 and 2021. The slight increase in CI in 2022 has mostly been driven by Unknown/Other causes. For CHI, the increase in 2021 is again, mostly driven by Adverse Environment which increased by 22.2

times between 2020 and 2021, followed by Adverse Weather which increased by 5.7 times between 2020 and 2021. A similar pattern has been observed in 2022.

When analyzing CI and CHI, Loss of Supply, Adverse Weather, and Scheduled Outages are among the top contributors.

- Adverse weather is beyond the control of EPLC. However, EPLC has, and will continue to design and invest in, storm hardening measures (i.e. physical improvements that can make utility infrastructure more resistant to weather).
- As previously noted, there are several ongoing and planned efforts to manage loss of supply and scheduled outage interruptions and continue to work towards reliability targets. These efforts include effective management of assets purchased from HONI to serve customers within the EPLC service area and mitigate loss of supply issues, as well as executing capital work and maintenance at times that would affect minimal customers to address the impacts of scheduled outages.

5.2.4.3 Distributor Specific Reliability Targets

Consumer Bill Impacts

Approximately 80% of a typical residential customer's bill is due to factors outside the control of the LDC (i.e., electricity, transmission, debt retirement, market charges, global adjustment, etc.). Notwithstanding that, surveys indicate that it is the overall cost of the bill, not the individual components, that are of concern to the customer. EPLC's target for this measure is for rate impacts in residential and general service classes to remain within OEB rate mitigation guidelines.

Power Quality

EPLC tracks power quality by monitoring the voltage at various customer meters. To monitor power quality over the forecast period, EPLC will continue to track the number of outstanding substantiated power quality concerns reported at year-end as a metric.

Asset Management

Asset performance is measured by the annual number of cable failures and annual number of switchgear failures.

5.3 Asset Management Process

The purpose of EPLC's asset management process is to develop projects for the future planning horizon using leading-edge Asset Investment Strategy ("AIS") tools. The Institute of Asset Management defines AIS as "the set of disciplines, methods, procedures, and tools to optimize the whole life business impact of costs, performance and risk exposures (associated with the availability, efficiency, quality, longevity and regulatory / safety / environmental compliance) of the company's physical assets."

The traditional approach to utility planning involves development of budgets using a "silo" approach where capital and O&M expenditures were planned for specific needs and then rolled up into an annual budget with no common linkage across the planning process. This approach is sub-optimal because little or no consideration is given to the trade-off opportunities, the value overlap, or the risk mitigation capability between capital investments and O&M programs. By determining its desired asset performance and risk tolerance, EPLC can develop an optimal resource investment plan, as detailed in this section.

5.3.1 Planning Process

5.3.1.1 Overview

A robust AIS relies on a clear understanding and the precise definitions of the organization's strategic business objectives. EPLC has established seven strategic business objectives that are applied to its asset management process. EPLC assesses the risk that an asset poses to its performance in these seven objectives using quantified data whenever possible. In cases where EPLC does not currently possess the capability to assess an asset's impact on a strategic business objective using quantitative data, then qualitative scores, which consider both the probability and consequence for each objective, are used. Table 5.3-1 lists the seven strategic business objectives and describes how EPLC's risk exposure is accounted for through its asset management process for each objective.

Table 5.3-1: EPLC's Asset Management Objectives and Related Corporate Goals

No.	Strategic Business Objective	Relation to Asset Management Processes
1	Public/Employee Safety	Qualitative scores (probability and consequence) for employee and public safety
2	Environmental	Qualitative scores (probability and consequence) for environmental implications
3	Regulatory	Qualitative scores (probability and consequence) for regulatory compliance
4	Service quality	Quantitative scores for SAIDI and SAIFI
5	Financial returns	Calculated Net Present Value ("NPV")
6	Legal	Qualitative scores (probability & consequence) for legal exposure
7	Company Image	Quantitative data for customer complaints

For the purpose of prioritizing investments, these seven business objectives are assigned relative weights, which are described in Figure 5.3-1.

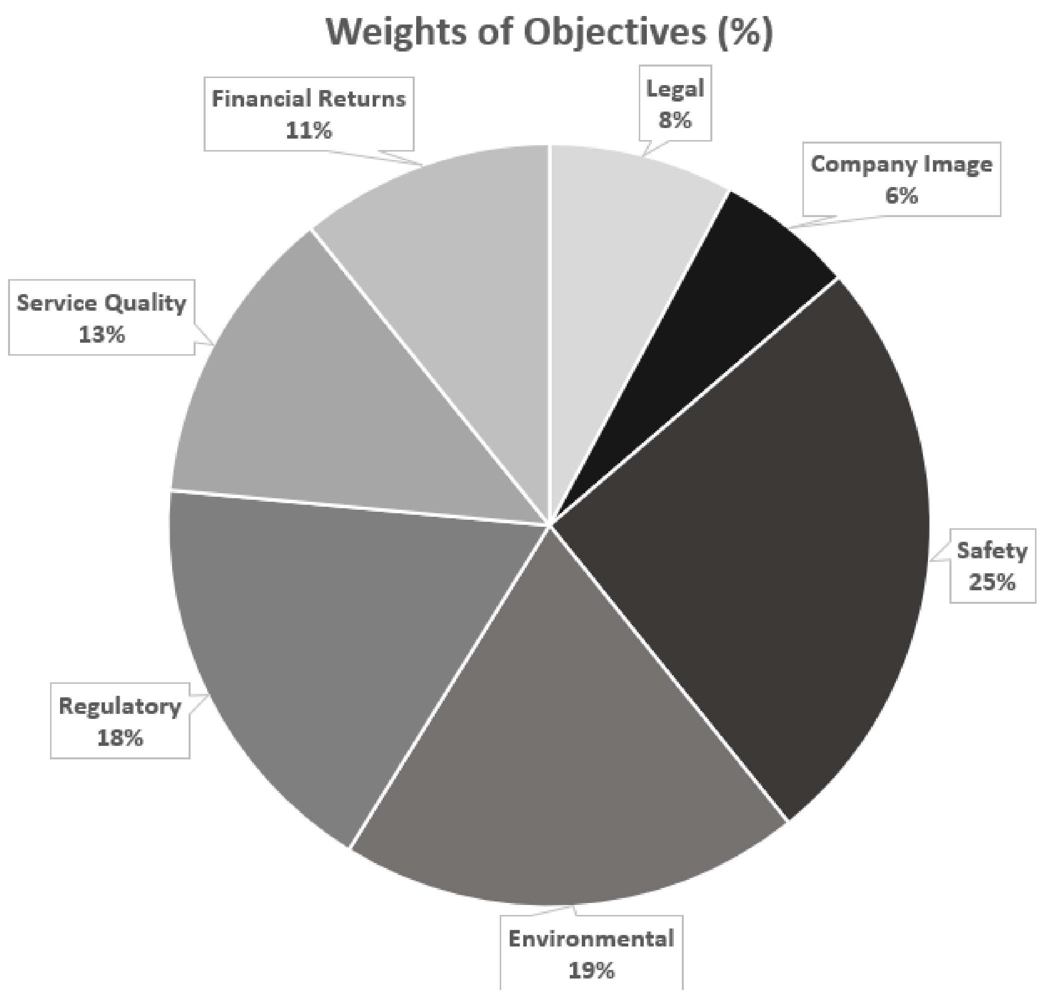


Figure 5.3-1: Numerical Weights Assigned to EPLC's Asset Management Objectives

Since qualitative scoring is applied to the safety, environmental, and regulatory business objectives, all of which have high numerical weights, there is a risk of a high sensitivity in the asset management process results. To mitigate this risk, EPLC applies a consistent methodology in its risk assessments, as described in Section 5.3.3.1 covering EPLC's asset lifecycle risk management policies and practices.

5.3.1.2 Important Changes to Asset Management Process since last DSP Filing

Since EPLC's previous Cost of Service Application in 2017, EPLC continues to invest in improved data quality and improved asset management analytic tools. Specifically, the partnership with Utilismart Corporation and EPL's Geo-Spatial Information System (GIS) continues to grow with the evolution of the SmartMAP software solution. SmartMAP provides information on asset condition and health on a daily basis.

In 2019, through the Grid Innovation Fund application, the SmartMAP tool gained another module that can detect the presence of EV's by identifying the charge characteristics associated with an individual residential meter. This development is key in supporting EPLC's understanding of where, how quickly, and what the impact of EV adoption has on the network.

In 2020, EPLC had also developed Work Center, a software suite of modular applications designed for electric utility companies. Modules of Work Center include requests (a work ticket system), job estimates (estimating and design), job lookup and job closeout (job costing information), scheduling, inventory management, and reports. This tool has been imperative for tracking and analyzing utility data, which is used in the asset management process. EPLC is continuing to develop new features of Work Center, with work planned in 2024 to include digital job packaging, among other relevant features.

5.3.1.3 Process

EPLC's AIS is a risk-disciplined, value-creation approach to strategic investment decisions that improves operational efficiency and system performance. In the past, utility companies built robust, redundant systems with underutilized capacity because regulatory environments encouraged such behaviour. By understanding the risk versus value trade-off associated with investing in asset replacement and system reticulation needs, the inherent value built into these systems can be reduced, released, or re-deployed for other capital resource requirements.

Consistent data reporting, good data repositories, and good analysis tools are necessary to develop an effective value-added and risk-disciplined approach to investment decisions. As such, EPLC uses an Asset Optimization Tool, which was developed by Texas Utilities and is currently owned by UMS Group Inc. The tool is used for making justified, risk-based decisions into asset investments on EPLC's system. The AIS is based on the best-in-class asset management framework described by the PAS-55 and ISO 55000 series asset management standards. The key characteristics of the AIS framework applied by the Asset Optimization Tool are shown in Figure 5.3-2.

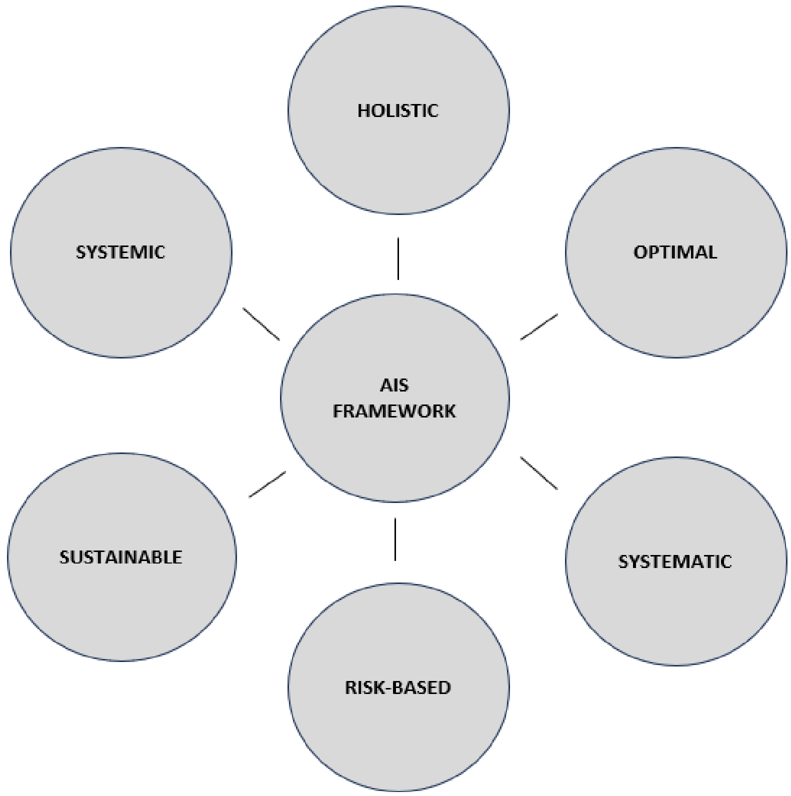


Figure 5.3-2: Key Characteristics of EPLC's AIS Framework

This AIS methodology employs a portfolio approach to investment decisions that embraces the performance linkage between capital and O&M expenditures. This approach helps facilitate development of an optimal Asset Investment Plan ("AIP") that includes a mixture of projects and programs that deliver the most value for the resource allocation. Spending is optimized based on the achievement of the seven strategic business objectives described in Section 5.3.1.1.

Quantification of the operational risk exposure mitigated by a project or program in the AIP is very important. Without this capability, management cannot make risk-informed financial decisions associated with a given resource allocation plan. Furthermore, better strategic and tactical decisions regarding asset replacement and maintenance investment decisions can only be made if the data is credible. Thus, the systems necessary for data reporting, storing, and analysis are crucial. As such, EPLC continues to use and develop SmartMAP: an integrated distribution monitoring and control system.

SmartMAP was developed based on EPLC's proven DESS and overlaid on a GIS with full connectivity and asset information. SmartMAP integrates voltage and load profiles, line temperature monitoring, ambient temperature, and line loss measurement. With this information, EPLC can accurately assess asset capacity utilization and identify constraints on the system. This streamlines EPLC's ability to meet customer/developer requests and to identify potential capacity upgrade projects. SmartMAP also includes fault current measurement and outage detection, which is used to identify damage to distribution assets and improve outage restoration time.

Figure 5.3-3: SmartMAP Integrates the Asset Register, DESS, and GIS

The software suite also includes HealthMAP, which integrates the asset health index with the GIS and provides alerts for out-of-range distribution system data. The health index is used in the asset condition assessment to determine the probability of an asset failure. The probability combined with the consequence of an asset failure constitutes a complete risk analysis. This includes quantification of SAIDI and SAIFI to determine the reliability risk as part of the consequence of failure analysis. The value creation is defined in terms of performance delivery and the risk mitigation capability is defined in terms of the Operational Beta. EPLC's customers directly benefit from the reduction in lifecycle costs of asset ownership, a reduction in the number of assets on the system, and inventory reduction.

Usage of these software tools allows EPLC to manage its AIP as a live model and make modifications to the plan as necessary. Resource planning is also incorporated in the tools to ensure adequate resource availability to conduct the plan. EPLC directs cyclical planned inspections and preventative maintenance activities to correct identified problems. Therefore, Reliability Centered Maintenance statistics are kept within acceptable severity/importance indices.

EPLC also relies on analysis of outage statistics for each service area and historical period data on customer interruptions caused by equipment failure to aid in its decision-making process. The complete AIS process is summarized in Figure 5.3-4. The integration of this consistent framework ensures that right-sized investments are made at the right time.

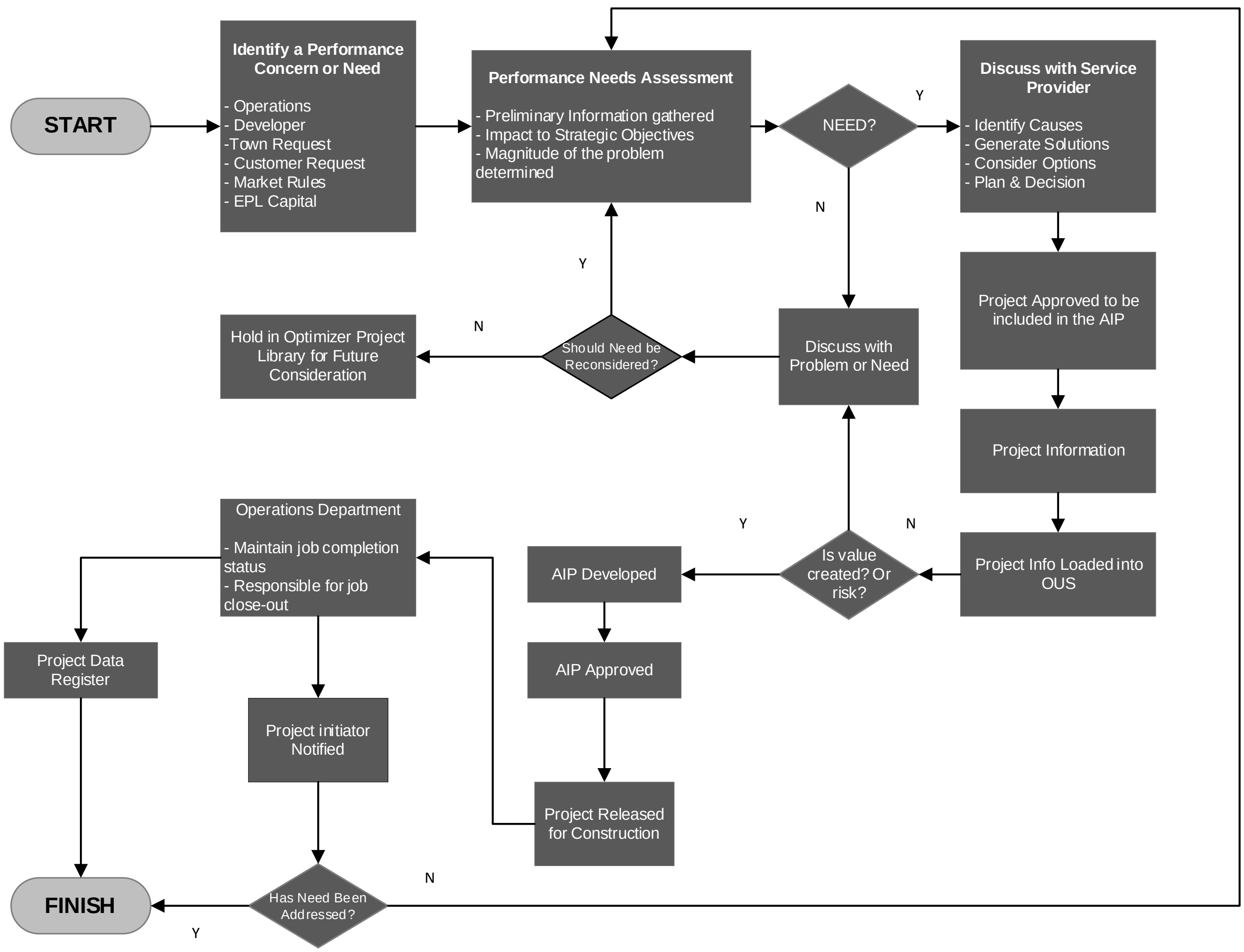


Figure 5.3-4: EPLC's Decision-Making Process Based on the AIS

5.3.1.4 Data

EPLC uses several datasets and inputs to assess the status of its assets and to assist in determining the capital and operational investments to be made. Key data inputs which are utilized as part of EPLC's AM process include asset information, outage data records, asset utilization and loading, customer engagement and survey results and information on innovative technologies being implemented in the industry. This information is stored within an asset register which is kept updated with current information. Amongst other systems, EPLC uses SmartMAP to track and analyze much of the data used to inform its planning processes. The section below summarizes the components of EPLC's asset register that is available and used for planning purposes.

System Performance Analysis

EPLC places a high level of importance on ensuring distribution system reliability meets the expectations of its customers. EPLC strives to continually improve its processes for collecting, measuring, analyzing, and using outage information within its AM process to effectively manage distribution system reliability in its service area. Outage causes are tracked and analyzed by outage cause codes within EPLC's SmartMAP system. This allows EPLC to identify trends in causes of outages and allows for this information to feed into its prioritization and evaluation process when developing its capital investment plans. The analysis is used to inform and support the development of O&M programs and capital expenditure plans for each year.

Inspection and Maintenance

EPLC regularly undertakes maintenance and inspection practices to maintain customer reliability and power requirements in the system. Inspection, maintenance, and operational data is collected, stored, and further used to support EPLC's operating and capital expenditure plans. Completion of the inspection and maintenance programs is not only a matter of compliance, but the results from the inspection and maintenance programs also allow for a continual update of the asset database. EPLC's inspection and maintenance programs are audited annually as required by Ontario Regulation 22/04. Further information on EPLC's maintenance and inspection practices can be found in Section 5.3.3.2. The outputs of these inspections and maintenance activities are a key input into the Asset Condition Assessment.

Asset Condition Assessment

An ACA annual update was completed in 2023, which uses conditions to identify those assets most likely to fail. The ACA involves the interpretation of condition and performance data of key assets to assess the overall condition of the asset and identify assets that have the highest likelihood of failure. The ACA is a key supporting tool for developing an optimized lifecycle plan for asset sustainability. The results of the ACA were incorporated into a formalized capital plan and have resulted in the revision of project prioritization within the service area for the forecast period. Further information on EPLC's ACA can be found in section 5.3.3.2 and Appendix B.

System Loading and Capacity

Load forecasting and capital growth planning continue to be the underlying basis for the near- and longer-term capital requirements for new or enhanced capacity. The loading and capacity information help to identify system needs and constraints. The information is collected on system peak loading at many points in the system and the data is analyzed to measure the risk of system overloading and to mitigate any concerns.

Customer Needs

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

Third-Party Infrastructure Requirements

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

Corporate Objectives

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

AM Objectives

EPLC's AM objectives, as outlined previously in section 5.3.1.1, are another key input into EPLC's AM process. These objectives help to define the content of the programs and the major projects in the capital expenditure plan to be able to sustain EPLC's electrical distribution system. The objectives guide EPLC to make effective capital investment decisions, which inherently make the best use of, and maximize the value of the assets to the company. The objectives identify an initial starting point and continue to be developed, enhanced, or adjusted as necessary to be aligned with the business environment that the company operates in and help to encourage the process of continuous improvement. The AM objectives have been integrated into EPLC's capital investment process to optimize and prioritize investments for several years including the test year. More details on EPLC's optimization and prioritization process can be found in section 5.3.3.3.

Technological Innovation

As part of its commitment to continuous improvement, EPLC monitors the state of technological advancements made within the utility sector and continues to invest in innovation and technology within its own distribution system. System automation, EV uptake, battery storage and other non-wires alternatives (NWAs) are considered as part of EPLC's planning process. Moreover, EPLC has focused on automation efforts through its self-healing grid project. This involves the installation of line monitors and automated switches to help modernize the grid. EPLC will continue to focus on installing smart devices within its distribution system to achieve grid automation and efficiencies. Additionally, over the 2024-2029 forecast period, EPLC plans to invest in technologies that will continue to improve utility data collection by focusing on real-time data capture and advanced analysis to drive real-time decisions. Where it is financially responsible to do so, these technologies may be incorporated into the renewal and upgrade projects to meet the current and future needs of customers, improve operational effectiveness, and support the integration of renewables and smart grid technologies. Theseinvestments will unlock new insights for customers and utilities, support DER integration, and participatory energy management, ensuring a future-ready network and DSO enablement. More details on EPLC's transition to a DSO can be found in section 5.3.5.1.

Cost Metrics

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

5.3.2 Overview of Assets Managed

5.3.2.1 Description of Service Area

5.3.2.1.1 Overview of Service Area

EPLC's service area is thirty-seven percent (37%) rural and sixty-three percent (63%) urban, consisting of four (4) non-contiguous service areas encompassing the Towns of Tecumseh, LaSalle, and Amherstburg, and the Municipality of Leamington.

EPLC does not own any substations and instead receives power from four (4) transformer stations (TS) owned by HONI. Each service area is embedded in a densely populated area of Ontario and the resultant distribution system is heavily tied to and dependent upon HONI-owned distribution assets. This dependence and influence results in a high percentage of outages originating on the HONI system that are beyond the control of EPLC. These outages cannot be managed with traditional distribution assets, such as manually operated switches or without advanced distribution system sensing devices.

Lengths of cables and conductors are measured in kilometres of circuit, where a 1-km run of three-phase cable is measured as 1 km rather than 3 km. EPLC owns 609 km of overhead lines and 1,004 km of underground cables.

5.3.2.1.2 Customers Served

EPLC services approximately 34,000 customers in its four (4) non-contiguous service areas but does not service all customers within the respective municipalities' borders except for the Town of LaSalle. In the other towns, the rural areas are serviced by HONI. EPLC's customer base is primarily residential and small commercial customers, with very few large industrial customers.

Most of EPLC's customers fall into one of the following classes: Residential, General Service (GS) less than 50 kW, and GS greater than 50 kW. EPLC also serves streetlight customers (municipalities), sentinel lights, and unmetered loads. The changing trends in EPLC's customer base for the years 2018 to 2022 of the historical period are shown in Table 5.3-2: Changing Trends in Customer Base. The total number of customers increased by an average rate of 1% per annum over this period.

Table 5.3-2: Changing Trends in Customer Base

Annual Year	Residential	General Service <50 kW	General Service ≥50kW	Total
2022	28,847	2,064	224	31,135
2021	28,637	2,065	202	30,904
2020	28,376	2,029	256	30,661
2019	28,134	1,997	262	30,393
2018	27,756	1,994	262	30,012

5.3.2.1.3 System Demand & Efficiency

Table 5.3-3: Peak System Demand Statistics

Annual Year	Winter Peak (kW)	Summer Peak (kW)	Average Peak (kW)
2022	80,413	122,714	85,600
2021	71,939	123,024	87,623
2020	75,038	126,420	85,747
2019	74,088	120,116	85,194
2018	74,064	126,059	89,194

Table 5.3-4: Efficiency of kWh Purchased by EPLC

Annual Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2022	555,804,644	561,682,478	1.05%
2021	549,391,694	561,179,041	2.10%
2020	536,185,894	546,609,085	1.91%
2019	538,071,920	554,349,941	2.94%
2018	545,925,556	558,276,019	2.21%

5.3.2.1.4 Summary of System Configuration

EPLC does not own any transformer stations and instead receives power directly from HONI feeders demarcated with primary metering units. Figure 5.3-5, Figure 5.3-6, Figure 5.3-7, and Figure 5.3-8 show an overview of feeder coverage in the Towns of LaSalle, Amherstburg, Tecumseh, and Leamington.

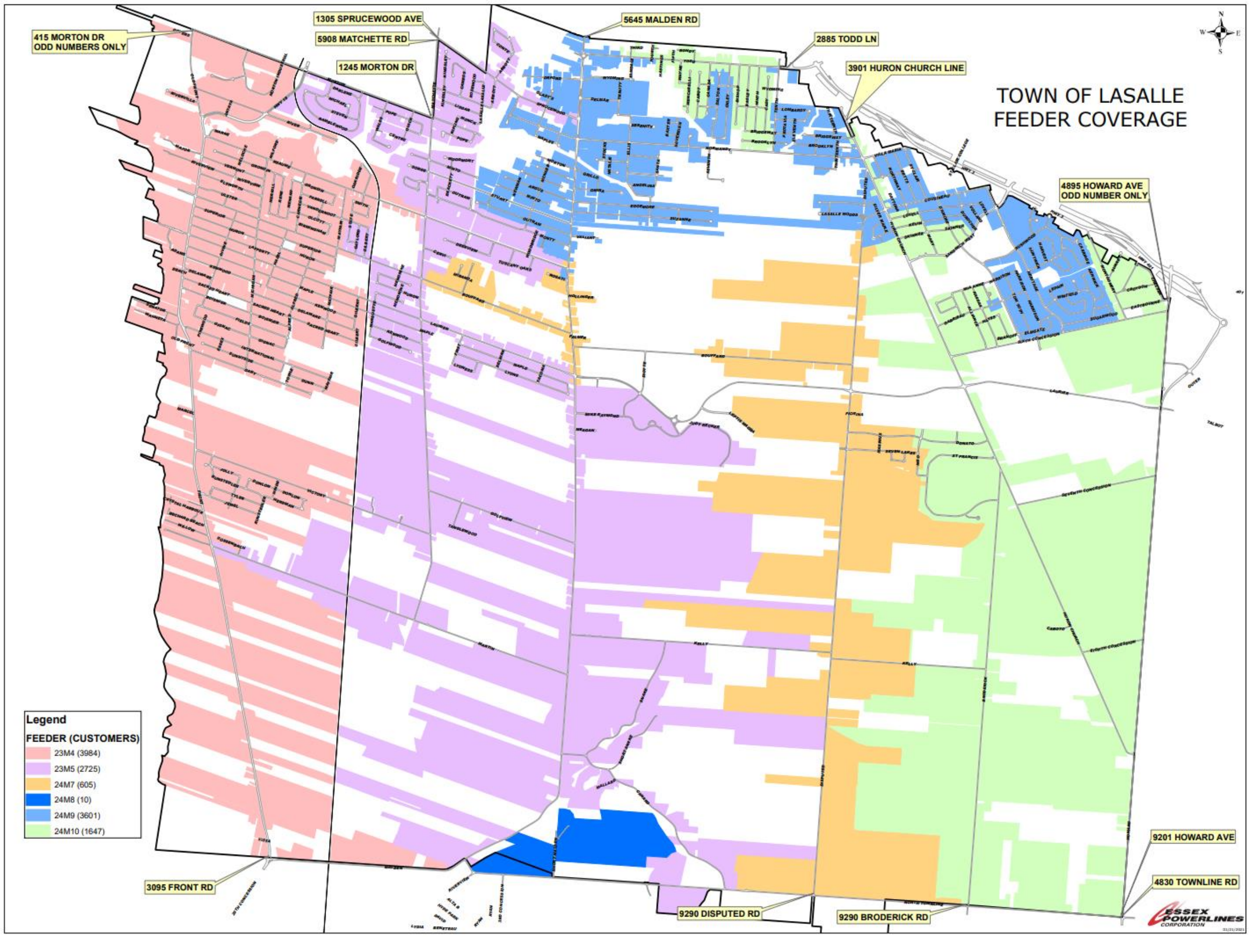


Figure 5.3-5: EPLC's Distribution System in LaSalle

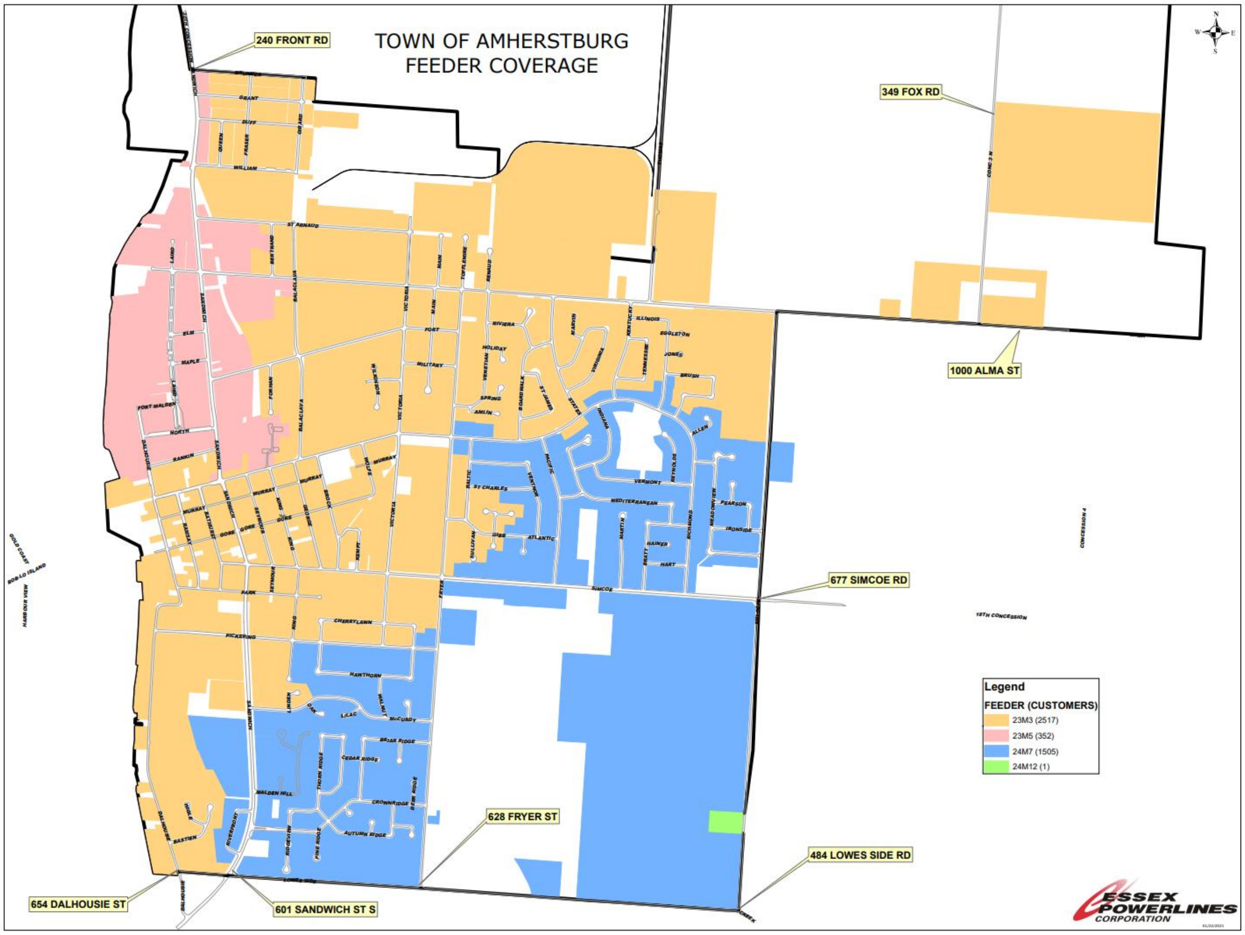


Figure 5.3-6: EPLC's Distribution System in Amherstburg

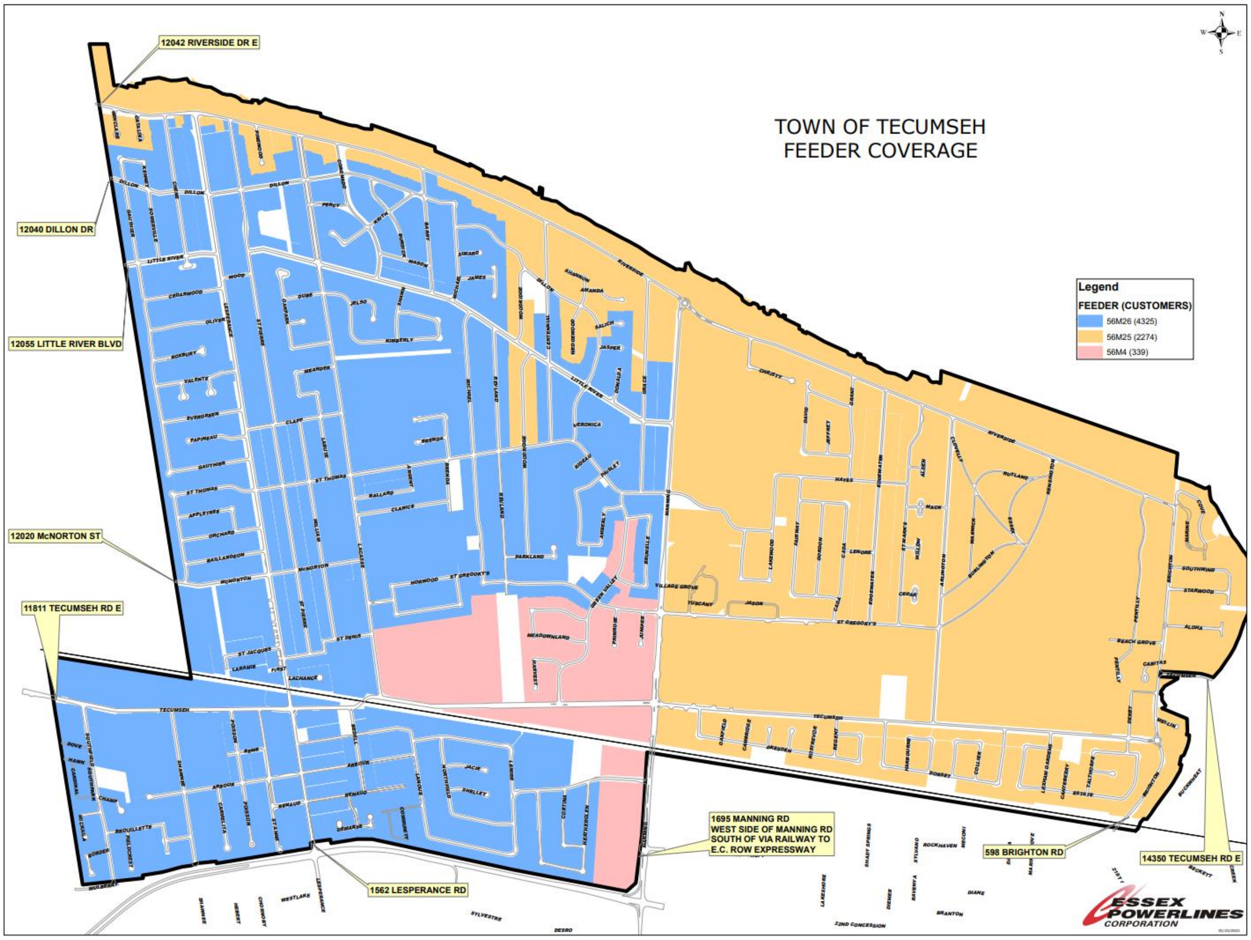


Figure 5.3-7: EPLC's Distribution System in Tecumseh

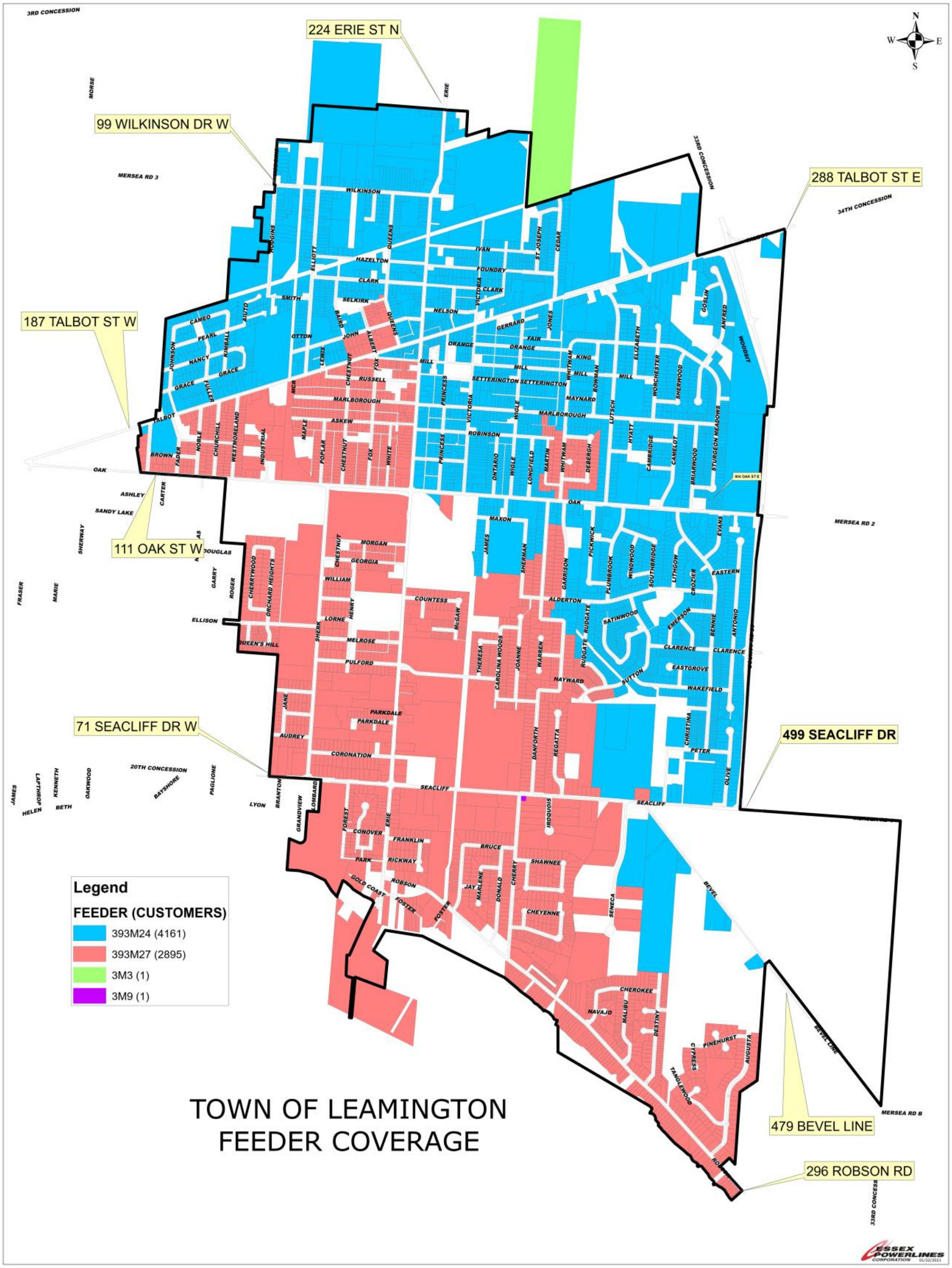


Figure 5.3-8: EPLC's Distribution System in Leamington

EPLC operates its distribution system at a single voltage: three phase lines are 27.6/16 kV and single-phase lines are 16 kV. Table 5.35Table 5.3-5 summarizes the system configuration.

Table 5.3-5: System Configuration

Conductor Type	Three Phase (km)	Single Phase (km)	Total (km)
Overhead	109.7	70.7	180.4
Underground	38.2	240.9	270.9

5.3.2.1.5 Climate

Situated in some of the most southern parts of Ontario, EPLC's service areas are subject to periodic heavy snowfalls, ice accumulation, and strong winds typical of the region. In the past few years, climate change issues have become a greater priority for the Windsor-Essex region. For instance, in 2019, the Windsor-Essex Environment Committee approved recommendations to declare a climate emergency in the area. Since then, the City of Windsor, the County of Essex, the Town of Amherstburg, the Town of Tecumseh and the Town of Essex have joined over 510 Canadian municipalities in declaring a climate emergency. In the past 5 years, Windsor-Essex has experienced tornadoes, floods, new temperature records, and record rainfalls, among other adverse weather events. With an increase in adverse weather, EPLC must be prudent in making asset investment decisions that bolster its distribution system and allow for grid hardening and increased reliability.

5.3.2.1.6 Economic Growth

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. This has added additional load as well as spin-off customers within EPLC's service territory. Electricity demand in Windsor-Essex and Chatham-Kent are forecast to grow from 500MW of peak demand today to about 2,100MW in 2035, almost the equivalent of adding a city the size of Ottawa to the grid.

Between 2024 and 2025, EPLC expects to add 18MW of night load and about 3 to 4 MW of baseload due to increased production of greenhouses and manufacturing within Leamington and Amherstburg service area.

It is evident that 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. To keep up with demand and continue to spur economic growth, EPLC must be prepared by investing in its distribution system.

5.3.2.2 Asset Information

5.3.2.2.1 Asset Capacity & Utilization

System utilization is assessed based on the peak load of each feeder relative to their respective ratings. Feeders are typically rated at the calculated ampacity. EPLC does not own any substations and therefore no Station Capacity is outlined.

Feeder Capacity

Table 5.3-6: Feeder Capacity and Utilization

Feeder	Planning Capacity (Amps)	2023 Typical Peak Load (Amps)	2023 % Utilization
23M3	627	232	37
23M4	627	345	55
23M5	627	356	57
24M7	627	269	43
24M9	627	319	51
24M10	627	292	47
56M25	627	180	29
56M26	627	347	55
56M4	627	386	62
393M24	627	325	52
393M27	627	344	55

Most of the feeders supplying EPLC are moderately loaded with enough capacity to address emergency and capacity demands with little room for more load.

5.3.2.2.2 Asset Condition & Demographics

An Asset Condition Assessment (ACA) was completed to assess the health of EPLC's assets. The complete ACA report is attached as Appendix B. EPL's ACA is based on data compiled up to October 2023 and covers the following classes of fixed assets owned:

- Wood poles
- Concrete poles
- Dip poles (primary risers)
- Pad-mounted transformers
- Pole-mounted transformers
- Load-break switches
- Switchgear units
- Switching cubicles
- Primary Overhead ("OH") conductors
- Primary Underground ("UG") cables

Table 5.3-6 summarizes the assessment criteria and Typical Useful Life ("**TUL**") for each asset class. The condition was determined for all asset classes except primary underground cables, for which only age demographics are known.

Table 5.3-7: Asset count, assessment criteria, and TUL for each asset class

Asset Class	Count	Assessment Criteria	TUL
Wood Poles	6,037	Resistograph test results, visual inspection results, service age	45
Concrete Poles	158	Visual inspection results, service age	60
Dip Poles (Primary Risers)	541	Visual inspection results, service age	45
Pad-Mounted Transformers	1,872	Visual inspection results, service age, IR results	40
Pole-Mounted Transformers	983	Visual inspection results, service age, IR results	40
Load-Break Switches	66	Visual inspection results, IR results	45
Switchgear	67	Visual inspection results, service age	30
Switching Cubicles	45	Visual inspection results, service age	30
Primary OH Conductors	180.4 km	Service age	60
Direct-buried Primary UG Cables	26.3 km	Service age	30
Primary UG Cables in Conduit	252.8 km	Service age	40

The assets have been assessed to be in one of five (5) conditions: Very Good, Good, Fair, Poor, or Very Poor. The results of the ACA are summarized in Figure 5.3-9 to Figure 5.3-11. Figure 5.3-9 shows that the majority of EPLC's assets are in Very Good condition. Figure 5.3-10**Error! Reference source not found.** and Figure 5.3-11 present the service age of EPLC's primary OH conductors and UG cables by TUL. TUL results for OH conductors show that 17.9 km are not near TUL. The majority of primary OH conductors are of unknown service age which adds uncertainty to the results. The results for primary UG cables show that 158.4 km are not near TUL, 71.6 km are approaching TUL, and 15.0 km are past TUL.

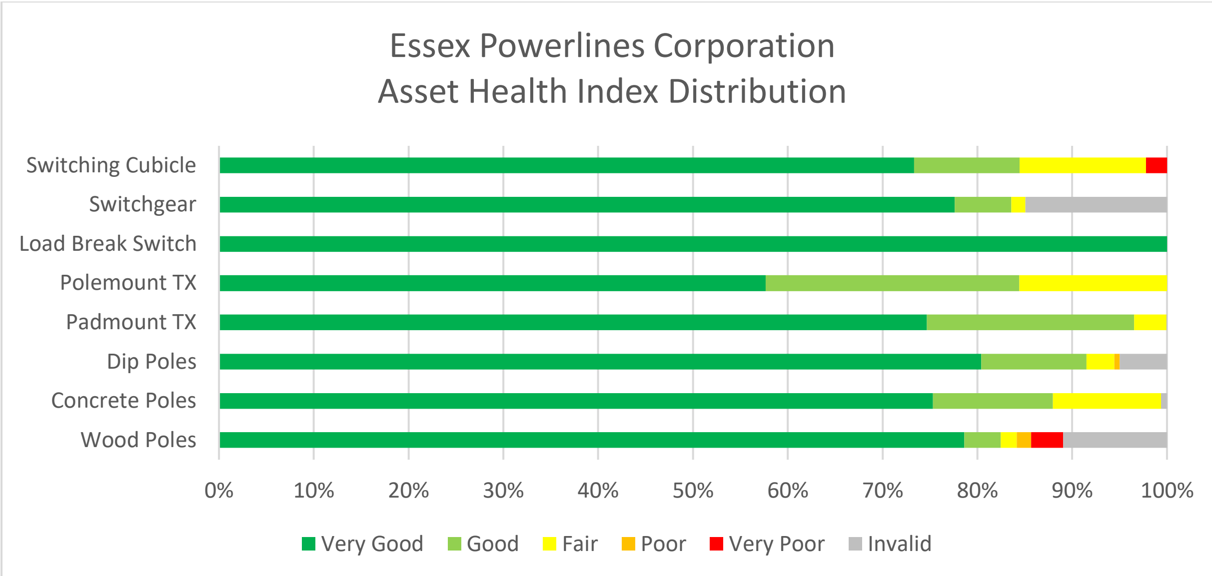


Figure 5.3-9: Asset HI Distribution

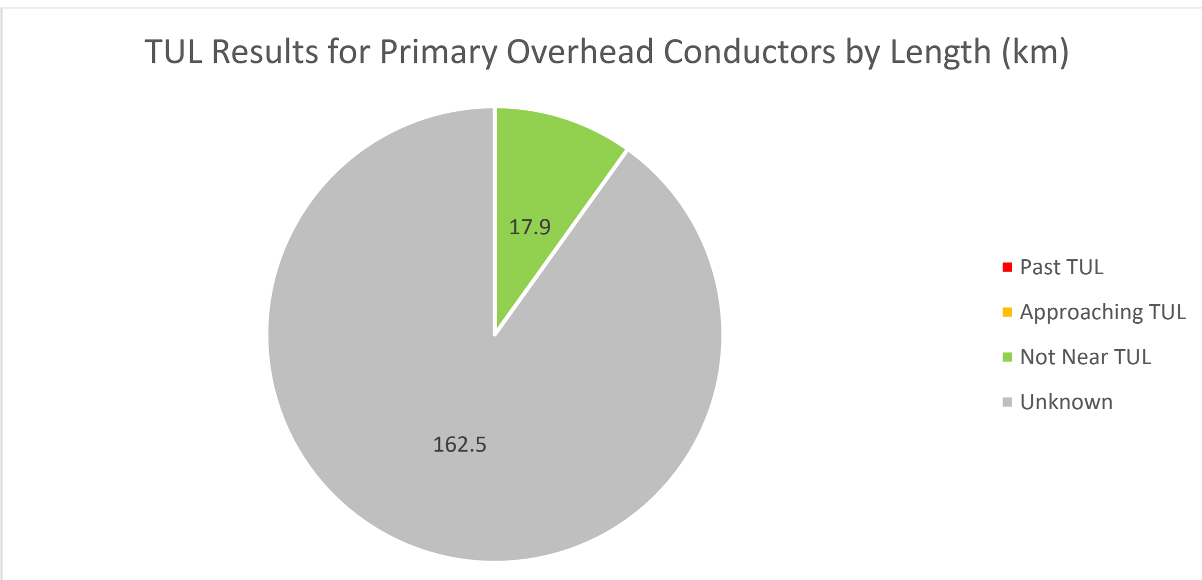


Figure 5.3-10: OH Conductors TUL Results

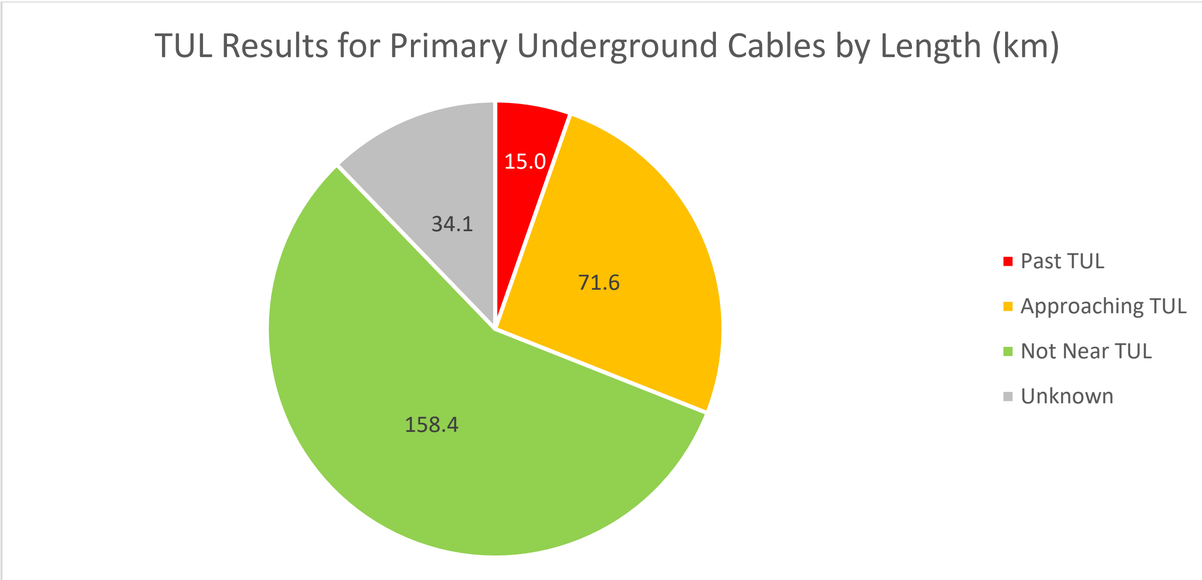


Figure 5.3-11: UG Cables TUL Results

5.3.2.2.3 Asset Risks

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

Asset risks (probability of failure x consequence of failure) are considered as part of EPLC's prioritization process and are ultimately used to determine the prioritized list of capital projects and programs over the forecast period. Additional information on this process can be found in section 5.3.1.

5.3.2.3 Transmission or High Voltage Assets

EPLC does not own any transmission or high voltage assets.

5.3.2.4 Host & Embedded Distributors

EPLC is embedded into the HONI sub-transmission system.

5.3.3 Asset Lifecycle Optimization Policies and Practices

5.3.3.1 Asset Replacement and Refurbishment Policy

EPLC's distribution system maintenance and inspection programs are aimed in part to protect the public from physical, electrical, and environmental hazards by maintaining a schedule of regular asset inspections and maintenance activities. Ontario Regulation 22/04 – Electrical Distribution Safety is a key regulation which requires all LDCs including

EPLC to maintain distribution standards, material standards, and construction verification programs to safeguard the public from hazards associated with the distribution system. EPLC follows all regulatory requirements and guidelines to ensure the distribution system has a low-risk impact on the environment.

EPLC's risk-based asset management process considers risk at each stage in the asset's lifecycle when making decision on the optimal timing of asset repair or replacement. Risk is evaluated by considering both the probability of an event occurring and its consequence. All seven of EPLC's strategic business objectives are considered in this analysis.

Conclusions of risk analyses use a scoring system to select and prioritize capital expenditures. Each potential project is scored in the risk matrix shown in Figure 5.3-1212-12 by considering all seven strategic business objectives and using the following formulation.

$$R_e = R_f + \beta(R_m - R_f)$$

- R_e is the expected rate of return.
- R_f is the risk-free rate of return.
- R_m is the average market rate of return.

By definition:

- Operational β less than 1 is low risk.
- Operational β equal to 1 is average risk.
- Operational β greater than 1 is higher risk.

Probability ↑		Insignificant 1	Minor 2	Moderate 3	Major 4	Catastrophic 5
5	Common/Almost Certain	1.0	1.4	2.1	2.8	4.0
4	Most likely	0.9	1.3	1.8	2.5	3.5
3	Moderate	0.7	1.0	1.4	1.9	2.7
2	Likely	0.6	0.8	1.2	1.7	2.4
1	Rare	0.5	0.7	1.0	1.4	2.0

Consequence →

Figure 5.3-1212: Risk Matrix to Select and Prioritize Capital Expenditures

As part of the asset risk assessment, the asset's age and estimated remaining life are recorded and any concerns are identified. The risk assessment has three components:

- Public safety risk assessment
- Worker safety risk assessment
- Major equipment failure risk assessment

Crew members and the operations manager directly perform risk assessments of assets in the field. Any additional risks identified are populated in risk assessment forms. The inputs come from the operating personnel, shareholders, customer calls, emergency personnel (police, fire), health and safety meetings, other LDCs, and joint-use partners.

Based on the inspection during the risk assessment process, every possible area of concern is noted and prioritized. Various criteria are evaluated, such as concerns with unauthorized entry by public, proximity, clearance for workers, multiple sources of voltage, condition of the assets, presence of PCBs, etc. An overall asset risk ranking is produced as shown in Table 5.3-8. The rankings portray the severity of the risk with each asset by providing the timeframe within which capital work should be done to improve the condition.

Table 5.3-8: Overall Asset Risk Rating

Priority	Low	Medium	High
Intervention Timing	Four (4) to seven (7) years	Two (2) to three (3) years	One (1) year

5.3.3.2 Description of Maintenance and Inspection Practices

Providing a reliable source of electricity to customers within a limited budget are the key pressures faced by LDCs in Ontario. The frequency and timing of distribution system equipment maintenance is a crucial factor in this balance. EPLC relies on a combination of Reliability-Centred Maintenance ("RCM"), predictive maintenance, and cyclical inspections to manage its distribution assets.

RCM focuses on preventing failures with the most serious consequences, while predictive maintenance uses diagnostic methods to schedule maintenance in a timely manner. Integrating the two streams of information along with the asset risk assessment used for capital planning produces an optimal strategy for spending that considers both capital and system O&M costs. As assets are replaced through system renewal investments, the risk exposure on the system is reduced, thus reducing the need for RCM and preventative maintenance. At the same time, other assets on the system continue to age, thus increasing their failure probability and increasing the need for RCM and preventative maintenance. These two competing factors define the complex interactions between system renewal investments and system O&M costs, which EPLC has yet to quantitatively define.

5.3.3.2.1 Reliability-Centred Maintenance

RCM considers the risk of customer outages, asset failure probabilities, methods to reduce the risk failure (probability or consequence), costs, the asset's role in the system, and other measures when selecting a specific maintenance program for an asset. RCM offers the following benefits:

- The consequences of a single event on the distribution system are determined.
- The severity and importance of each component are assessed.
- Failures with the greatest consequences are prevented.
- Unnecessary maintenance is avoided.

The cost associated with each failure is used to predict future costs using failure trends. EPLC has used RCM for the past twenty years to assess and monitor the health of the distribution system assets. RCM is divided into 45 categories for reporting purposes and each outage is entered under the correct category.

5.3.3.2.2 Predictive Maintenance

Predictive maintenance uses innovative technology, software, programs, and practices to identify components that are close to failure or are operating outside of normal ranges. EPLC's predictive maintenance activities include aerial drone surveying, infrared inspections, and line monitors.

Infrared and ultrasonic inspections are both non-destructive test methods used to assess the performance of overhead components and major underground components of EPLC's distribution system. These inspections identify distribution equipment which are close to failure, or which are exhibiting signs of deterioration but still operating normally. Equipment that is close to failure is replaced on a high priority basis. Equipment that is starting to show signs of deterioration is monitored and programs are planned to repair or replace the equipment in the future.

Aerial Drone Surveying is completed by a 3rd party, which includes infrared of assets, vegetation, and the condition of pole tops that EPLC cannot otherwise inspect from the ground. This process captures topography by way of a low altitude aerial drone covering a large geographical area within all four of EPLC's service areas within a matter of a few days. Aerial surveying is a less intrusive approach in comparison to physically walking through ratepayers' properties and provides the ability to perform visual inspections of assets, such as poles and lines that are in areas with limited or no access. Aerial Drone Surveying has added a level of visibility and accuracy of asset health that has been valuable to EPLC's predictive maintenance program and plan.

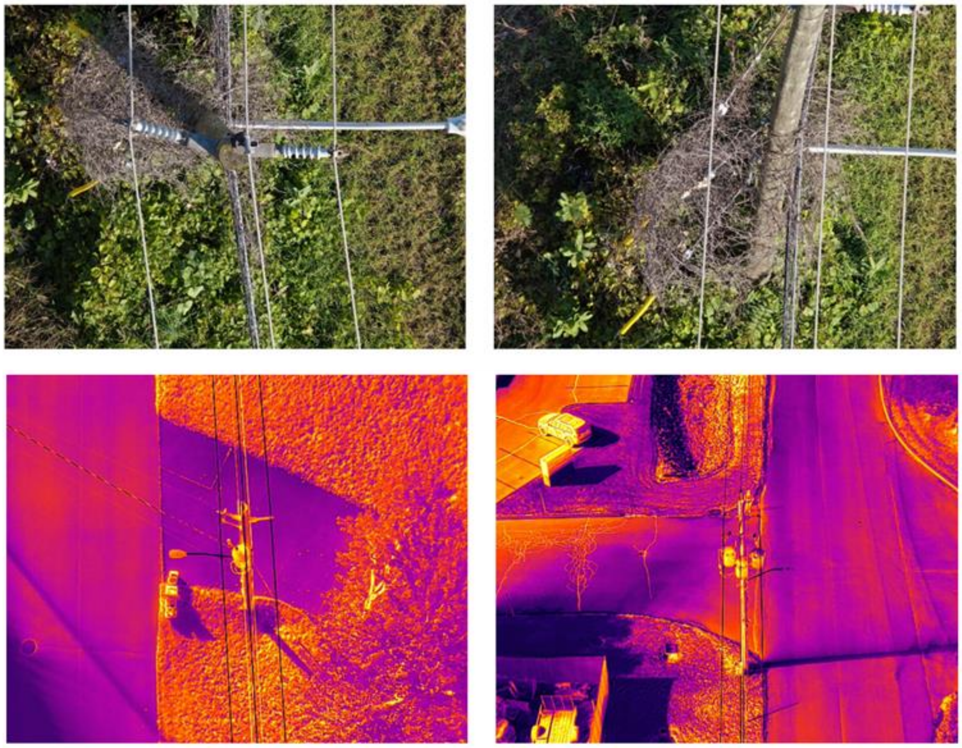


Figure 5.3-13: Examples of imagery and infrared from Aerial Drone Surveying

5.3.3.2.3 Preventative Maintenance

Regular preventative maintenance is performed on distribution assets to assess their condition and ensure proper operation. The preventative maintenance procedure follows standard industry practices and manufacturer recommendations. The assets are tracked in EPLC's database, and the results of the preventative maintenance are used to assess the condition of the equipment. Conditions are evaluated by linemen into three (3) severity categories: low, medium, and high. The database is reviewed for trends and problems requiring immediate actions.

5.3.3.2.4 Inspections

EPLC's inspection programs are based on the inspection requirements listed in Appendix C of the Distribution System Code. Line patrols are performed on a three (3)-year cycle. Overhead transformers are inspected for signs of rust or oil leaks and transformer bushings are checked for cracks or contamination. Ground lead attachments and ground wire on arrestors are checked to ensure proper ground connection is maintained. In addition, transformers are checked for bird/animal nests and tree trimming requirements.

Wood poles are inspected for insect infestation or woodpecker damage; crossarms, pole tops, and pole shells are assessed for deterioration; leaning poles are noted; and a sound test is used to determine the hollowness of the poles. Insulators on the poles are checked for chips, cracks, and contamination. Poles positioned in hazardous locations are also noted.

Load break switches are inspected for corrosion or mechanical deterioration and are maintained regularly. Overhead lines are checked for signs of corrosion, broken strands, abrasions, annealing, and elongation. Line connections to the switches are inspected. Line patrol inspection results are not formally documented. Instead, line staff note any deficiencies during line patrols or trouble calls for immediate or scheduled replacement depending on the severity of the damage or deterioration.

EPLC's underground inspection program covers pad-mounted equipment and underground cable terminations. Underground transformers require very little maintenance and are inspected for paint condition, signs of corrosion, and oil leaks. Transformer bushings are checked for cracks or contamination. Switchgear is inspected for paint, corrosion, and mechanical deterioration and are maintained regularly. Underground cable terminations, which are exposed in pad-mounted equipment and riser poles, are inspected for signs of moisture ingress.

Table 5.3-9: Summary of Inspection and Maintenance Activities

Assets	Category	Activity	Frequency
Overhead distribution assets	Inspections	Visual	Three (3) years
		Infrared	Yearly
		Aerial	Visual & Infrared every three (3) years
	Predictive maintenance	Pole testing	Three (3) years
	Preventative maintenance	Vegetation management	Primary lines every two (2) years. Secondary lines every four (4) years
Underground distribution assets	Inspections	Visual	Three (3) years

EPLC's assets are recorded in a database to manage inspection requirements based on standard industry practices and manufacturer recommendations. This database is reviewed for trends and problems requiring immediate action, and planned actions. Immediate action may be taken if there is a concern for security, public access, or an outage. Inspections also find items like theft of copper from poles as a covered ground wire runs down the outside of some poles to ground equipment. These items are repaired following the inspection.

Inspections are entered on a tablet and can be viewable through secure web portals. A map of inspection results is used by engineering staff to analyze and monitor the asset condition. EPLC staff can use this information to measure deterioration of assets as they age.

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

5.3.3.3.1 Forecasting

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

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

5.3.3.3.2 Prioritization & Optimization

Once the potential investments have been identified, the projects are divided into phases that can be completed in one (1) year. Each project or project phase (if applicable) requires the inputs to the project to be collected. The inputs into the Project Information Plan are costs (savings and spend), risks, and strategic value. All projects are run through the Optimizer Tool to determine the project mix that reduces the most amount of risk while providing the most strategic value.

The strategic value of a project is measured against EPLC's seven (7) asset management objectives:

- Public and employee safety;
- Regulatory (OEB) direction;
- Service quality: SAIFI and SAIDI;
- Financial returns: NPV;
- Legal claims;
- Community image: customer complaints; and
- Environmental.

The risk of project deferral is assessed using the numeric scores for consequence and probability defined in Table 5.3-10 and Table 5.3-11. Risk is calculated as the product of the probability and consequence scores.

Table 5.3-10: Definitions of Numeric Scores Describing the Consequence of Project Deferral

Numeric Score	Financial Risk	Service Quality Risk	Company Image Risk	Legal Risk	Regulatory Risk	Safety Risk (Both Staff and Public Risk)	Environmental Risk
Consequence = 5	>$50,000 in lost revenue or avoided cost	>1.0% overall reduction to SAIFI, SAIDI	>10 written or 50 verbal complaints, general public outcry	Litigation cost <$1,000	Non-reportable compliance issues	Minor WSIB injury	Minor disturbance, no documentation required
Consequence = 4	<$50,000 in lost revenue or avoided cost	<1.0% overall reduction to SAIFI, SAIDI	<10 written or 50 verbal complaints, concerns raised to regulator, coverage by local media	Litigation cost <$10,000	Regulator reportable issues - minor	WSIB reportable injury	Disturbance requiring internal environmental documentation and/or company environmental assistance
Consequence = 3	<$10,000 in lost revenue or avoided cost	<0.5% overall reduction to SAIFI, SAIDI	<8 written or 40 verbal complaints, concerns raised to local government, board of directors	Litigation cost <$50,000	Significant regulatory compliance issues. Notification required.	Medical injury, WSIB reportable, EUSA reportable, Ministry of Labour reportable	Disturbance involving private property and/or potential claims and company environmental assistance
Consequence = 2	<$5,000 in lost revenue or avoided cost	<0.1% overall reduction to SAIFI, SAIDI	<6 written or 30 verbal complaints, multiple concerns made to company	Litigation cost <$500,000	Serious regulatory compliance issues. Fines, direction, or oversight required.	Lost time injury, WSIB reportable, EUSA investigation, Ministry of Labour investigation	Disturbance requiring Ministry of Environment documentation, company environmental assistance and regulatory assistance on site.
Consequence = 1	<$1,000 in lost revenue or avoided cost	<0.05% overall reduction to SAIFI, SAIDI	<4 written or 20 verbal complaints, individual concerns to company	Litigation cost >$500,000	Damaging regulatory compliance issues. Loss of license	Multiple lost time injuries, WSIB reportable, EUSA investigation, Ministry of Labour fine/directive	Disturbance requiring MOE assistance onsite and public evacuation and company environmental assistance.
Consequence = 0	None	None	None	None	None	None	None

Table 5.3-11: Definition of Numeric Scores Describing the Probability of Each Consequence

Numeric Score	Financial Risk	Service Quality Risk	Company Image Risk	Legal Risk	Regulatory Risk	Safety Risk (Both Staff and Public Risk)	Environmental Risk
Probability = 5	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year	More than 4 events per year
Probability = 4	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year	Quarterly, 2-4 events per year
Probability = 3	One event per year	One event per year	One event per year	One event per year	One event per year	One event per year	One event per year
Probability = 2	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years	1 event every 3 years
Probability = 1	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years	1 event every 10 years
Probability = 0	None	None	None	None	None	None	None

The Asset Investment Strategy (AIS) is used to gather the inputs needed for each Project Information Plan. The following items are then used to evaluate and optimize the investment portfolio.

Activity Description
- Identify potential risks.
- Estimate probability of occurrence.
- Define consequences.
- Calculate risk score.
- Compare to project risk threshold.
- Determine alignment of risk exposure with owner's requirements.
- Define risk mitigation strategy if required.
- Select solution.

Define Project/Program Requirements
- Approve selected option(s).
- Determine project/program impact.
- Conduct impact study or change standards, if required.
- Document objective and consequences.
- Identify unique requirements.
- Identify major material requirements.
- Identify appropriate standards.
- Identify resource requirements.
- Identify project milestones and program cycles.
- Assign priority score.

Update/Manage Asset Plan
- Incorporate project/program into asset plan.
- Determine impacts on plan.
- Determine need to reanalyze projects.
- Identify potential portfolio risks.
- Determine probability of occurrence.
- Calculate consequence.
- Calculate risk score of portfolios.
- Compare risk with threshold.
- Determine if impacts are acceptable.
- Adjust plan if required.
- Analyze finances.
- Analyze completion status.
- Analyze performance results.
- Assess variance from plan.
- Identify potential solution to address variances if required.
- Issue/re-issue asset plan.

Maintain Asset Register
- Document individual asset information.
- Describe asset's role and mission in system.
- Define system configuration.

- Validate information.
- Determine validity of data.
- Input data into asset register.

Optimize Maintenance Strategy

- Review asset(s) condition/facts.
- Review asset(s) role/mission.
- Review asset performance history.
- Determine failure modes.
- Determine consequences of failure.
- Assess preventability of failure mode.
- Identify condition-based maintenance activities.
- Identify time-based maintenance activities.
- Identify redesign solutions.
- Determine run-to-failure options where appropriate.

The outputs are analyzed and listed for each year from 2025 to 2029. As new projects are identified, or inputs change the optimized results are rerun to identify new project lists. Table 5.3-12 summarizes the output of the project prioritization tool for material projects planned in the 2025 Test Year. The sum of the risk and strategic objective scores are displayed in the rightmost column and used to rank the projects.

Table 5.3-12: 2025 Test Year Project Prioritization

Category	Project Description	(Strategic Objective Score)	Relative Priority Rank	2025 Planned Expenditure ($ '000)
System Renewal	Pole Replacement Program	4.29	1	1,097
	OH and UG Reactive Replacements	N/A	N/A	257
	Infrastructure Rebuild Program (OH/UG)	2.92	4	1,789
System Service	Metering Replacement	N/A	N/A	395
	Self Healing Grid	3.41	2	1,300
	Conversion – 200A Network Upgrades	1.79	9	274
	DSO Activities	1.59	10	150
	Asset Purchase/Sell between EPLC and HONI	2.04	8	384
System Access	Subdivisions	N/A	N/A	1,080
	Residential Connections/Extension	N/A	N/A	573
	New service upgrades - C & I	N/A	N/A	448
	Municipal Requests	N/A	N/A	212
General Plant	Building Projects	2.89	5	630
	Transportation/Fleet	2.95	3	785
	Tools	2.32	6	100
	IT Hardware/Software	2.08	7	1,678

5.3.3.3.3 Strategies for Operating within Budget Envelopes

The proposed System Renewal projects over the forecast period were identified to maintain system reliability and were paced for implementation based on the funding available for asset renewal and by considering the resources required for project implementation for the type of work predominantly involved. Assets with the highest consequence of failure in service have been prioritized for renewal or rehabilitation during the next five years.

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

5.3.3.3.4 Risks of Proceeding / Not Proceeding

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

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

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

Since its last DSP, EPLC has continued to utilize the various tools and data acquisition to effectively understand the state of its assets. SmartMAP has become a tool used daily to monitor transformer health and understand feeder loading. Alerts within the system provide data when an asset is approaching capacity or momentarily exceeds capacity. These alerts are used to proactively reach out to consumers to better understand what has changed and to dispatch crews to investigate or carry out ad hoc inspections. The continued development of SmartMAP toward real time analysis will assist EPLC in understanding various impacts of load fluctuations on the network and provide data for improved decision making and efficiency.

Additionally, as mentioned in section 5.3.1.2, EPLC developed Work Center, a software suite of modular applications that includes but is not limited to job requests, job estimates, job lookup and job closeout, scheduling, inventory management, and reports. This tool has been imperative for tracking and analyzing utility data, which is then used in the asset management process.

5.3.4 System Capability Assessment for REG

EPLC currently has approximately 219 REG’s connected for a total of 20.26 MW to its distribution system.

5.3.4.1 Applications for Renewable Generators over 10 kW

The following table outlines the known REG connections, that are being processed, for 2024 and 2025. No projects are currently being processed by EPLC beyond 2026.

Table 5.3-13: REG Applications over 10kW being Processed

Feeder	Address	Type	Nameplate Capacity (kW)	Estimated Connection Year
393M27	103 Erie Street, Leamington	Net Metering	60	2024
393M24	96 Princess Street, Leamington	Net Metering	25	2024
56M26	1200 Southfield Drive, Tecumseh	Net Metering	200	2025
56M26	1250 Southfield Drive, Tecumseh	Net Metering	200	2025
56M26	11873 Tecumseh Rd. East, Tecumseh	Net Metering	100	2025
Total Nameplate Capacity (kW)			**585**	

5.3.4.2 Forecast of REG Connections

Table 5.3-14: Five-year REG Forecast

Year	Projected # of Connections	Installed MW
2025	6	0.530
2026	5	0.14
2027	5	0.14
2028	6	0.15
2029	6	0.15
2025-2029 Totals	**28**	**1.11**

5.3.4.3 Capacity Available

EPLC estimates that the following capacity is currently available across its distribution feeders for the following stations. Note that capacity is subject to change at any time. EPLC does not own any stations and the capacity is supplied through HONI stations. The values below are calculated using HONI's Capacity Calculator:

- KEITH TS 23M3 - 4 MW
- KEITH TS 23M4 - 10 MW
- KEITH TS 23M5 – 15.65 MW
- MALDEN TS 24M7 – 9.1 MW
- MALDEN TS 24M9 – 18.75 MW
- MALDEN TS 24M10 – 10 MW
- LAUZON TS 56M25 – 18.46 MW
- LAUZON TS 56M26 – 17.43 MW
- LAUZON TS 56M4 – 18.65 MW
- LEAMINGTON TS 393M24 – 1.15 MW
- LEAMINGTON TS 393M24 – 17.95 MW

5.3.4.4 Constraints – Distribution and Upstream

Currently Hydro One has no constrained feeders.

5.3.4.5 Constraints – Embedded Distributor

EPLC does not have any current embedded distributor constraints.

5.3.5 CDM Activities to Address System Needs

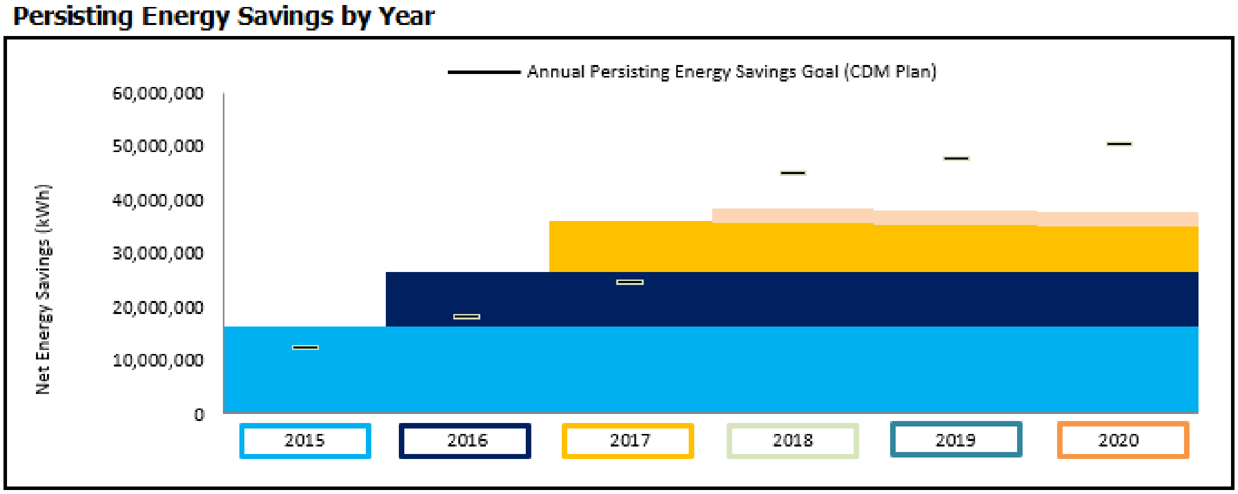
The IESO's Conservation First Framework spanned from 2015 to 2020 and focused solely on energy conservation. This approach suited EPLC since its customer base mostly consists of residential customers. EPLC was assigned a target of 31.43 GWh in net cumulative energy savings over the six (6)-year period and is one of 7 LDCs to hit the target prior to the end of the 2015-2020 CFF, achieving 114.6% of target two years ahead of schedule. EPLC's annual energy savings targets for the years 2015 through 2020 are presented in **Error! Reference source not found.**-14.

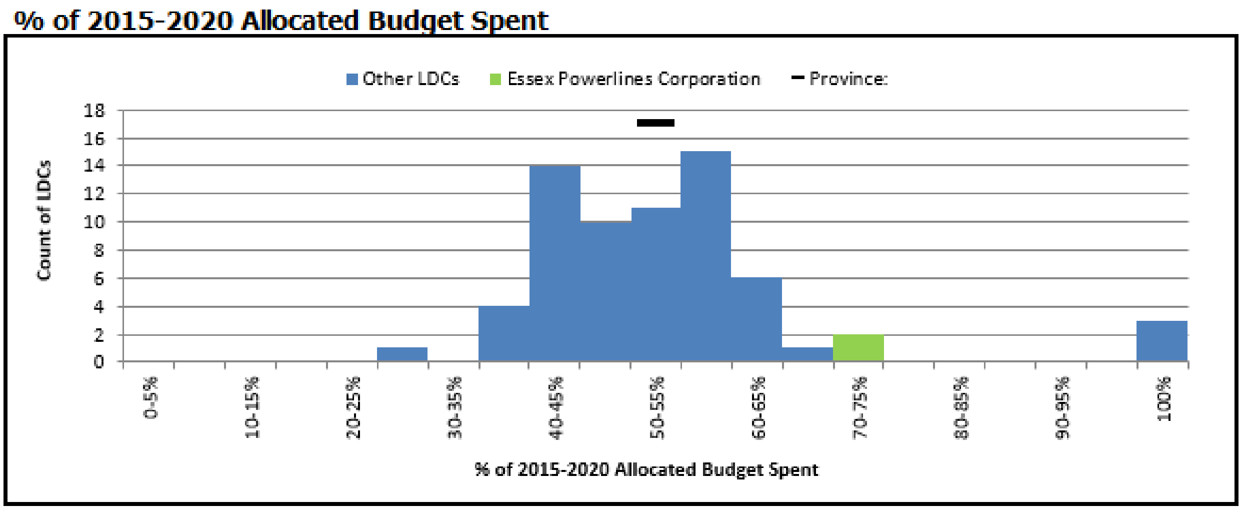
Table 5.3-15: EPLC's CDM Achievement Plan under Conservation First Framework

Year	2015	2016	2017	2018	2019	2020
Annual Energy Savings Target (MWh)	2,660	7,256	10,200	3,837	3,805	3,866

EPLC targeted residential and low-income customers through province-wide Coupon, Heating and Cooling, Home Assistance, and New Construction programs. Small business customers were targeted through province-wide Retrofit, Small Business Lighting, High Performance New Construction, and Audit Funding programs. EPLC also planned three unique programs: the Residential Solar PV program for residential customers, the Social Benchmarking program for residential and low-income customers, and the Smart Thermostat program for residential, low-income, and small business customers. Commercial, agricultural, institutional, and industrial customers were targeted through several initiatives such as the Retrofit, High Performance New Construction, Audit Funding, Process and System Upgrades, and Energy Manager programs. These programs were all funded through the 2015-2020 CDM Framework.

EPLC's dedication to CDM is highlighted in its achievements through the abovementioned program. According to the IESO's Conservation First Framework Monthly Participation and Cost Report, Essex Powerlines achieved 37,630,917kWh in savings by 2020, which equates to 119.7% of its given target. More impressively, EPLC achieved over and above the given target using only 71.27% of its allocated budget. EPLC's proven success and experience in CDM programs has led to the exploration of new and innovative CDM activities, which will continue to be explored in the forecasted period.





5.3.5.1 EPLC's Distribution System Operator Pilot Project

For EPLC, innovative CDM activities are a significant consideration in the distributor's approach to the energy transition and the associated impacts of electrification, decarbonization mandates, and increasing constraints on the local distribution system. Following the Conservation and Demand Guidelines for Electricity Distributors which states that "CDM activities may potentially include non-distributor owned, behind-the-meter solutions"[3], EPLC has undertaken a pilot project aimed at leveraging distributed energy resources to alleviate local constraints and improve local reliability.

EPLC was a successful applicant in response to the Independent Electricity System Operator (IESO) and Ontario Energy Board (OEB) Joint Targeted Call (JTC) for innovative projects focused on deriving value from distributed energy resources (DERs). On March 7, 2022, EPLC was advised that its proposed project, "Essex Powerlines DSO Pilot Project"

[3] Conservation and Demand Management Guidelines for Electricity Distributors, EB-2021-0106, p. 6

(PowerShare), was successful in qualifying for funding through the IESO's Grid Innovation Fund and support from the OEB Innovation Sandbox.

Further regulatory guidance was provided from the OEB to EPLC by way of letter dated May 31, 2022; more specifically that the "activities proposed in connection with Pilot project can be considered distribution activities within the meaning of s. 71(1) of the *Ontario Energy Board Act*, 1998."[4]

PowerShare is aimed primarily at alleviating known constraints on the distribution system as they currently exist in the Leamington service area, which has a high concentration of greenhouses that represent a significant load.

Included in the scope of the pilot project and associated funding are proposed payments to local DER owners for power procured to address local constraints. The pilot project estimated that EPLC would procure up to 5,000MW of electricity over the course of two project phases, spanning approximately 24 months. Alternatively, through project activities, and with a similar aim, EPLC may pay large users of power to curtail load to also alleviate constraints. Project funding is to be used to directly support these activities. Learnings from the project will further the understanding of local energy markets and their value in capital deferral and managing customer costs and will also continue to inform system planning.

<u>PowerShare Background</u>

According to the Ministry of Energy's Powering Ontario's Growth (POG) report, DSO local energy markets are a potential solution for increased distribution reliability, lower cost for customers, and are a facilitator to greater customer participation in transactive energy services, all of which are key components to EPLC's overarching values and goals of supplying reliable, safe, and cost-effective power to its customers. Similarly, according to the IESO's Non-Wire Alternatives Using Energy and Capacity Markets report published in 2020, "DERs can be used as an alternative to both new centralized resource and distribution network capacity, the local benefits they provide may outweigh the economies of scale that have traditionally given centralized resources a competitive edge."[5]

EPLC's PowerShare project looks at unlocking the potential of DERs to meet existing capacity and constraint issues. Approximately 60% of Ontario's greenhouses can be found in the Leamington area, and the high concentration accounts for a significant amount of forecasted load. EPLC currently has access to two feeders (M24 and M27) that service the Leamington community. During high producing months (approximately 6 months of the year), the load on the M27 feeder exceeds a comfortable level (greater than 50%). This limits EPLC's ability to transfer this load to the other feeder in the event of a failure. Existing measures to mitigate issues include requesting access to an additional feeder from Hydro One, however, there are constraints and cost barriers to this process. PowerShare will use the constraints in the Leamington area as a benchmark

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[4] OEB Letter May 31, 2022, attached herein as Appendix A.

[5] IESO, Non-Wire Alternatives Using Energy and Capacity Markets, published May 2020, page 4

to measure non-wires alternative (NWA) performance of a DSO market, all while ensuring safe and reliable service delivery to customers. The project will also consider regional and provincial grid systems for market participation and simulation to showcase Transmission-Distribution (T-D) coordination between DSO and IESO markets.

To achieve a fully functional DSO, prudent system investments need to be made for a successful transition. These investments are necessary for grid modernization and to meet customer expectations of a reliable and affordable grid, but also have the added benefit of helping achieve DSO readiness. These projects are incorporated in EPLC's distribution system plan under the system service category and are relevant for EPLC's everyday operations. The projects include:

Molded Vacuum Interrupters (MVI)- EPLC plans to upgrade its operational cubicle to MVIs. This will replace the manual isolation and switching procedures with mechanical switches that can automatically send status data to a SCADA system. This transition facilitates real-time monitoring, improves decision-making with high granularity data on network conditions, and supports load shifting and balancing. By automating processes that were previously manual, the project aims to increase operational efficiency and safety while providing a richer data set for SCADA systems, enhancing overall network management and resilience.

Reclosers- The introduction of three-phase and single-phase reclosers transforms the way faults are managed and operational flexibility is achieved across the network. These reclosers automatically open and attempt to reclose in the event of faults, such as those caused by transient contacts, and can be operated remotely, providing valuable telemetry data for SCADA systems. This capability not only improves the reliability of power supply by reducing outage times but also enhances the safety of power line technicians by reducing the need for manual interventions in high-risk environments.

AMI 2.0- Interval Meter upgrades leverage the latest technology to offer detailed consumption analysis, improve reliability in communications, and support the enablement of customer-specific reliability measures and system configuration updates. These upgrades facilitate a more accurate load flow analysis, improved outage management, and provide a better customer experience, while also allowing for more effective integration and monitoring of DERs, thus supporting the LDC in managing the network more efficiently and with greater insight into real-time conditions.

While these projects act as standalone grid modernization upgrades to enhance visibility and grid reliability for EPLC, they also form necessary investments for DSO functionality.

5.4 Capital Expenditure Plan

This section details Essex Powerlines' five-year capital expenditure plan within the DSP planning period from 2025 through to 2029. This plan was developed as a direct output of the asset management process described in Section 5.3.

Section 5.4.1.1- Plan vs. Actual Variances for the Historical Period: This section provides analysis of the performance for the DSP's historical period and includes an explanation of variances by investment category.

Section 5.4.1.2- Forecast Expenditures: This section provides an analysis of the expenditures during the DSP's forecast period.

Section 5.4.1.3- Comparison of Forecast and Historical Expenditures: This section provides an analysis of expenditures during the DSP's forecast period vs the historical period.

5.4.1 Capital Expenditure Summary

The capital expenditure plan summary provides an overview of the capital expenditure plan over a 12-year period. This includes 7 historical years and 5 forecasted years. The investments are allocated to one of the four categories based on the primary driver for the investment. Capital investments over the DSP planning period from 2025-2029 have been categorized to align with the four DSP investment categories.

The overview of OEB approved amounts from EPLC's previous filing can be found in Table 5.4-1 and the forecast amounts broken down by category are provided in Table 5.4-2. Further details can be found in Exhibit 2 - Appendix 2-AA and Appendix 2-AB.

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

Category	2018			2019			2020			2021			2022			2023			Bridge Year 2024		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Bgt.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access																					
Gross Capital Spend	1746	2031	16%	1781	1615	-9%	1816	1164	-36%	1836	1629	-11%	1835	2816	53%	2170	3903	80%	2400		
Capital Contributions	-1225	-1167	-5%	-1225	-808	-34%	-1225	-652	-47%	-1225	-1201	-2%	-1225	-1634	33%	-860	-3313	285%	-1439		
Net Capital Expenditures	521	864	66%	556	807	45%	592	512	-13%	611	428	-30%	610	1182	94%	1309	590	-55%	961		
System Renewal																					
Gross Capital Spend	2693	2848	6%	1362	3940	189%	2304	2858	24%	2196	3020	38%	2375	2358	-1%	2593	2549	-2%	2088		
Capital Contributions	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0		
Net Capital Expenditures	2693	2848	6%	1362	3940	189%	2304	2858	24%	2196	3020	38%	2375	2358	-1%	2593	2549	-2%	2088		
System Service																					
Gross Capital Spend	707	900	27%	2186	642	-71%	1126	899	-20%	1342	584	-56%	1144	814	-29%	1622	1447	-11%	3358		
Capital Contributions	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0		
Net Capital Expenditures	707	900	27%	2186	642	-71%	1126	899	-20%	1342	584	-56%	1144	814	-29%	1622	1447	-11%	3358		
General Plant																					
Gross Capital Spend	1037	619	-40%	856	781	-9%	976	971	-1%	968	1267	31%	968	1440	49%	2278	3093	36%	2901		
Capital Contributions	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0	0	0%	0		
Net Capital Expenditures	1037	619	-40%	856	781	-9%	976	971	-1%	968	1267	31%	968	1440	49%	2278	3093	36%	2901		
Total Expenditure, Gross	**6183**	**6398**	**3%**	**6185**	**6978**	**13%**	**6222**	**5892**	**-5%**	**6341**	**6500**	**3%**	**6322**	**7428**	**17%**	**8663**	**10992**	**27%**	**10747**		
Total Capital Contribution	**-1225**	**-1167**	**-5%**	**-1225**	**-808**	**-34%**	**-1225**	**-652**	**-47%**	**-1225**	**-1201**	**-2%**	**-1225**	**-1634**	**33%**	**-860**	**-3313**	**285%**	**-1439**		
Total Expenditure, Net	**4958**	**5231**	**6%**	**4960**	**6170**	**24%**	**4997**	**5240**	**5%**	**5117**	**5299**	**4%**	**5097**	**5794**	**14%**	**7802**	**7679**	**-2%**	**9308**		
System O&M	2872	2240	-22%	2930	2426	-17%	2988	2615	-12%	3048	2526	-17%	3109	2473	-20%	2598	2706	4%	2820		

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

Category	Forecast				
	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access					
Gross Capital Spend	2314	2348	2395	2443	2492
Capital Contributions	-1468	-1497	-1527	-1558	-1589
Net Capital Expenditures	846	851	868	885	903
System Renewal					
Gross Capital Spend	3214	2973	2470	3436	3206
Capital Contributions	0	0	0	0	0
Net Capital Expenditures	3214	2973	2470	3436	3206
System Service					
Gross Capital Spend	2532	2804	5666	4772	4848
Capital Contributions	0	0	0	0	0
Net Capital Expenditures	2532	2804	5666	4772	4848
General Plant					
Gross Capital Spend	3244	2382	2280	2013	1824
Capital Contributions	0	0	0	0	0
Net Capital Expenditures	3244	2382	2280	2013	1824
Total Expenditure, Gross	**11303**	**10506**	**12809**	**12664**	**12371**
Total Capital Contribution	**-1468**	**-1497**	**-1527**	**-1558**	**-1589**
Total Expenditure, Net	**9835**	**9009**	**11282**	**11106**	**10782**
System O&M	3189	3235	3344	3245	3265

5.4.1.1 Plan vs Actual Variances for the Historical Period

Historical variances deliver valuable support and substantiation to future spending and planning for EPLC. Utilizing historical data to improve and enhance EPLC's operations has been, and continues to be, integrated in the planning process.

Along with analyzing historical data, recognizing future trends and engaging stakeholder feedback is imperative to EPLC's planning and therefore has been employed to develop budgets and plans for the forecasted period. The variance analyses below has helped inform future spending projections and analysis for each of the given DSP investment categories.

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

Category	2018 Plan ($ '000)	2018 Act ($ '000)	2018 Var ($ '000)	2018 Var (%)	Justification
System Access, Gross	1,746	2,031	285	16%	The increase in system access expenditures in 2018 was due to unanticipated customer growth. EPLC had planned for 150 new connections, however the actual number of new connections required was 386.
System Renewal, Gross	2,693	2,848	155	6%	Contractor costs that were being used for executing EPLC projects were higher than anticipated.
System Service, Gross	707	900	193	27%	There were unanticipated distribution costs at Leamington TS. This was due to Hydro One building a new TS at Leamington, and then allocating capital contributions that each impacted party needed to pay.
General Plant, Gross	1,037	452	-585	-56%	EPLC deferred the rehabilitation of a parking lot and a vehicle purchase. Additionally, EPLC's locate costs were lower than anticipated.
Total Expenditure, Gross	6,183	6,398	215	3%	N/A
Capital Contributions	-1,225	-1,167	58	-5%	N/A
Total Expenditure, Net	4,958	5,231	273	6%	N/A
System O&M	2,872	2,240	-632	-22%	EPLC did not launch their control room, which would have cost approximately $120,000. Additionally, a contractor was unable to complete all planned Vegetation Management and deferred their Vegetation Management program.

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

Category	2019 Plan ($ '000)	2019 Act ($ '000)	2019 Var ($ '000)	2019 Var %	Justification
System Access, Gross	1,781	1,615	-166	-9%	EPLC did not reach their planned spending allocation for System Access projects due to delays in some planned developments and the deferral of planned municipal projects.
System Renewal, Gross	1,362	3,94-	2,578	189%	EPLC faced higher than average unit costs for pole replacements and a higher volume of replacements required; there were 111 replacements planned and 139 were completed. Additionally, underground replacements had higher than average unit costs. Some deferred amounts originally allocated to System Service expenditures were moved to System Renewal, which is another contributor to the discrepancy between planned and actual expenditures in both the System Renewal and System Service categories.
System Service, Gross	2,186	642	-1,544	-71%	A new feeder project at Malden was deferred as HONI provided access to an underloaded feeder instead. A planned asset purchase from HONI was deferred, as HONI did not sell the assets that EPLC planned to acquire.
General Plant, Gross	856	781	-75	-9%	Variance does not meet materiality threshold.
Total Expenditure, Gross	6,185	6,978	793	13%	See comments above.
Capital Contributions	-1,225	-808	417	-34%	See comments above.
Total Expenditure, Net	4,960	6,170	1,210	24%	See comments above.
System O&M	2,930	2,426	-504	-17%	EPLC saw an improvement in their SAIDI and SAIFI, therefore lowered maintenance, and operating costs. Additionally, some non-critical inspections activities were deferred.

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

Category	2020				Justification
	Plan	Act	Var	Var	
	$ '000			%	
System Access, Gross	1,816	1,164	-652	-36%	Various planned municipal requests were deferred. Additionally, the required new services and upgrades were below average due to the affects of Covid-19.
System Renewal, Gross	2,304	2,858	554	24%	EPLC shifted deferred funds from System Access and System Service expenditure categories to increase System Renewal projects to address assets at risk of failure. Additionally, unit costs were higher than average.
System Service, Gross	1,126	899	-227	-20%	EPLC did not reach the planned System Service expenditure allocation because HONI did not sell assets that EPLC had planned to purchase.
General Plant, Gross	976	971	-5	-1%	Variance does not meet materiality threshold.
Total Expenditure, Gross	6,222	5,892	-330	-5%	See comments above.
Capital Contributions	-1,225	-652	573	-47%	See comments above.
Total Expenditure, Net	4,997	5,240	243	5%	See comments above.
System O&M	2,988	2,615	-373	-12%	Non-critical inspections activities were deferred due to the COVID-19 pandemic.

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

Category	2021				Justification
	Plan	Act	Var	Var	
	$ '000			%	
System Access, Gross	1,853	1,629	-207	-11%	Various planned municipal requests were deferred.
System Renewal, Gross	2,248	3,020	824	38%	EPLC shifted deferred funds from System Service expenditures to System Renewal projects to address assets that were at risk of failure. Additionally, unit costs were higher than average.
System Service, Gross	1,243	584	-757	-56%	EPLC deferred a new feeder project. Additionally, HONI did not sell assets that EPLC originally planned to purchase, which also contributed to the discrepancy between planned and actual System Service expenditures.
General Plant, Gross	927	1,267	299	31%	EPLC completed the parking lot rehabilitation project that was deferred from 2018.
Total Expenditure, Gross	6,270	6,500	159	3%	Variance is below materiality threshold.
Capital Contributions	-1,225	-1,201	24	-2%	Variance is below materiality threshold.
Total Expenditure, Net	5,046	5,299	183	4%	Variance is below materiality threshold.

System O&M	3,048	2,526	-522	-17%	EPLC's Control Room was not yet operating at 24 hours/day, so associated costs were reduced. Non-critical inspections activities and Emergency Response costs were deferred. Additionally, overhead and underground maintenance activities were reduced due to the COVID-19 pandemic.

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

Category	2022				Justification
	Plan	Act	Var	Var	
	$ '000			%	
System Access, Gross	1,835	2,816	981	53%	EPLC faced unanticipated growth. Many of the developments which were previously deferred were carried out in 2022. Additionally, some deferred amounts were shifted from System Service to System Access to accommodate the increase in costs.
System Renewal, Gross	2,375	2,358	-17	-1%	Variance is below materiality threshold.
System Service, Gross	1,144	814	-330	-29%	EPLC deferred a new feeder project. Additionally, HONI did not sell assets that EPLC originally planned to purchase, which also contributes to the discrepancy between planned and actual System Service expenditures.
General Plant, Gross	968	1,440	472	49%	In 2022, EPLC implemented digital work packages and a new phone system which contributed to the increase in General Plant spending. There were some hardware replacements that were deferred in 2021, which were carried out in 2022. Additionally, the actual Fleet costs were higher than anticipated due to impacts of supply chain issues from previous years.
Total Expenditure, Gross	6,322	7,428	1106	17%	See comments above.
Capital Contributions	-1,225	-1,634	-410	33%	See comments above.
Total Expenditure, Net	5,097	5,794	697	14%	See comments above.
System O&M	3,109	2,473	-636	-20%	EPLC's locate costs were lower than anticipated.

Table 5.4-8: Variance Explanations - 2023 Planned Versus Budget

Category	2023 Plan	2023 Act	2023 Var	2023 Var	Justification
	$ '000			%	
System Access, Gross	2,170	3,903	1,733	80%	EPLC faced unanticipated growth. Many of the developments which were previously deferred were carried out in 2023. Additionally, some deferred amounts were shifted from System Service to System Access to accommodate the increase in costs.
System Renewal, Gross	2,593	2,549	-44	-2%	Variance is below materiality threshold.
System Service, Gross	1,622	1,447	-175	-11%	EPLC deferred the purchase of a HONI asset.
General Plant, Gross	2,278	2,920	642	28%	The increase in spend is related to the purchase of new software and hardware. The software included purchase of DER/EV detection software, as well additional IT hardware for new staff. Additionally EPLC purchased another engineering vehicle
Total Expenditure, Gross	8,663	10,992	2,329	27%	The increase is mainly related to the increase in the System Access and General Plant categories.
Capital Contributions	-860	-3,313	-2,453	285%	The increase in capital contribution is related to the increase in the number of customer driven projects within System Access.
Total Expenditure, Net	7,802	7,679	-123	-2%	The increase is mainly related to the increase in the System Access and General Plant categories.
System O&M	2,598	2,706	108	4%	Increases due to increase in tree-trimming and locates.

As 2024 is the Bridge Year, no variance analysis was conducted for 2024.

5.4.1.2 Forecast Expenditures

In total, EPLC plans to spend approximately $52M (net) over the next five-year period. These investment plans are based on the asset management process, including detailed project evaluations and customer preferences.

The following table and figure summarize the planned capital expenditures, by investment category, over the forecast period.

Table 5.4-9: Forecast Net Expenditures by Investment Category

Project/Program	Forecast 2025	2026	2027	2028	2029	Total	Percent of Total
	$ '000						
System Access (net)	846	851	867	885	903	4,352	8%
System Renewal (net)	3,214	2,973	2,470	3,436	3,206	15,298	29%

System Service (net)	2,532	2,804	5,666	4,772	4,848	20,621	40%
General Plant (net)	3,244	2,382	2,280	2,013	1,824	11,742	23%
Total Expenditure, Net	**9,835**	**9,009**	**11,282**	**11,106**	**10,781**	**52,013**	**100%**

5.4.1.2.1 System Access

Expenditures within the System Access category are driven by external requirements such as servicing new customer loads and relocating distribution assets to suit road or municipal authorities. The timing of investments in this category are driven by the needs of external parties and are considered mandatory. Investments in System Access are captured in the table and figures below. Overall System Access investments account for 8% of the total net expenditures.

Table 5.4-10: Forecast Net System Access Expenditures

Project/Program	Forecast					Total	Percent of Total
	2025	2026	2027	2028	2029		
	$ '000						
Subdivisions	1,080	1,097	1,119	1,141	1,164	5,601	47%
Residential Connections/Extension	573	585	596	608	621	2,983	25%
New service upgrades – C & I	448	450	459	468	477	2,302	19%
Municipal Requests	212	216	221	225	230	1,104	9%
Total Expenditure, Gross	**2,313**	**2,348**	**2,395**	**2,442**	**2,492**	**11,990**	**100%**

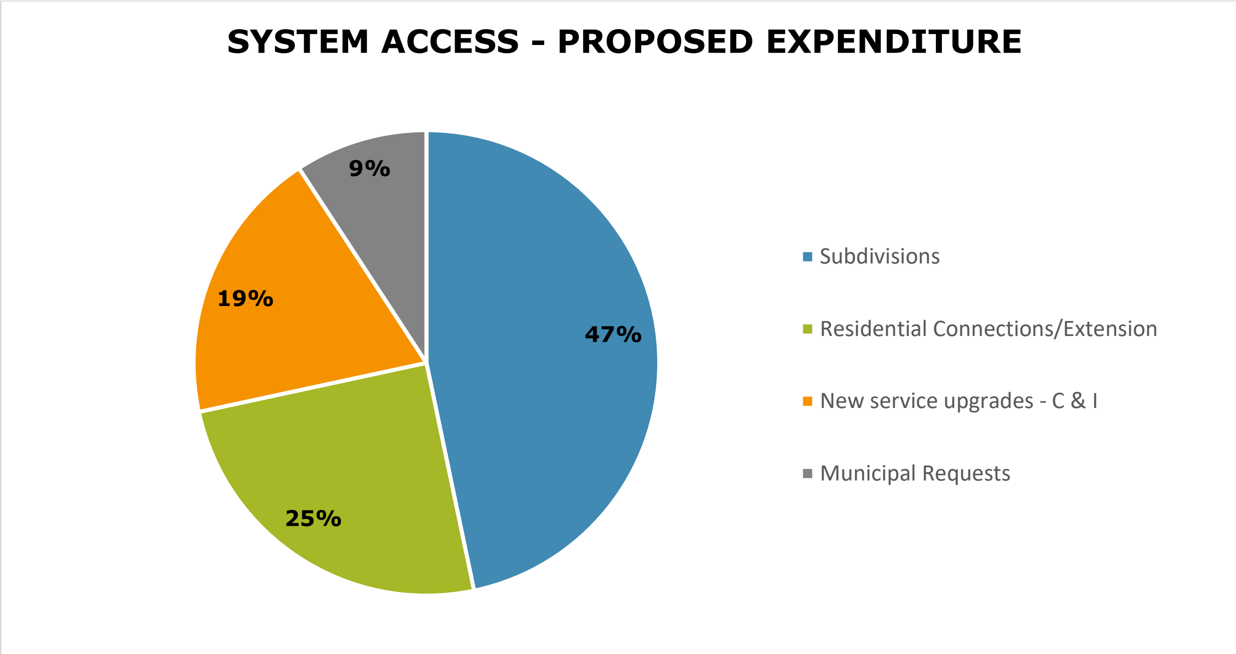


Figure 5.4-1: Forecasted Gross System Access Expenditures by Project

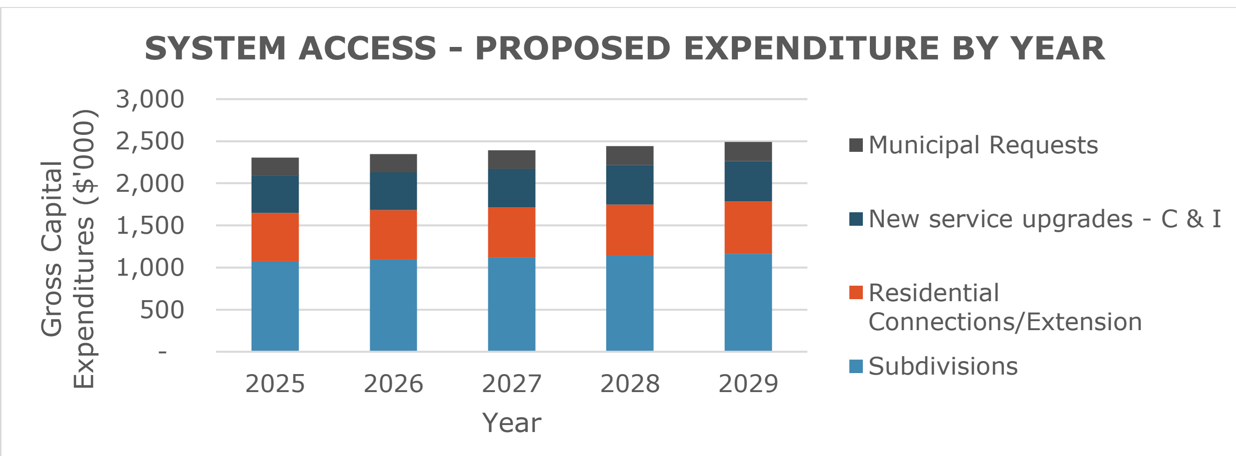


Figure 5.4-2: Forecasted Gross System Access Expenditures by Project by Year

The following describes the projects/programs that contribute towards the system access investments:

<u>Subdivisions (47%)</u>

This program primarily comprises of subdivision projects. The costs in this category involve designing and constructing the civil and electrical infrastructure to accommodate these connections. EPLC is aware of a few subdivision developments beginning in 2025:

Town of Amherstburg

- Rocksedge Phase 2 Subdivision (241 units)

Town of LaSalle

- Lepera Subdivision (7x 3-unit townhomes; Total of 21 units)
- 1780 Sixth Concession Development (47 SF, 22 attached, and 1 commercial). Total of 91 units.
- 5881 Malden Road Condos (x2 buildings; Total 90 units)
- Golfwood Phase 4 and 5 Subdivision (93 units)

Municipality of Leamington

- 125 Talbot St. West Mixed Use Development (small multi-unit 24 units, town homes 53 units, 3 apartment buildings totalling 216 units). Total of 293 units
- 17 Robson Road Mixed Use Building (10 units)
- 3 Coronation Avenue (12 units)
- 21 Robson Road (60 units)
- Ellison Coco Development Phase 2 (61 units)
- 111 Sherk Street Mixed Use Building (4 Buildings totaling 276 units)

<u>Individual Secondary Services (24%)</u>

This category primarily represents new services for individual customer requests. This involves fulfilling customer requests for new services or upgrade of existing services. Since the projected growth in EPLC's service territory over the forecast period remains stable compared to historical numbers, services are projected to be levelized over the forecast period growing in accordance with inflation.

<u>Expansion & Individual Secondary C&I (20%)</u>

C&I connections relate to the planned/forecasted work required to facilitate connection of new C&I customers to the distribution system as well as expand existing services, where required. EPLC is aware of a few C&I developments beginning in 2025:

Town of Amherstburg

- Commercial Development at the old Duffy's site (1 to 2 Commercial units)

Town of LaSalle

- Heritage Plaza Commercial Development (Approx. 20 commercial units)
- 6150 Malden Road. New 3-storey hotel.
- LaSalle Landing Waterfront Development. (3 commercial services)

Municipality of Leamington

- New Grocery Store at 126 Talbot St. South.
- Mixed Use Development at 320 Erie St. South (WFCU and a new restaurant; Total of 2 commercial units)

- 111 Sherk Street Mixed Use Building (4 buildings totaling 12 commercial units)

Town of Tecumseh

- PJ Cecile Pump Upgrade at 14080 Riverside Drive East

Municipal Requests (9%)

These projects involve road authority work where overhead and/or underground lines are relocated to accommodate road widening projects driven by municipalities. This also involves any joint use work that may be required, and recoverable expansions or extensions to the distribution system that may be needed for customer driven requests. Over the forecast period this is based on historical averages other than where specific projects are known at the time of creating this DSP. EPLC is aware of a few Municipal projects beginning in 2025:

Town of LaSalle

- Howard/Bouffard Master Drainage Plan. Relocation of poles, guy wires, and hydro cable may be required.
- Malden Rd. Improvements (Meagan to Normandy). Relocation of poles, guy wires, and hydro cable may be required.

Municipality of Leamington

- Leamington Streetscaping Project. Requires the relocation of poles, wires, and customer secondary services.

Since the level of investment required under this investment category is largely dependent on third-party requests, the level of actual investments for System Access may slightly deviate year-to-year from the proposed investment levels, depending upon the number of requests received.

Additional Meter Installations (<1%)

This program covers a change of use of the metering for commercial or residential buildings. For example, a building that is bulk metered may change to multiple individual meters, or a commercial building has opened a new retail space that requires an additional meter. EPLC is estimating that they expect 6 to 10 of these requests per year based on historical trends.

5.4.1.2.2 System Renewal

Expenditures within the System Renewal category are largely driven by the condition of distribution system assets and are driven by the overall reliability, safety, and sustainment of the distribution system. EPLC conducted an ACA to inform decisions for System Renewal within this DSP. The output of these assessments and processes led to targeted programs for capital expenditure and prioritization of System Renewal. Investments in System Renewal are captured in the table and figures below. Overall System Renewal investments account for 29% of the total net expenditures.

Table 5.4-11: Forecast Net System Renewal Expenditures

Project	Forecast					Total ($ '000)	Percent of Total
	2025	2026	2027	2028	2029		
	$ '000	$ '000	$ '000	$ '000	$ '000		
Pole Replacement	1,097	811	250	1,173	884	4,215	28%
Overhead and Underground infrastructure rebuilds	1,789	1,665	1,698	1,732	1,963	9,367	61%
Overhead reactive replacements	144	147	151	154	158	754	5%
Underground reactive replacements	113	116	119	121	124	593	4%
Misc. Capital Costs	71	72	74	75	77	369	2%
Total Expenditure, Net	**3,214**	**2,973**	**2,470**	**3,436**	**3,206**	**15,298**	**100%**

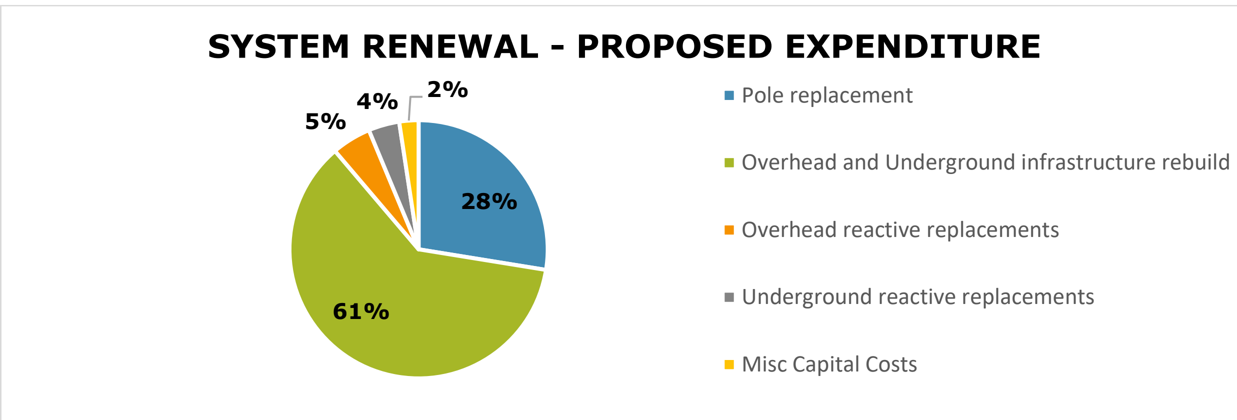


Figure 5.4-33: Forecasted Net System Renewal Expenditures by Project

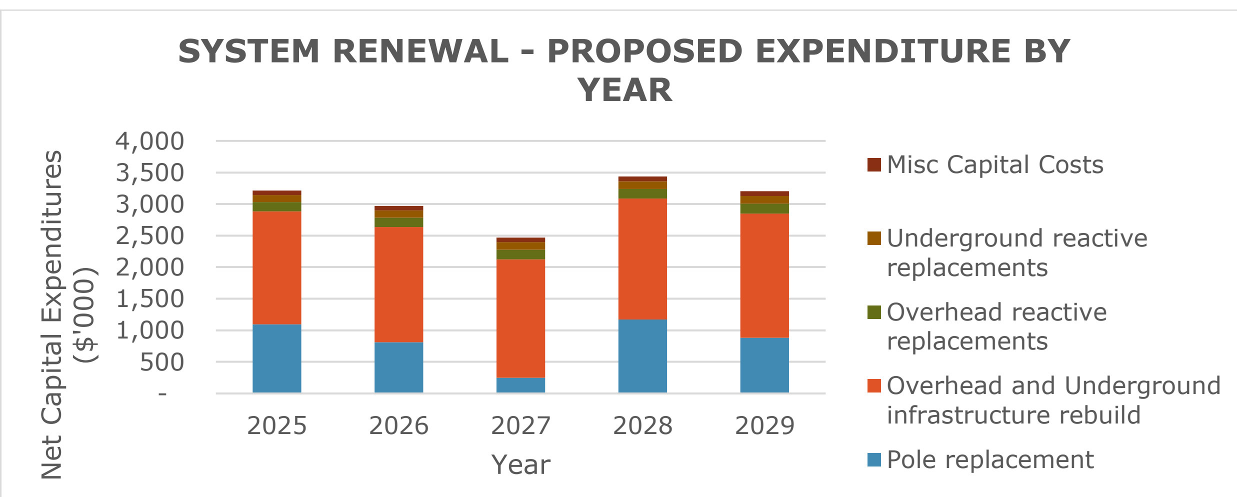


Figure 5.4-44: Forecasted Net System Renewal Expenditures by Project by Year

The level of investments required over the forecast period was determined using EPLC's AM process, which is described in detail in Section 5.3.1, and the ACA was used to assist in prioritizing investments in asset classes. Major programs within the System Renewal category include the renewal and replacement of deteriorated assets at the end of their service life, including poles, transformers, overhead infrastructure, and underground cable. Unplanned System Renewal projects are also budgeted each year to allow for replacement of electrical infrastructure damaged by inclement weather, unclaimed vehicle accidents or those identified through inspections or testing as needing immediate replacement.

Overall, the observed increase in System Renewal spending over the forecast period is driven by the corporate objective to maintain or improve the reliability of the distribution system.

The system renewal programs are summarized below:

<u>Underground Infrastructure Rebuilds (61%)</u>

This investment category addresses both overhead and underground rebuilds.

This investment category includes the replacement of a portion or entire length of primary overhead conductor, poles, pole mount transformers and associated equipment that have been deemed in need of replacement due to having a high risk of failure and are at end of life, as informed through inspections and the ACA results.

This investment category includes the replacement of primary underground cable, padmount transformers and associated equipment that have been deemed in need of replacement due to having a high risk of failure, as identified through inspections and the ACA results. This program also installs ducting where needed, ensures adequate transformation for future system needs, provides looped feeds where practical, and replaces XLPE cable with TRXPLE to provide an enhanced quality of conductor with a longer typical useful life.

<u>Pole Replacements (28%)</u>

This investment category includes the replacement of individual poles and associated equipment that have been tested or deemed in need of replacement due to having a high risk of failure. ACA results are used to help inform which poles may need replacing in the forecast period. Pole height and class, conductor size, framing, and transformer size are all optimized when completing these projects to ensure future system needs are accounted for.

<u>Overhead & Underground Reactive Replacements (9%)</u>

This investment category includes unplanned capital jobs that arise due to asset failure, customer complaints or compliance issues. This program deals with storm damage and repairs that are capital in nature including pole, transformer, conductor, switch, and switchgear replacements.

Misc. Capital Projects (2%)
This small expenditure category includes investments for small remedial work and other minor ad-hoc investments that were not originally planned for.

5.4.1.2.3 System Service

Expenditures in the System Service category is driven by the need to ensure that the distribution system continues to meet its operational objectives (such as reliability, grid flexibility, and DER integration), while being able to address future anticipated customer electricity requirements. Investments in System Service are captured in the table and figures below.

Table 5.4-12: Forecast Net System Service Expenditures

Project/Program	Forecast					Total	Percent of Total
	2025	2026	2027	2028	2029		
	$ '000						
Network Upgrades (200 A)	274	288	319	351	371	1,603	8%
Metering	395	403	411	419	428	2,056	10%
AMI 2.0	-	-	2,572	2,504	2,525	7,601	37%
Asset Purchase/Sell between EPL and HONI and Capacity Increase - Incremental	384	768	884	-	-	2,036	10%
FIT & Generation Connections	29	30	30	31	32	152	1%
Self Healing Grid	1,300	722	741	756	776	4,295	21%
DSO (GIF) Activities	150	153	156	160	163	782	4%
Switchgear/cubicle upgrades	-	439	552	552	555	2,098	10%
Total Expenditure, Gross	**2,532**	**2,804**	**5,666**	**4,772**	**4,848**	**20,622**	**100%**

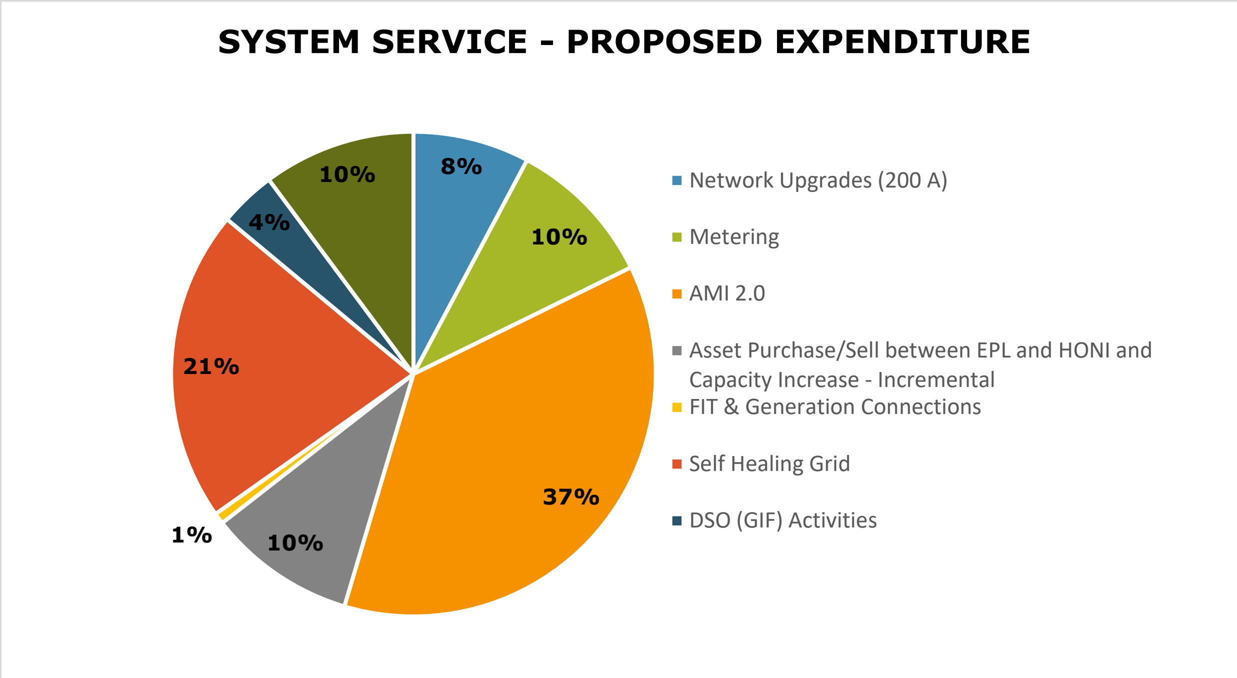


Figure 5.4-55: Forecasted Net System Service Expenditures by Project

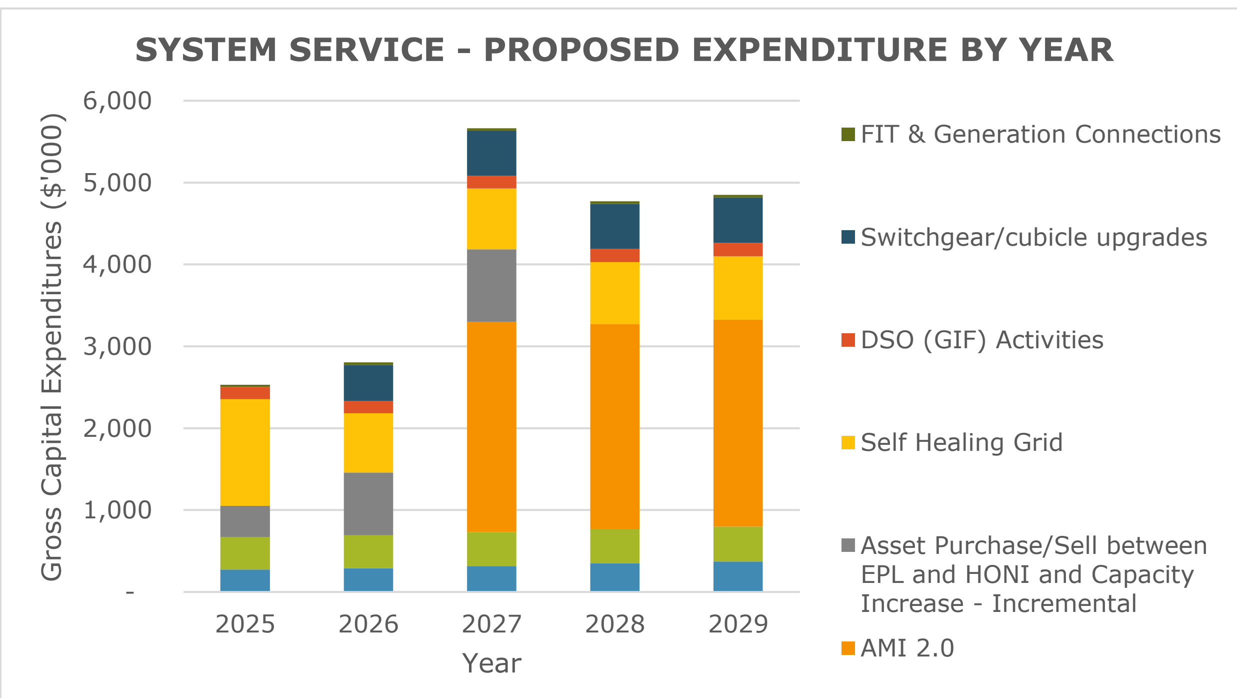


Figure 5.4-66: Forecasted Net System Service Expenditures by Project by Year

System Service investments represent 40% of EPLC's overall budgeted net capital expenditures over the forecast period. These programs are summarized below:

<u>AMI 2.0 (37%)</u>

The Advanced Metering Infrastructure 2.0 program (AMI 2.0) is a multi-year investment to replace EPLC's legacy AMI 1.0.

The AMI 2.0 project consists of replacing both the software and hardware components of EPLC's existing AMI system. This investment is expected to maintain and improve billing accuracy, optimize network communications, reduce manual meter reads (only meters in an electrical room that block the signal from getting out would need manual reads), provide faster response times to disconnection/reconnection requests, provide more accurate outage information, and provide customers with a modern AMI platform to meet foreseeable customer needs over the lifetime of the assets. The program will employ the newest generation of equipment to meet current needs and provide a platform to address foreseeable future needs over the investment's service life.

EPLC forecasts capital expenditures of approximately $7.6M for this investment in the 2025-2029 period (note additional cost will be incurred beyond 2029 to complete the full AMI2.0 rollout). The AMI 1.0 system comprises approximately 31,453 meters, of which approximately 68% are between 11-15 years old and will soon reach or have already reached the end of their expected 15-year service. life. The physical deterioration of meter components and meter failures pose impacts and critical risks to EPLC affecting various elements of its business including:

- Reduced billing reliability and resultant customer dissatisfaction from estimated billing and billing corrections.
- Increasing costs associated with reactive individual meter replacements due to failed meters.
- Higher labour costs for unplanned individual failed meter replacement relative to mass meter replacement.
- Replacement of failed meters with obsolete technology, and the associated lost opportunities for future benefits that address foreseeable needs; and
- Regulatory noncompliance.

The new AMI system also provides numerous benefits to both the utility and the customer. With edge computing there is now a way to allow customers to download apps and link to their meter to better understand consumption patterns and load disaggregation. EPLC can better understand load characteristics of consumers, proactively monitor transformers and their loading, understand EV/DER patterns, and complete remote disconnects. It can also improve power quality and monitoring when issues arise by utilizing existing meters to retrieve pertinent data rather than have to install additional equipment. The new system also provides flexibility with multi-tenancy so that EPLC can explore shared services within the headend system and share costs with other likeminded LDCs.

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

- The AMI 2.0 solution includes a 100% coverage model to be able to read all meters with the proposed installation.
- Less truck rolls for certain disconnects/reconnects as it can be remotely done.
- Less collectors for AMI data, meaning reduced monthly costs for backhauling meter data.
- No meter re-verifications needed for 10 years after meters are installed.,
- No more RMA's and associated costs to replace single meters which are non-communicating.

Self Healing Grid (21%)

This investment category is for the addition of remote fault indicators, reclosers/smart switches and the equipment and time necessary to design, configure and install them in EPLC's distribution system. The aim of these projects is to reduce interruptions related to the distribution/transmission plant owned by HONI. EPLC plans to install reclosers at strategic points throughout its distribution system to help enable the Self-Healing Grid. In 2021, EPLC was a successful applicant in Natural Resources Canada's Renewable Energy and Electricity Technologies – Smart Renewables and Electrification Pathways Program (SREP), and as such, has received a grant totalling $1,500,313 to further implement its Self-Healing Grid project. The grant has helped accelerate the progress of the self-healing grid, with an additional nine 3-phase reclosers and eleven 1-phase reclosers installed in 2022 and 2023. EPLC will continue to work on developing and implementing its self-healing grid project in an effort to modernize its distribution system.

Metering (10%)

This program is related to the supply, installation, and maintenance of revenue meters installed at each customer service point for retail settlement and billing purposes for all customers connected to EPLC's distribution system.

Network Upgrades (8%)

This investment accounts for the potential upgrade from 100A to 200A for residential homes. This will accommodate for the increase in customers adding new load, such as EV charging stations, electric heat pumps, and other electrical intensive services in their homes. Due to the shift to electrification underway in Ontario, it is now industry practice to install 200A services to new residential homes.

Asset Purchase/Sell between EPLC and HONI and Capacity Increase – Incremental (10%)

EPLC also anticipates that HONI asset purchase(s) will be required to facilitate long-term load transfer removal as well to accommodate significant HONI work within EPLC service areas. This includes two feeder sections in Amherstburg and two feeder sections in Leamington.

FIT & Generation Connections (1%)

This project is to accommodate the connection of renewable energy generation to EPL's distribution system. This program includes FIT connections (10 kW up to 500 kW) and generation connections (greater than 500 kW), but does not include microFIT connections (less than 10 kW).

DSO (GIF) Activities (4%)

This investment program relates to EPLC's PowerShare project. PowerShare is a project designed to demonstrate the ability of a Local Distribution Company to assume Distribution System Operator (DSO) market functions through a scalable market design to activate Distributed Energy Resources (DER) flexibility locally. This transformation will allow DER owners to profit from their investments by selling surplus or stored generation to bolster grid resilience using the NODES platform.

Switchgear/cubicle upgrades (10%)

The purpose of this program is to replace live-front switchgear units that have failed or are at the end of their service life due failure risk. Through its thorough preventative maintenance program, EPLC reviews the condition of all switchgear units continuously to limit failure and maximize safety via infrared and physical inspection. Budgeting is reviewed annually based on preventative maintenance program findings and availability of resources.

5.4.1.2.4 General Plant

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

Table 5.4-13: Forecast Net General Plant Expenditures

Project/Program	Forecast					Total	Percent of Total
	2025	2026	2027	2028	2029		
	$ '000						
Building Expenses	630	473	500	525	551	2,679	23%
Office Furniture	25	25	25	25	25	125	1%
Stores Equipment	26	27	27	28	29	137	1%
Transportation/Fleet	785	815	820	805	750	3,975	34%
Tools	100	72	74	76	79	402	3%
IT - Hardware	635	216	113	153	68	1,186	10%

IT - Software	1043	755	720	400	322	3,239	28%
Total Expenditure, Net	**3,244**	**2,382**	**2,280**	**2,013**	**1,824**	**11,742**	**100%**

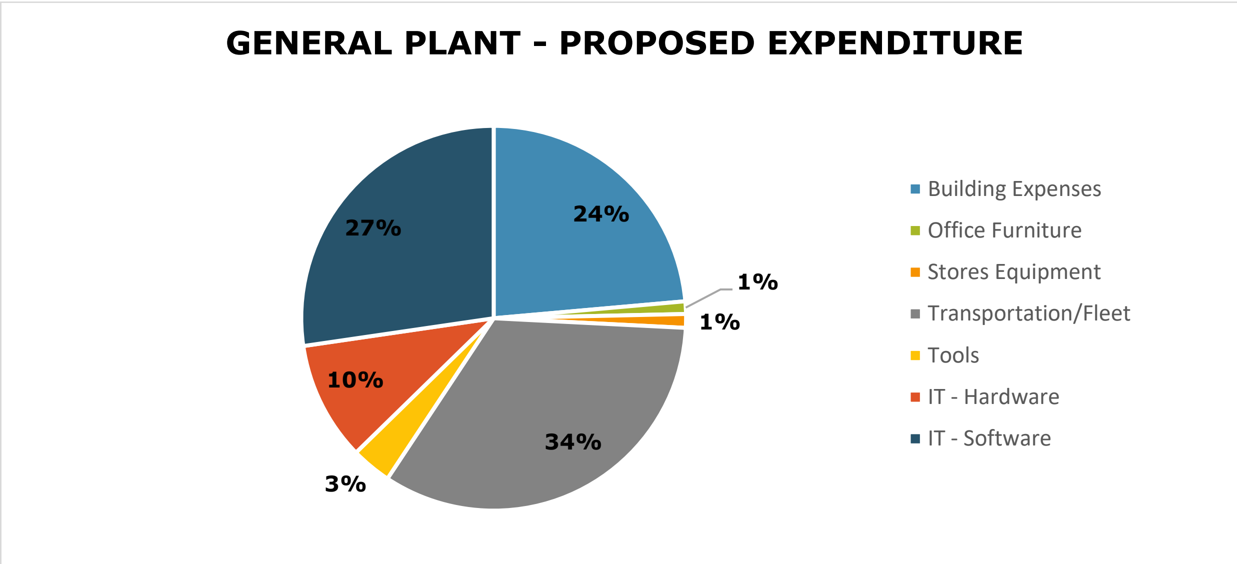


Figure 5.4-77: Forecasted Net General Plant Expenditures by Project

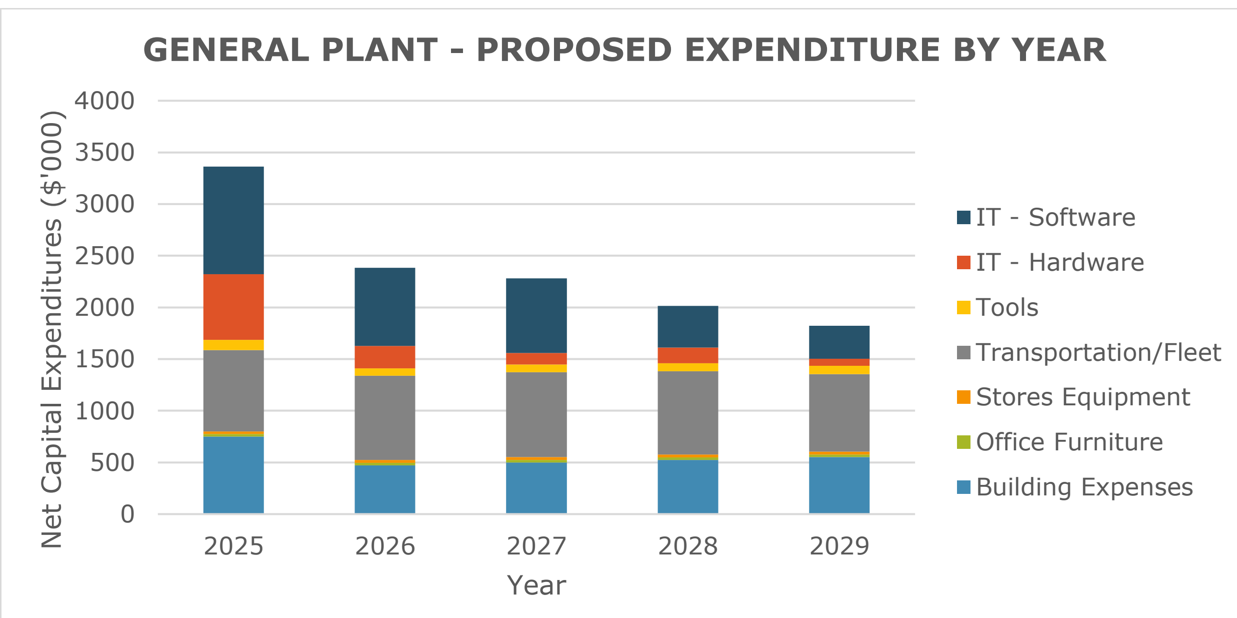


Figure 5.4-88: Forecasted Net General Plant Expenditures by Project by Year

General plant investments represent 20% of EPLC's overall budgeted net capital expenditures over the forecast period. The budget is allocated amongst the four following programs:

Transportation/Fleet (34%)

This investment category includes investments in EPLC's passenger vehicles, bucket trucks and trailers. The proposed investments are based of inspections, mileage, age, and use of vehicle. The following table outlines which vehicles will be replaced in the 2025-2029 period:

Table 5.4-14: Vehicles to be replaced in 2025-2029 period

Vehicle	Replacement Year
Unit #77 - Pickup Truck	2025
Unit #80 - Pickup Truck	2025
Unit #110 - RBD	2025
Pole Trailer	2025
Unit #78 - Pickup Truck	2026
Unit #79 - Pickup Truck	2026
Unit #111 - Single Bucket Truck	2026
Unit #113 - RBD	2027
Unit #85 - Pickup Truck	2027
Replace 2 X Engineering Vehicles	2027
Unit #81 - UG Truck Enclosed Bed	2028
Unit #84 - UG Truck Open Bed	2028
Single Axle RBD	2028
SDP Backyard RBD	2029
Stringing Trailers	2029
Landscape Trailer	2029

IT- Software (28%)

Investments in this category include general upgrade and replacement of end-of-life software assets, other business process efficiencies, enhancements to cyber-security of the utility, and adding modules to existing software solutions. IT technology and cybersecurity threats are continuously evolving as the sector shifts towards technological advancement. As such, upgrades to technology are required on an annual basis to ensure relevancy and compliance of standards. The following are examples of the software projects EPLC plans to undertake:

- General software upgrades
- CIS upgrade
- UtiliDE Map Interface
- GIS – Utility Network Design
- GP upgrade and replacement
- OMS & SCADA enhancements
- Website and customer experience enhancements

Some of these projects are also necessary to support the goals of the organization by providing enhanced support and better connectivity to customers, while others provide more granular data of the distribution system to help improve customer relations and maintain integrity of the system.

Building Expenses (23%)

This category comprises of general investments and improvements to EPLC's office building(s), which is critical to EPLC's 24/7 operations. Project identification is based on asset failures, inspection, and other assessments. In addition, to further inform and refine its investments, EPLC is planning a third-party building condition assessment that is planned to be completed in 2025. Subsequent inspections and reports are to be completed to ensure building assets are replaced at the appropriate time. Based on its assessments, this will include:

- HVAC replacement
- Roof rehabilitation
- EV Charging Infrastructure at its offices and depots
- Building upgrades based on inspection findings
- Additional fleet garage
- Repair/replacement of gate and fencing
- Yard extension
- Pavement and cement pad extensions
- Upgrade of damaged transformer area
- Renovation of East Mezzanine
- Garage door replacements
- Building Envelope inspection
- Other minor building and facility remedial and upgrade projects.

IT- Hardware (10%)

Investments in this category include general upgrade and replacement of end-of-life hardware assets. This is important to ensure compliance with cybersecurity standards, as well as workforce optimization and efficiency. For example, replacement and purchase of laptops for new and existing staff. In addition, EPLC plans to upgrade its server hardware which has reached its end of life. The following are examples of the IT hardware projects EPLC plans to undertake:

- General rolling hardware stock replacements
- Server hardware upgrade which will ensure that EPLC complies with the OEB's cyber security framework.
- AI pilots
- Internet upgrades
- Display enhancements
- SCADA & IOT data centre upgrades

Tools (3%)

This category includes investments in various tools and small equipment necessary to execute the 24/7 operations and maintenance activities of the engineering, operations, and stores departments, while also adhering to safety standards.

Stores Equipment (1%)

This category includes investments in various equipment necessary to perform the 24/7 operations and maintenance activities of the engineering, operations, and stores departments.

Office Furniture (1%)

This category comprises of general investments and improvements to furniture located within EPLC's offices to enable EPLC staff to continue to perform their jobs safely and efficiently.

5.4.1.2.5 Investments with Project Lifecycle Greater than One Year

EPLC strives to complete projects on a yearly basis and plans accordingly. On occasion, due to circumstances beyond EPLC's control, a project may have to carry into the next fiscal year. When this occurs, the projects are known as WIP (work in progress) and can vary in value from hundreds of dollars to thousands of dollars. In most cases, the project can be closed as substantially complete when the bulk of the assets are installed and operating sufficiently. A new project is then opened in the following year with the same job number and an added dash one (-1) to link the two jobs (Ex.: 23-1234 closes and 24-1234-1 is opened) and complete any outstanding work. An example of when this would occur is the installation of metering or the connection of a customer secondary to a newly installed transformer. For the projects that are not closed as substantially complete, the associated costs are carried forward to the following fiscal year. EPLC strives to keep the WIP category as low as possible and is investigating the potential of including the projected WIP value as a budgetary line item for the following year as deferred capital.

5.4.1.3 Comparison of Forecast and Historical Expenditures

A comparison of EPLC's capital expenditures in the DSP's forecast period as compared to the historical period is provided in the following subsections.

5.4.1.3.1 Overall Capital Expenditures

The overall net capital expenditure trends over the 2018 to 2029 period are exhibited in Figure 5.4-9. The average overall capital expenditures forecast is approximately 63% higher than the historical plus bridge-year average. This is largely a result of the AMI 2.0 deployment within the System Service expenditure category as well as increased spend related to fleet replacements within the General Plant expenditure category.

When comparing overall net expenditures over the historical and forecast periods, it is important to compare expenditures on a like-for-like basis as much as possible. Comparing from 2021 to 2024, the average overall capital expenditures forecast drops to 50% increase. This better compares the forecast costs of labour and materials with what has been seen in the recent historical period as materials in many cases have increased by 40% since 2021, with labour costs also increasing significantly.

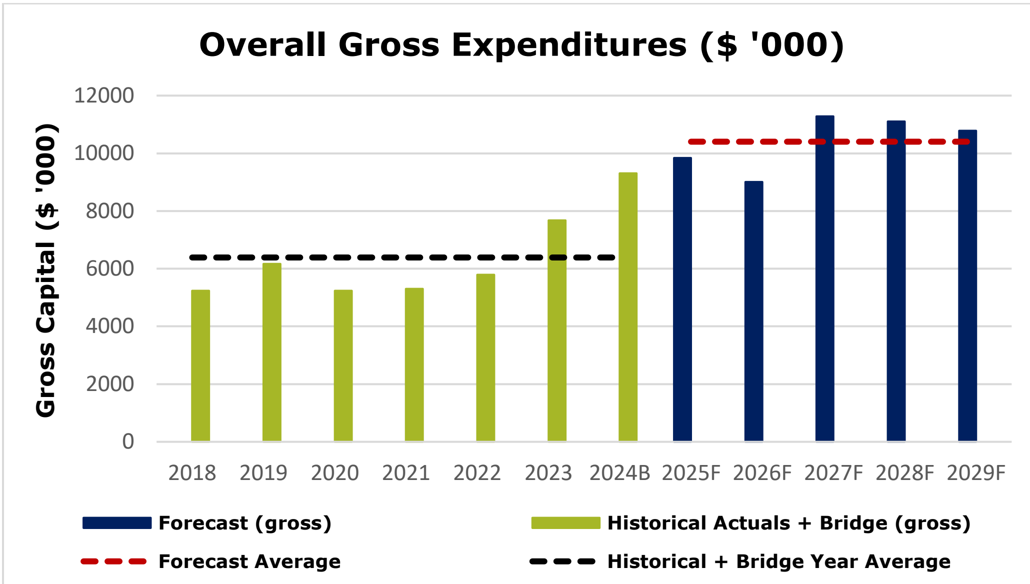


Figure 5.4-9: Overall Expenditures Comparison

5.4.1.3.2 System Access

As shown in Figure 5.4-10, EPLC's System Access forecast average is 8% greater than the historical plus bridge year average. The historical System Access trend is variable year over year due to the unpredictability of customer connection service requests, externally initiated subdivision and relocation projects, as well as third-party delays, deferrals, cancellations, and/or the introduction of new or additional work.

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

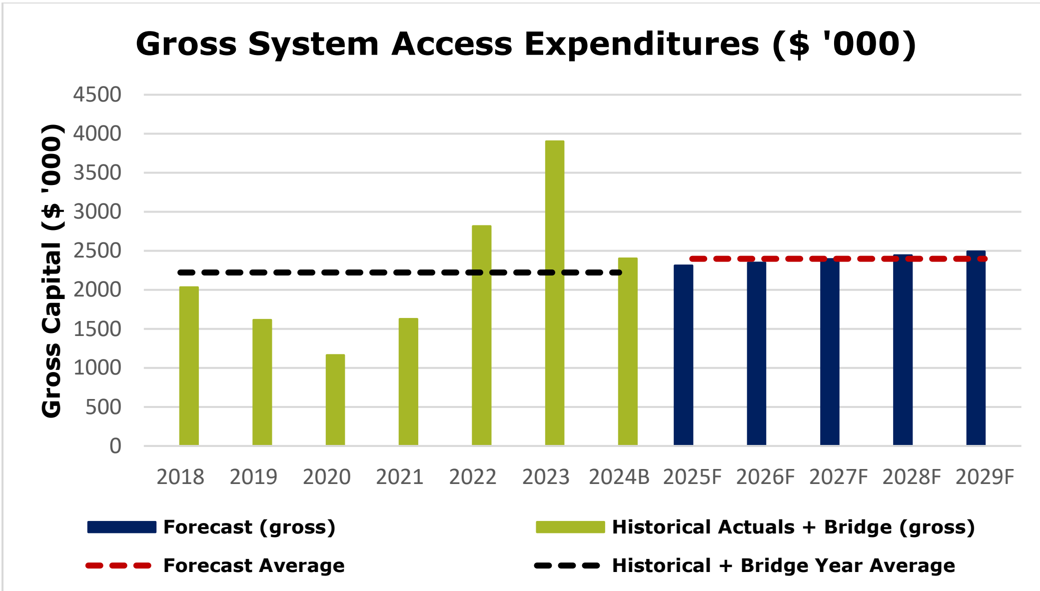


Figure 5.4-10: System Access Comparative Expenditures

5.4.1.3.3 System Renewal

System Renewal expenditures are impacted by planned capital investments and the objective to address any condition-based maintenance activities within the asset base to meet the customer's expectations regarding performance and reliability. As shown in Figure 5.4-11, the forecast average for System Renewal is 9% higher than the historical plus bridge year average.

The level of forecasted System Renewal spending is reflective of the ongoing efforts needed in asset renewal to balance the need to keep pace with recommendations identified in the ACA, while staying in step with the customer's top priorities of maintaining affordable cost of electricity and maintaining and upgrading equipment to ensure a safe and reliable electricity supply.

In 2023 and onwards, costs for material, labour, and equipment have increased. For example, the cost of pole replacements has increased by 60% due to material increases and use of vacuum excavation, and the costs of overhead and underground reactive replacements have increased by 50% due to material and transportation cost increases. While these unit costs have generally increased, the variance in the forecast average expenditure with the historical average is minimal.

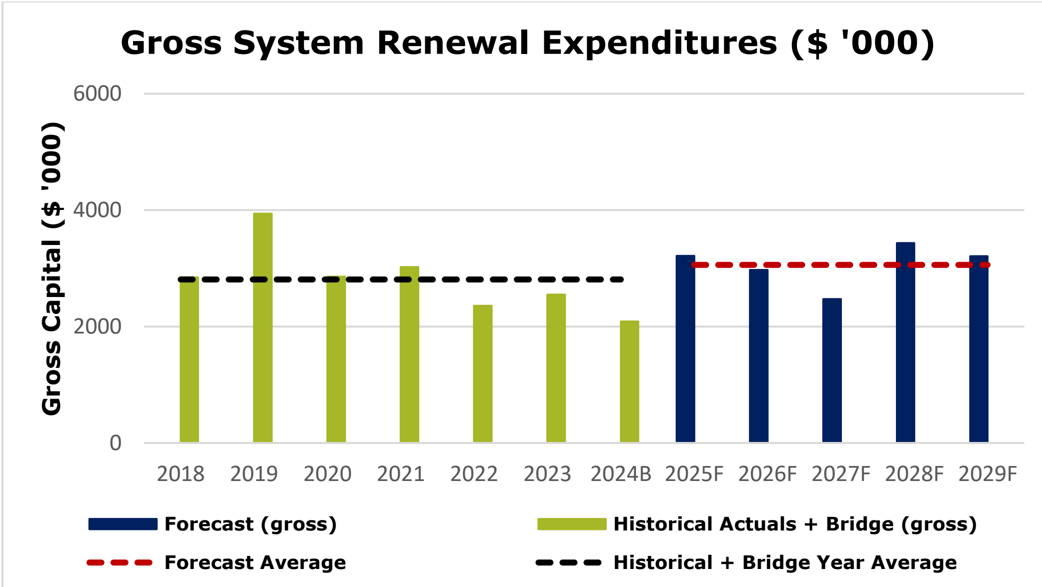


Figure 5.4-11: System Renewal Comparative Expenditures

5.4.1.3.4 System Service

The forecast average for System Service is 234% greater than the historical plus bridge year average, as shown in Figure 5.4-12. This is largely due to the beginning of the implementation of AMI 2.0. This will allow all communities to realize the benefits of this new system and improve the reliability of the metering network for EPLC. This is not expected to be an ongoing investment past the forecast period and metering costs in the future will reflect new and upgraded services.

In addition to the AMI 2.0 deployment project, various renewable expansion projects contribute to the increase in expenditures from the historical plus bridge year period to the forecast period, as well as material and labour cost increases.

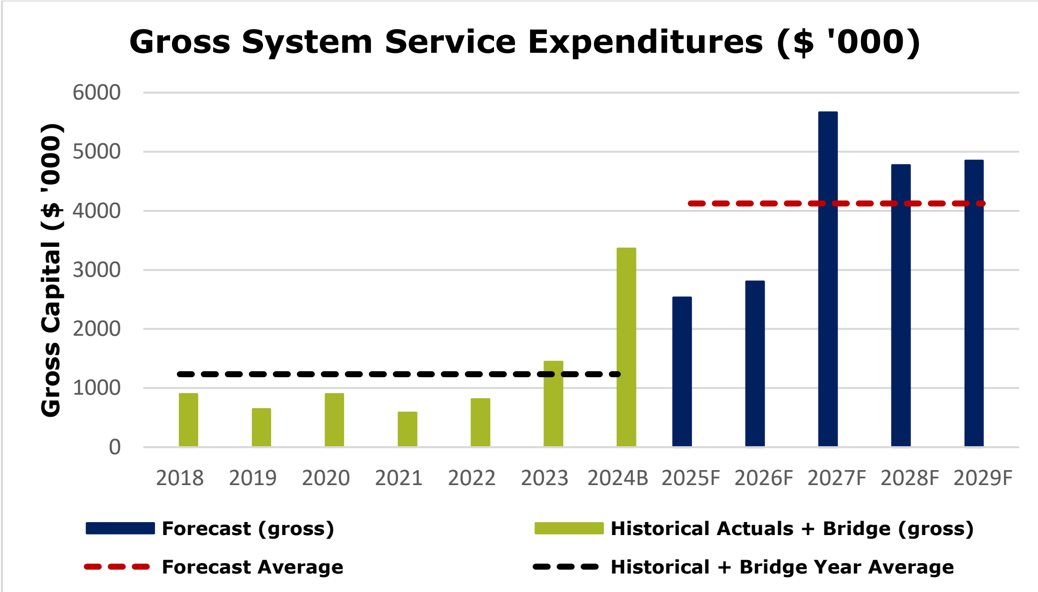


Figure 5.4-12: System Service Comparative Expenditures

5.4.1.3.5 General Plant

EPLC uses input from various sources, such as its ACA, third party reports, and vendor end-of-life notices to address critical issues needed within the General Plant program, including existing facilities, fleet, and IT assets. As shown in Figure 5.4-13, the forecast average is 48% greater than the historical plus bridge year average.

The forecast period focuses on investments in maintaining the state of EPLC’s buildings; improving the state of EPLC’s fleet through purchasing new vehicles and repairing or upgrading existing vehicles; replacing end-of-life hardware, including the upgrade of its server hardware to comply with OEB cyber security framework requirements; software upgrades, including CIS upgrades and enhancing the customer user experience; and digitalizing EPLC’s work centre.

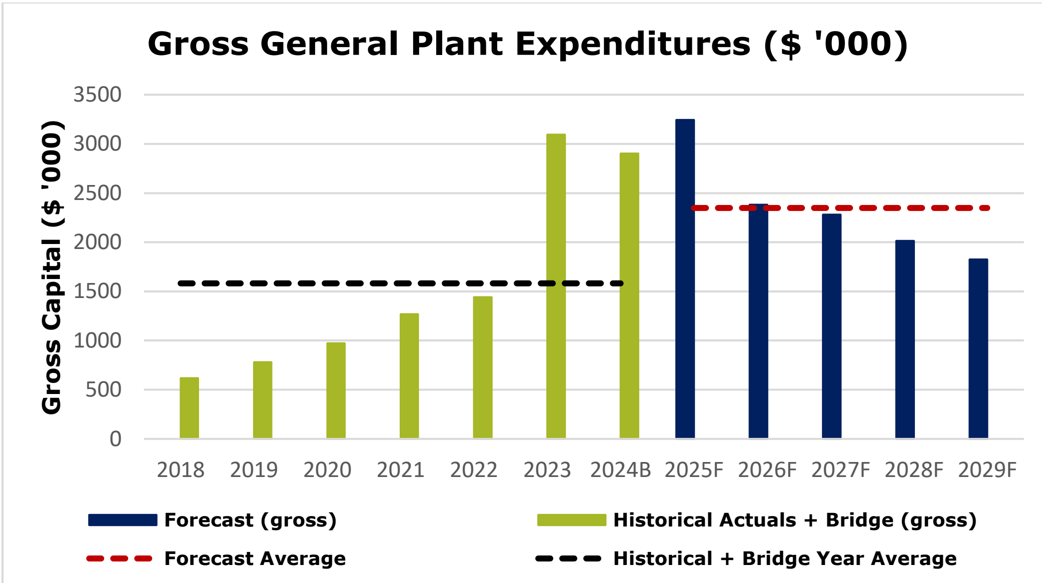


Figure 5.4-13: General Plant Comparative Expenditures

5.4.1.4 Important Modifications to Typical Capital Programs

EPLC strives to maintain a consistent and efficient capital program utilizing data from various sources to understand the condition of its assets. Historically, EPLC has used a TUL for single phase distribution Transformers of 45 years. Recently through conversations with transformer manufacturers, other similar sized LDC's, review of inspection data, asset conditions, and various unanticipated failures, EPLC has adjusted the transformer TUL from 45 to 40 years. This adjustment to TUL prompted a complete review of, and update to, our infrastructure replacement programs. The goal of this proactive approach is to reduce or eliminate unanticipated failures due to age and condition.

5.4.1.5 Forecast Impact of System Investments on System O&M Costs

Table 5.4-14 illustrates that EPLC's O&M costs are being maintained at current levels, with an increase mainly due to inflation and customer growth, for the forecast period. This is a result of EPLC's targeted capital investment plan.

When planning capital investments, there are both an increase and decrease in O&M over the forecast period. In some years, the O&M costs can increase due to ongoing maintenance of additional new assets in the field, but O&M costs can also decrease due to replacing problematic or end-of-life assets.

Due to high customer growth rates attributable to new development over the forecast period, EPLC's asset pool is expected to significantly increase in the near term, which will have an upward pressure on the system O&M. EPLC, like many other utilities, has experienced an increase in supply chain, contractors, and labour costs, which are contributing to an increase in System O&M costs. In addition, there is an industry-wide shortage of skilled labour, and technology advancements are demanding new skills from trades and technical staff. Further, EPLC is continuing to experience an aging workforce, which is contributing to an imbalance in its customer per employee ratio. As a result, EPLC has engaged in workforce planning to ensure required skills and talent are available to maintain and grow its distribution system and meet the changing demands of its customers over the next five years and beyond. Combining all these factors articulated above, EPLC's system O&M costs are anticipated to increase over the forecast period. However, EPLC's asset management plan mitigates some of these increases by replacing assets that have caused an increase to O&M in the historical period with newer assets that will require less ad-hoc O&M. As such, EPLC is expecting that the O&M costs remain consistent over the forecasted years, with some increase due to customer growth and inflation.

Table 5.4-15: Forecast System O&M Expenditures

Category	Forecast ($ '000)				
	2025	2026	2027	2028	2029
System O&M	3189	3235	3344	3245	3265

5.4.1.6 Non-Distribution Activities

There are no expenditures for non-distribution activities in EPLC's budget.

5.4.2 Justifying Capital Expenditures

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

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

1. Provide the proper allocation of investments to meet Health and Safety obligations, and ensuring work is executed in a way that positively impacts the general public, customers, and EPLC staff.

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

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

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

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

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

7. Modernization investments to enable EPLC in its effort to serve its customers better as it moves towards a DSO.

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

- Growth forecasts;
- Co-ordination with customers and third parties;
- Impact of regulatory initiatives;
- Historic system reliability;
- Asset condition forecasts; and
- Impact of CDM, REG, DER, and EV connections.

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

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

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

It is EPLC's goal to inspect, analyze, and plan all facets of the utility's operations in a holistic manner ensuring that all investments are optimized and coordinated to the fullest extent possible.

Customer Value

Delivering value to customers and other stakeholders is of critical importance to EPLC and is built into EPLC's foundational vision, which is "to provide the communities of Amherstburg, LaSalle, Leamington and Tecumseh with safe, reliable, and economical energy supply and service." EPLC's dynamic and progressive workforce commits to this vision by striving to be industry leaders in providing "best in class" solutions in the delivery of service to customers.

Meeting customers needs and expectations is reflected in EPLC's AM objectives of service quality and public safety. These key inputs and objectives drive EPLC's planning and AM processes, and customer feedback is a key input considered when developing capital plans.

By prioritizing system access projects, including residential expansions, service requests, and municipality driven projects, as mandatory, EPLC ensures that customer needs and requests are being met.

The scope of capital investments planned in the system renewal category has also been determined with the objective of optimizing the pacing of investments to strike a balance between affordable rate increases for customers while still investing in key areas to maintain the safety and reliability of the distribution system from deteriorating below an acceptable level.

The proposed system service investments deliver value to customers by accommodating expected load growth and improving grid operation performance and flexibility.

EPLC plans to begin to deploy AMI 2.0 over the forecast period and keep up with metering replacements, working towards a more automated network. Along these lines, EPLC will continue to implement a self healing grid as it works towards a smart grid. System service expenditures also include 200A network upgrades due to residential service upgrades and network capacity increase through the selling and purchasing of assets with HONI. These investments are targeted at reducing the size and duration of outages and improving response times.

EPLC's General Plant investments are also selected and prioritized such that they can continue to operate safely and efficiently and support other work. Recent and planned IT-related upgrades and digitalization efforts contribute to grid modernization. These upgrades will allow EPLC to make faster decisions to troubleshoot and respond to outages, provide more information and communication options to customers, and improve operational efficiencies by automating processes that were previously completed manually. Investments in EPLC's transportation and fleets will improve service quality for customers.

For the purpose of aligning EPLC's overall capital budget envelope with customer expectations, EPLC has prioritized and optimized its proposed capital investments such that the most critical projects and programs have been budgeted over the forecast, while a number of lower prioritized, less critical scoped projects and programs have been either deferred, reduced, or eliminated from the budget envelope.

The investments that EPLC has outlined above are aimed at meeting the top priorities of customers:

1. Ensuring reliable electrical service.
2. Delivering reasonable electricity distribution prices.
3. Replacing aging infrastructure that is beyond its useful life.
4. Investing in infrastructure and/or technology to better help withstand the impacts of adverse weather.
5. Helping customers reduce and better manage their electricity consumption.

Technological Changes and Innovation

With the emergence of changing policies, net zero targets, increasing prioritization of electrification, innovative technologies, and customer expectations, the distribution grid is quickly evolving from a system-centric, top-down, one-way power flow system to a customer centric, bi-directional power flow system. Customers now have the capability to generate their own electricity via Distributed Energy Resources (DERs), and as a result, distribution system planning and operations are becoming increasingly complex, and maintaining grid integrity is becoming more challenging. Practices which have historically been acceptable for the traditional grid need to evolve, and an improved and more modernized grid is required to accommodate this evolution.

As identified in EPLC's Strategic Plan, innovation is part of EPLC's corporate philosophy and is foundational to establish products and services that are valued by customers. EPLC monitors the state of technological advancements made within the utility sector.

Where it is financially responsible to do so, these technologies may be incorporated into the renewal and upgrade projects to meet the current and future needs of customers, improve operational effectiveness, and support the integration of renewables and smart grid technologies.

Examples of technological improvements and innovation either recently implemented or planned over the forecast period are noted below:

- **AMI 2.0** - EPLC plans to begin AMI 2.0 deployment within the forecast period. This will provide EPLC with more reliable communications for billing, infrastructure that will provide for current and future needs over the next 20 years, access to information such as enhanced power quality monitoring and grid edge computing for distributed intelligence, opportunities to better support the integration of renewables and EV's, as well as give customers better access to energy data and understanding their consumption.

- **Distribution Automation and Modernization -** EPLC plans to automate more of its network over the forecast period, which will also enable EPLC to expand it's self healing network, allowing the distribution system to automatically re-route power without manual intervention. This is a fundamental concept of a self-healing network, which helps to reduce the size and duration of outages.
- **Workflow Digitalization –** EPLC has begun the transition from paper-based workflow packages to a fully digital process where paper use is significantly reduced and, in some instances, eliminated. The vision for digitalization is to complete all work through modern technologies directly from the field and thereby eliminating paper job folders and manual work. The integration of data from multiple systems, embedding business processes, enabling intuitive workflows, regulatory reporting, and overall work management is fundamental in moving EPLC to the next level.

The above noted investments have and will continue to help prepare EPLC for the future role of LDC's in providing a high level of service and reliability for its customers and enabling its move towards becoming a DSO.

Consideration of Traditional Planning Needs

At a system level, organic load growth, EV adoption, electrification (fuel switching) and agricultural greenhouse expansion is anticipated to drive investments during the forecast period as constraints will begin to develop in almost every community EPLC services. Investments, such as access to additional supply and the potential build-out of new infrastructure, is needed to support large spot loads. EPLC is also investing in NWAs specifically associated with the transition toward a DSO. The PowerShare program will enable EPLC to reduce load or alternatively, add generation to specific locations within the distribution grid to alleviate these constraints as, or even before, they occur.

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

EPLC undertakes load studies to identify areas that may require investments to accommodate required capacity. Load growth and supply of power is a direct input into EPLC's planning for System Access and System Service type projects. It is also considered when rebuilds are completed to ensure that existing areas will be able to meet the existing and forecasted future demand needs for customers. Load growth is also a key input into the regional planning process which helps to identify future requirements (both wires and non-wires) to accommodate load growth.

Asset condition and reliability data are key inputs considered by EPLC when identifying, selecting, and prioritizing System Renewal expenditures. It is through the ACA and reliability studies that EPLC can identify the portion of the system that has reached (or soon will) a point that requires renewal, and where in the system those assets pose the greatest risk to reliability and/or public safety.

EPLC's challenge is to seek an optimized balance between cost, risk, and performance. Therefore, in preparing this DSP, EPLC has focused on prioritizing investments into renewal of the most critical infrastructure components to achieve the balance required between keeping the power supply reliability from degrading while maintaining the electricity distribution rates at affordable levels.

Overall Capital Expenditures

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

As detailed in Section 5.4.1.3, the overall increase relative to historical is driven by an increase in System Service to support an AMI 2.0 deployment and grid modernization, and an increase in General Plant to maintain and upgrade EPLC's fleet, IT, and buildings to continue serving EPLC's growing customer base.

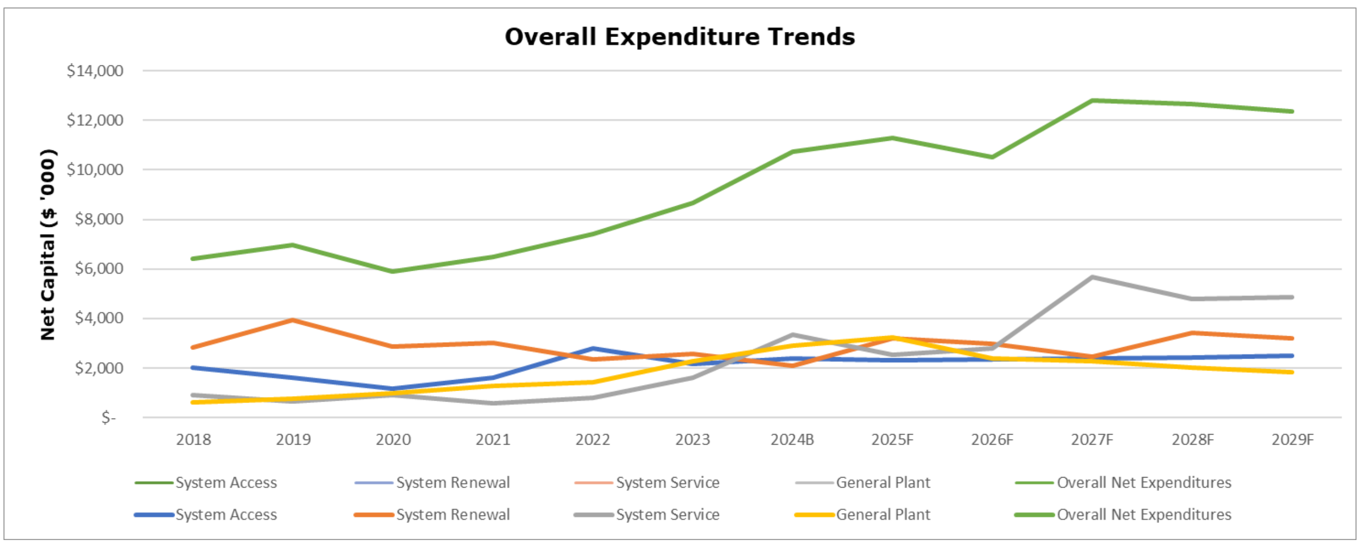


Figure 5.4-14: Overall Expenditure Trends

5.4.2.1 Material Investments

For this Application, EPLC's materiality threshold is $90,000. EPLC notes it has chosen to provide explanations for variances below its materiality threshold where these explanations were necessary for meaningful analysis. Using the prioritization process previously detailed in Section 5.3.1, EPLC has ranked and prioritized its material investments planned in the Test Year (2025). Table 5.4-15 presents the prioritized list of material projects and programs that have been budgeted in 2025 with their associated prioritization scores. The project prioritization criteria along with scoring to determine project priority rankings are shown in Table 5.4-15.

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

Table 5.4-16: Proposed Capital Investments during Test Year - Projects over Materiality

Category	Project Description	(Strategic Objective Score)	Relative Priority Rank	2025 Planned Expenditure ($ '000)
System Renewal	Pole Replacement Program	4.29	1	1,097
	OH and UG Reactive Replacements	N/A	N/A	257
	Infrastructure Rebuild Program (OH/UG)	2.92	4	1,789
System Service	Metering Replacement	N/A	N/A	395
	Self Healing Grid	3.41	2	1,300
	Conversion – 200A Network Upgrades	1.79	9	274
	DSO Activities	1.59	10	150
	Asset Purchase/Sell between EPLC and HONI	2.04	8	384
System Access	Subdivisions	N/A	N/A	1,080
	Residential Connections/Extension	N/A	N/A	573
	New service upgrades - C & I	N/A	N/A	448
	Municipal Requests	N/A	N/A	212
General Plant	Building Projects	2.89	5	630
	Transportation/Fleet	2.95	3	785
	Tools	2.32	6	100
	IT Hardware/Software	2.08	7	1,678
Gross Total Expenditure on Material Projects During Test Year				11,152
Gross Total Expenditure on Capital During Test Year (All Investment Categories)				11,303

APPENDIX A: MATERIAL INVESTMENT NARRATIVES

5.5 A. General Information on the Project/Program

1. Overview

This program entails general repairs, replacements, and upgrades within EPLC's facilities to facilitate the safe and efficient work of its personnel. Deferring investments in EPLC's facilities will have a detrimental impact on EPLC's operations that could affect both the safety of staff, as well as have an indirect impact on the reliability of the system and the ability to deliver services cost effectively.

Investments under this program vary year to year based on specific needs identified during the planning process. For the 2025-2029 period, anticipated costs are expected to total $2.38M. To help further inform and optimize EPLC's building investment plan, a third-party assessment is due to be carried out in 2025 to help inform refurbishments required for 2026 onwards. This assessment will be comparable to the Building Condition Report that was completed in November 2016 (Appendix G). In addition to the third-party 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 as Appendix F).
- Building upgrades based on inspection.
- Carry out a building envelope inspection.

Planned investments are in part due to the assessment that was completed in 2016. EPLC hired a third-party, ROA Studio Inc., to complete a Building Condition Report that provided observations and reported on the physical conditions of EPLC's building and property. The review addressed items that were significant for the continued operations of the facility in its current usage and occupancy, as well as made observations on the general physical condition of the subject property, material systems and components, and identified deficiencies and any unusual features or inadequacies. During the review, some of the building components at the time were considered in "Fair" condition. According to the report, a "Fair" assessment indicated that the component or equipment would probably require repair or replacement anytime within five years. A list of items deemed in "Fair" condition are listed below:

Subject	Category	Condition
Site	Building System	Fair
Roofing | Skylight	Building System	Fair
HVAC	Building System	Fair
Masonry Block	Building Exterior	Fair
Pre-fin Metal Siding	Building Exterior	Fair
Over Head Door & Frames	Windows/ Exterior Doors	Fair
Sealants/ caulking	Windows/ Exterior Doors	Fair
Mod-Bit Roof	Roofing/ Skylights	Fair
Skylights	Roofing/ Skylights	Fair
Ceilings	Interior Finishes	Fair
Masonry	Structural Elements	Fair
Misc. Metals	Structural Elements	Fair

Rooftop Units	Heating, Ventilating and Air Conditioning	Fair

As such, EPLC was prudent in monitoring building components that were assessed as "Fair" and ensuring replacements were made where feasible and appropriate. Items that were not replaced or repaired within the five-year period 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.

Planned investments for the 2025-2029 forecasted period are as follows:

Building & Fixtures	($)				
	2025	2026	2027	2028	2029
HVAC Replacements & Balancing	130,000				
Roof Rehabilitation	170,000				
Building Upgrades Based on Inspection	330,000	150,000			
Additional Fleet Garage		272,500	300,000		
Parking lot Sealing/Painting		50,000			
Gate and Fencing Replace/Repair			100,000		
EV Charging Infrastructure			100,000		
Rear Yard Sump Replacement				150,000	
Storage Yard Expansion (South)				250,000	
Damaged/Leaking Tx Area Upgrade				125,000	
East Mezzanine Renovation					100,000
Employee Exterior Sitting Area					75,000
Garage Door Replacements					125,000
Rear Yard Sump Replacement					76,250
Pavement Extension (rear)					175,000

Planned spend in the 2025-2026 period is based on prior inspections, including the 2016 Building Condition Assessment and the 2022 Roof Condition Report, as well as internal assessment based on historical spend of projects with similar caliber. With this data, EPLC was able to formulate and provide the best estimate at this time. Future projects will further be distinguished, refined, and accounted for based on the 2025 Building Condition assessment.

2. TIMING

i. Start Date: 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: The below listed factors can impact the timing of the proposed investments:
- Resource constraints;
- Supply chain issues;
- Third-party contractors;
- Project prioritization; and
- Overall budget constraints.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	75	178	33	280	226	730	735	630	473	500	525	551
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	75	178	33	280	226	730	735	630	473	500	525	551

4. ECONOMIC EVALUATION (EXPANSION PROJECTS)

This is not applicable.

5. COMPARATIVE HISTORICAL EXPENDITURE

Historical costs have varied year over year in accordance with specific needs identified and works undertaken. Due to the nature of the projects within this program and the fact that works are completed on an as-needed basis depending on the need, there are no good cost comparators available, and a comparison of historical projects and future projects is not indicative of any particular trend.

6. Investment Priority

This investment is of relatively lower priority, with minimal direct impact on customer outages and service levels compared to other projects. While a lack of investment in buildings and fixtures does not pose an immediate material safety risk, prolonged inaction could detrimentally affect EPL's operations. This impact extends to staff safety, system reliability, and the effective delivery of services. Postponing the investment may lead to more costly remedial solutions in the long term.

Out of eleven (11) material projects/programs planned and prioritized an optimized through EPLC's process, this program was ranked 11th based on its Risk/Strategic Objective Score, as shown in Table 5.4-15 of EPLC's DSP.

7. Alternatives Analysis

The following options have been considered by EPLC:

i. **Do nothing:** Doing nothing is not a viable option. Without investing in the ongoing repair, replacement, and upgrades of EPLC's building and yard facilities, there is a risk that these facilities will not be fit for EPLC staff to carry out their jobs safely and efficiently. Additionally, more costs will be incurred due to increased maintenance of existing building components in comparison to replacing components with sufficient upgrades.

ii. **Carry out the proposed pacing of investments:** This is the preferred option as it allows EPLC to continue to support its operations. EPLC evaluates the identified needs to determine which are most critical to undertake and which can be monitored and pushed out to later years. Project-specific alternatives (e.g., run to fail vs. repair vs. replace like-for-like vs. upgrade with additional functionality) are considered on a case-by-case basis depending on the identified need.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.5 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Investments in buildings and fixtures ensures that EPL's facilities remain modern, clean, safe, and secure. These investments will foster a conducive

	environment for its staff that improves operational efficiency.
Customer Value	A modern, clean, and safe environment ensures that staff can undertake their work effectively and efficiently address the needs of EPL's customers.
Reliability	Through these investments, there is no direct impact on reliability of the network in terms of planned outages. However, these facilities are crucial to support continued EPL's operations. These facilities house equipment and materials that are used to help maintain the reliability of the system.
Safety	Addressing damaged, obsolete, or end-of-life building assets through repair, replacement, and upgrades is crucial in averting failures that could jeopardize employee and public safety. This initiative guarantees EPL a secure workspace with functional building assets compliant with the latest health and safety standards, ensuring the well-being of staff during work activities.

2. Investment Need

i. Main Driver*:* Non-System Physical Plant - The primary driver for this program is to renew and invest in EPLC's non-system physical plant. Within the context of this program, it is to invest in EPL's facilities that house in-office & operations staff and equipment that is used for maintenance and operations.

ii. Secondary Drivers: System Maintenance Support – EPLC's facilities also house maintenance equipment and vehicles. By investing in these facilities and ensuring they are fit for purpose, EPL is protecting the equipment stored which helps to ensure that they will work when needed.

iii. Information Used to Justify the Investment: EPLC monitors its building assets, such as plumbing, air systems, garage doors, windows, security systems, gates, generators, and heating/cooling, using preventative inspections and maintenance. This process identifies and prioritizes necessary repairs, replacements, and upgrades over the planning horizon. The derived insights aid in the overall upkeep of existing buildings, enhancing safety, accommodating growth, and optimizing operational efficiency. In addition, EPLC had a third-party assessment performed on its roof in 2022 that has informed its rehabilitation. EPLC has also planned other building inspections in the forecast period that will further inform and refine its building investments.'

In 2016, EPLC had a third-party assessment of its building condition completed, which included a list of building deficiencies that would need replacement either immediately or within five to 10 years. EPLC used that assessment to determine which building components were considered in "fair" or "poor" condition and made prudent investments in its buildings to replace those items. Components and equipment marked as "fair" indicated that replacement would be probable within a five-year period. EPLC continued to monitor the components in question and where feasible and necessary, made investments to replace. Items that were not replaced within the five-year period were included in the 2025-2029 forecasted budget, as they are likely in need to be replaced. EPLC plans to have a third-party complete another building assessment to determine what other components and equipment should be considered in the next five to 10 years.

For instance, the 2016 Building Condition Report determined that EPLC's HVAC units were potentially in need of replacement within a five-year period. EPLC monitored its HVAC units and replaced one of its units within the 2017-2022 period. Other HVAC units were continually monitored and reviewed by internal and external resources, until replacement was determined essential. As such, EPLC has replaced one of its HVAC units in 2023 and has sought quotes for additional HVAC unit replacements with similar year/model for the 2025 year.

EPLC is planning to complete another third-party assessment on its building condition to determine other significant projects that need to be undertaken in the 2025-2029 period. From internal reviews and based on previous reports, EPLC has noted that window replacements will need to be completed, as significant air penetration through windows and wall areas has been detected within its building. In addition to window replacements and of similar note, EPLC plans to increase overall R-value of its building by adding insulation into its wall cavities where necessary. Lastly, it was determined that the building façade on the rear end of the building is dated and showing signs of wear. While EPLC investigates the addition of insulation, this would be an opportune time to replace the façade, as work will already be considered for that area of the building and it would drive down costs of having additional third-parties come at separate times to re-work on the same area. This plan will be refined further depending on the outputs of the 2025 updated building assessment.

In 2022, EPLC hired a third-party, Empire Roofing Corporation, to complete an assessment of its roof at its Highway #3 location. The focus of the report was to determine the life expectancy of the existing roof and whether replacement was determined to be needed. The results of the report revealed that while the roof is still protecting the building, it has exceeded its life expectancy. Severe cracking and "alligatoring" of the roof membrane due to age and weathering was noticed, as well as improper pitch pockets on the roof were detected and protrusions were beginning to delaminate at the seams. It was therefore recommended that a recover be completed. Details of the report can be found in Appendix F.

EPLC started building renovations in 2023, with some carryover work and projects in the 2024 year. These renovations include upgrades to work areas which make the building safer and more efficient for Essex Powerlines' employees. Some upgrades to the building have been planned for 2024, including but not limited to: updating the employee common area, installing an acoustic ceiling in the CSR department to reduce unwanted noise and create job site efficiencies for the department, renovations and upgrades to the hallway area as well as some office space that were demonstrating wear, and purchasing a building generator to ensure operations at the work site can remain optimal and safe for employees during longer duration outages. Additionally, in the 2026 year, it is recommended that EPLC review the parking lot at its building as per the 2016 Building Condition Report assessment. The 2016 assessment recommended that all asphalt pavement be removed inclusive of the granular layer and reconstructed to ensure maximum design life, as well as to review the storm water management strategy. EPLC will complete additional analysis as necessary and plans to update its parking lot in the forecasted period based on updated analysis.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice*:* The proposed investments work to ensure that EPL can deliver safe, reliable, and efficient services. It is accepted industry practice that utilities have office space for staff to perform their functions, such as engineering and accounting, to effectively meet their customers' needs. Additionally, it is important that field staff are provided with the resources, tools, equipment, and workspace to conduct maintenance and capital projects. It is good practice for utilities to allocate funds for maintaining operational buildings, yards, and storage areas. EPLC, having assessed its requirements, has strategically planned its projects to protect its operations and maintain the delivery of safe, reliable, and efficient services to its customers.

ii. Cost-Benefit Analysis: For any service required without a contract, EPLC evaluates several quotes to ensure the best value is obtained in terms of cost and delivery time. Project-specific alternatives are also evaluated on a case-by-case basis depending on the identified need, and cost analysis is considered following EPLC's corporate purchasing policies.

iii. Historical Investments & Outcomes Observed: Historical investments in buildings and fixtures have supported EPLC's operations and have enabled field crews to carry-out maintenance activities in a safe, efficient, and cost-effective manner. Historical investments in this program have resulted in the ability of EPLC staff to continue to perform all its critical services, as well as investing in the upkeep of the building, and addressing health and safety defects that were identified. This has ensured EPLC's continued ability to operate and deliver safe and reliable electricity supply to its customers.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

This is not applicable.

5. INNOVATION

This is not applicable.

5.6 A. General Information on the Project/Program

1. Overview

This program outlines the investments EPLC is proposing to address its IT hardware and software needs. Modern IT infrastructure is a critical component of EPLC's operations needed to ensure security, resiliency, and effectiveness. Through the planning horizon, EPLC is looking 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. Investments include acquisitions such as computers, monitors, and related equipment for its personnel, ongoing hardware and software maintenance, and defending against cyber security threats.

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, such as EPLC, persistently face challenges of delivering secure, timely, and technologically advanced solutions within an increasingly complex IT landscape. As EPLC continues to future proof its operations, IT related infrastructure is imperative to meet the requirements of ensuring security and integrity of its data and infrastructure while also enhancing business efficiencies, automations, and customer experience.

The capital forecasts for these investments include the replacement of existing IT hardware and software, as well as new investments in technologies that support the goals of the organization. EPLC's IT hardware and software plan focuses on replacing end-of-service life assets and ensuring reliable and secure infrastructure. As such, deferring investment in IT infrastructure will have a negative impact on EPLC's ability to meet the needs of its customers and conduct its 24/7 operations and may lead to more costly remedial solutions.

The following are a sample of some of the major investments EPLC plans to undertake in the forecast period:

- 2024/25- 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.
- 2026- GIS Utility Network Design upgrade/replacement – EPLC's current GIS model is nearing end-of-life as per the third-party/vendor assessment. Upgrades are critical to utility operations.
- 2026- 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.
- 2028- Website improvements- EPLC plans to improve its website to enable better customer experience and maintain security requirements.
- 2024- 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 operations risk, these upgrades are necessary.
- 2024- Internet upgrade- EPLC is exploring redundant internet supply to strengthen business continuity.
- 2026- Asset Management & AI- EPLC plans to invest in its asset lifecycle management and security requirements for software upgrades

- 2027- GP Accounting Software Replacement- EPLC's current accounting software is at its end-of-life and will no longer be supported by third party vendor. As such, replacement is necessary for continued operation of EPLC.
- 2025-2029- 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 under this program vary year-to-year based on specific needs identified during the planning process. For the 2025-2029 period, EPLC will incur $1.19M in hardware investments and $3.24M in software investments, as shown below:

Computer Software	($)				
	2025	2026	2027	2028	2029
General Software	74,857	76,354	77,881	79,439	81,028
CIS Upgrade	908,979				
UtiliDE Map Interface	58,816				
GIS Utility Network Design		331,510			
OMS & SCADA Enhancements		133,673		160,408	
Asset Management Deployment/Enhancements		133,673			133,673
AI Pilot Deployment		80,204			
GP Upgrade/Replacement			641,632		
Website Customer Experience				160,408	
Real Time DSP 2.0					106,939

2. Timing

iv. Start Date: January 2025

v. In-Service Date: January 2025- December 2029

vi. Key factors that may affect timing: The below listed factors can impact the timing of the proposed investments:

- Resource constraints;
- Supply chain issues;
- Project prioritization; and
- Overall budget constraints.

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	278	374	371	366	555	1,509	**1,069**	**1,678**	971	833	553	390
Contributions	0	0	0	0	0	0	**0**	**0**	**0**	**0**	**0**	**0**
Capital (Net)	278	374	371	366	555	1,509	**1,069**	**1,678**	971	833	553	390

3. Historical and Future Capital Expenditures

4. Economic Evaluation (Expansion Projects)

Economic evaluation is not applicable.

5. Comparative Historical Expenditure

Historical costs have varied year over year in accordance with specific needs identified and works undertaken. Capital purchases are influenced by ongoing business requirements, supporting new and evolving software applications, ensuring network and data security, and managing risk. Due to the nature of the projects within this program and the fact that work is completed on an as-needed basis, there are no good cost comparators available, and a comparison of historical projects and future projects is not indicative of any particular trend.

6. Investment Priority

This investment is of relatively lower priority, ranking 7th out of eleven (11) material projects/programs planned, prioritized, and optimized through EPLC's asset management process, as shown in Table 5.4-15 of EPLC's DSP. The investment has a strategic objective score of 2.08 when compared to other programs because of its minimal direct impact on customer outages and service levels compared to other projects. While a lack of investment in IT infrastructure does not pose a direct material safety risk, prolonged inaction could detrimentally affect EPLC's operations. This impact extends to system reliability and the effective delivery of services. EPLC's approach has always been to ensure its technology is current and effective in providing reliable, secure, and accountable hardware and software for the benefit of the organization and its customers. As such, postponing the investment may lead to more costly remedial solutions in the long term.

EPLC closely monitors its IT asset management program to ensure hardware and software infrastructure is not neglected and remains stable. The following needs were identified and assessed when scoring the project:

- **Regulatory/Legal Compliance-** Compliance with the OEB Cybersecurity Framework
- **Company Image-** De-risking EPLC from cybersecurity threats and keeping customer information protected through increased privacy protection.
- **Financial Impact-** Assessing system upgrades and maintenance costs through cost-benefit analysis. Minimizing costs where possible by maintaining safe and reliable IT services and infrastructure.

7. ALTERNATIVES ANALYSIS

i. Do nothing: Inaction is not a viable option. Without ongoing investments into IT hardware and software, there is a risk that existing infrastructure will not be fit for EPLC's operations as it continues to grow. Additionally, many of the systems will become unsupported by the vendor/supplier if no action was taken. This would be cost prohibitive and would also pose intolerable risk to customer service.

ii. Replace like-for-like or with limited features: This would result in loss of functionality and inhibit EPLC from realizing its goals and objectives of meeting customer expectations and enabling energy transformation initiatives. Additionally, work activities may be limited resulting in loss of productivity. Moreover, replacing like-for-like would be cost prohibitive as current systems are not supported on existing hardware, resulting in more maintenance and upkeep costs. Overall, this is not feasible and would pose intolerable risk to EPLC operations.

iii. Carry out the proposed pacing of investments: This is the preferred option as it allows EPLC to continue to support its operations. EPLC evaluates the identified needs to determine which are most critical to undertake and which can be monitored and pushed out to later years. Project-specific alternatives are considered on a case-by-case basis depending on the identified need.

8. INNOVATIVE NATURE OF THE PROJECT

This is not applicable for the nature of this project.

9. LEAVE TO CONSTRUCT APPROVAL

This is not applicable for the nature of this project.

5.7 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Investing in cutting-edge IT hardware and software allows for streamlined processes and automation, significantly boosting operational efficiency. With advanced tools and systems in place, tasks that once consumed time can be executed swiftly and accurately. This efficiency translates to increased productivity, reduced manual errors, and ultimately, cost savings.
Customer Value	IT hardware and software investments contribute directly to enhancing customer value by enabling personalized and seamless experiences. Customer relationship management (CRM) systems, data analytics, and user-friendly interfaces empower businesses to understand and cater to individual customer needs more effectively. This not only fosters customer satisfaction but also builds long-term loyalty.
Reliability	The reliability of EPLC's business operations relies heavily on the robustness of its IT infrastructure. Investing in reliable IT hardware and software ensures consistent performance and minimizes the risk of downtime. Robust systems contribute to the overall stability of operations, fostering a dependable environment for both internal processes and external interactions.
Safety	Investments in hardware and software improves safety. These investments enable the removal of aging or damaged hardware that could cause injury, and investments in software enable communications that can expediently relay real-time safety information to relevant parties.

2. Investment Need

i. Main Driver*:* Non-System Physical Plant & Business operations efficiency – The primary driver for this program is to renew and invest in EPLC's non-system physical plant due to asset retirement and to achieve operational efficiency. Within the context of this program, it is to invest in IT hardware and software that empower EPLC to conduct its 24/7 operations effectively and efficiently.

ii. Secondary Drivers: Cyber Security – Investments in IT infrastructure ensure the safety of sensitive data and protect against cyber threats. Robust firewalls, encryption protocols, and regular security updates safeguard the organization's digital assets and maintain the integrity and confidentiality of EPLC and its customers' information.

iii. Information Used to Justify the Investment: EPLC continuously monitors the condition and effectiveness of its IT infrastructure and receives notice from vendors and third-party assessments when assets are nearing end-of-life and end-of-support. This process identifies and prioritizes necessary repairs, replacements, and upgrades over the planning horizon. The derived insights aid in the overall upkeep of hardware and software to reduce costs and improve operational efficiency in the long-term. Once assets are deemed end-of-life and replacement is required or necessary, EPLC starts its procurement process by retrieving quotes from multiple vendors prior to purchase to ensure value is being obtained.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice*:* The proposed investments are designed to fortify EPLC's capacity to deliver secure, dependable, and efficient services. It is recognized that utilities depend upon modern IT infrastructure to fulfill their essential functions. With cybersecurity threats continuously evolving, hardware and software must be robust and up to date to protect the integrity of EPLC's operations and safeguard its customers data. EPLC, following a thorough assessment of its needs, has strategically planned these projects to safeguard operations and uphold the provision of secure, reliable, and efficient services to its customers.

ii. Cost-Benefit Analysis: As with its other initiatives, EPLC rigorously assesses multiple quotes when undertaking hardware or software projects, emphasizing both cost-effectiveness and timely delivery. Project-specific alternatives are individually scrutinized, aligning with identified requirements, and subjected to cost analysis. This meticulous approach ensures optimal value acquisition in the realm of IT maintenance and services.

iii. Historical Investments & Outcomes Observed: Past investments in IT hardware and software at EPLC have been pivotal in sustaining operational excellence. These investments have empowered staff to conduct their activities securely, efficiently, and with cost-effectiveness. The historical commitment to this program has equipped EPLC staff to seamlessly deliver critical services but has also facilitated ongoing maintenance of its digital infrastructure.

iv. Substantially Exceeding Materiality Threshold:

EPLC relies on a diverse set of technology hardware and software to support its business goals, maintain operational efficiencies, meet the needs of customers, and stay compliant with regulatory requirements. EPLC plans its capital expenditures for technology to ensure its infrastructure is robust, current, and adaptive, leading to a secure and efficient environment. Capital expenditures are also influenced by ongoing business requirements, supporting new technology that will enable grid modernization, ensuring data integrity and security, as well as managing overall risk. To maintain a secure environment and enable privacy protection, EPLC has historically hosted systems on its own servers as opposed to an on-demand cloud computing platform, such as Amazon Web Services. In 2017, new applications were moved over to in-house servers to create efficiencies and reduce clutter within EPLC's IT system. This move also de-risked EPLC from cybersecurity threats, as critical information to the company was hosted locally in-house and physically behind a firewall for an extra level of security. In addition, many of the solutions that are offered as online versions are off-the-shelf products that are not compliant or compatible with other programs and solutions. EPLC has historically chosen in-house solutions to be able to integrate multiple platforms through dependencies and realize automation capabilities through technological convergence. The ability to have in-house systems has helped EPLC achieve operational efficiencies, provided privacy protection for company and customer information, and de-risked EPLC from cybersecurity vulnerabilities.

EPLC reviews its applications on a continuous basis and uses a third-party IT consultant, Netmon, to provide analysis on technical and financial feasibility to move from in-house servers to external servers and applications where it makes sense.

Capital projects are divided into hardware and software components, as depicted below:

Hardware & Software Upgrades

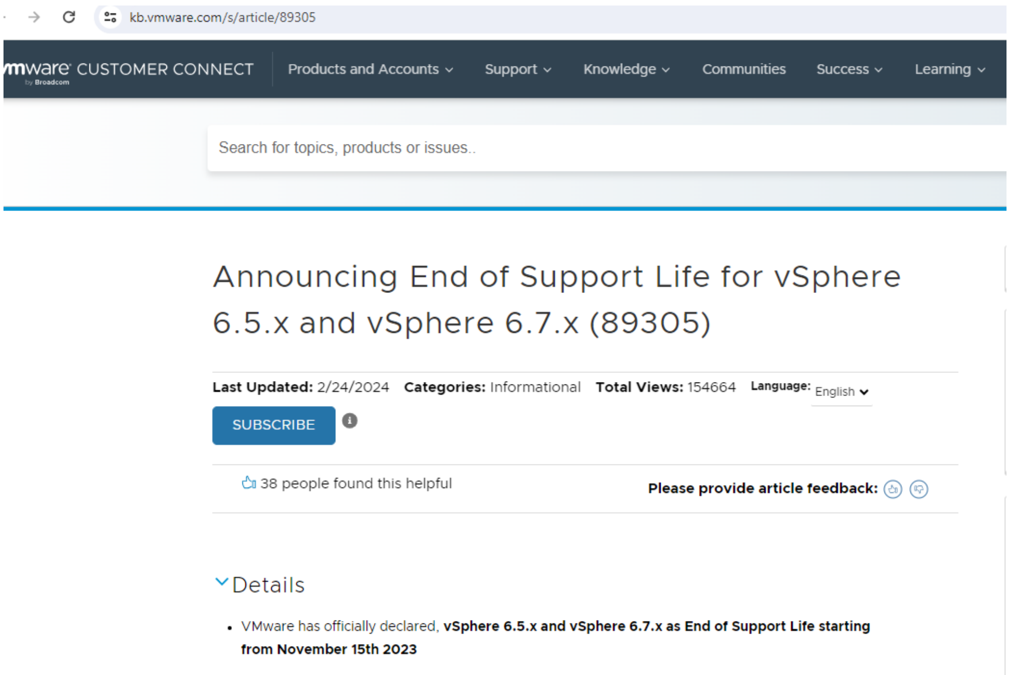
New hardware equipment and software will be acquired in the forecasted period for various reasons, including, but not limited to, reaching end of service life of existing software, warranty and support expiry, increased cybersecurity risk, and maintaining customer and business data integrity and security.

	Category	**Dependency**	**Upgrade Reason**
Virtualization Operating System (VMWare)	Operating System	Server Hardware	Cybersecurity Compliance
Dell Host Servers and SANs (production environment- primary server room)	Hardware	N/A	Risk of Operation
Windows Operating Systems	Operating System	Virtual Operating System	Cybersecurity Compliance

EPLC's Virtualization Operating System (VMware) is at its end of life and end of support. As such, no security patching and firmware will be provided to the existing version of VMware that is installed on the Host Server. This puts EPLC at increased cybersecurity risk and would not meet compliance requirements for the OEB Cybersecurity Framework. This project is therefore critical to EPLC operations and must be upgraded to ensure compliance and de-risk EPLC.

In addition, the newer version of VMWare that is being sought is not currently supported on existing hardware. As a result, EPLC's server hardware must be upgraded to host the newer, more secure VMware. EPLC currently uses Dell Host Servers and SANs for its production environment and primary server room. The age of this equipment will exceed all warranty levels and support in 2024. More specifically, this includes the primary 5-year MFG warranty, as well as the additional third-party extended warranty EPLC purchased to reach 2024. This puts EPLC at risk for maintaining the integrity of both business and customer data that resides on that server. Moreover, as of 2024, the host servers and SANs have reached its typical useful life of 7 years old. According to manufacturers and industry average, the recommended lifecycle of Server Hardware is 5-7 years. EPLC has exhausted the use of its servers, and if not replaced, will have an increased risk of its operation and efficiency, as well as increased maintenance costs. As a result, it is highly recommended that EPLC replace its servers and SANs in 2024. Figure 1 below is a screenshot from the VMWare website indicating end of support life for the current version that EPLC operates.

Figure 1- VMWARE End-of-Life Support



Lastly, EPLC currently uses Windows Operating Systems. As Windows is upgrading its OS, the newer instances of Windows Server will not be supported on EPLC's current running VMWare. This poses a cybersecurity risk and compliance risk with the OEB Cybersecurity Framework. As such, it has been recommended by third-party consultants to upgrade EPLC's existing Operating System.

	Category	**Upgrade Reason**
CIS Billing Software	Billing System	Risk of Operation; Increased Expenses; Inadequate for meeting customer expectations and needs
GIS Software	Utility Operations	Risk of Operation; End-of-Life Support
Accounting Software	Accounting System	Risk Operation; End-of-Life Support

EPLC plans to upgrade its CIS billing platform in 2025. The existing billing platform has proven to be costly for supporting other systems and building tie-ins and integrations into EPLC's other software tools, causing inefficiencies in EPLC's operational performance. EPLC believes that the next generation of CIS needed will empower customers to make choices as it relates to electrification and conservation and will enable customers through extensive data, provide engaging tools at their fingertips, and allowing EPLC to operate effectively and efficiently while providing best-in-class service to its customers. As such, 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 with a user-friendly and connective customer platform, and allowing for tailored communications and engagement to customers via preferred channels.

EPLC started its procurement process for a new CIS platform that matches the future needs of its customers and grid modernization plans and produced the following potential solutions:

(1) **Remain with existing CIS billing vendor and upgrade to its newest version**. While this solution would be economically viable for EPLC and its customers, it will not meet the future needs of grid modernization and customer expectations. EPLC continues to work towards modernizing its grid operations by deploying projects such as its Self-Healing Grid plan and DSO Pilot project. To support these projects and the future remodelling of a utility, LDCs need to invest in innovative CIS billing platforms that enable consumer choice and allow for greater customer connection. Aside from enabling grid modernization efforts, an advanced CIS platform is necessary to meet the needs of consumers. According to a 2021 McKinsey & Company report, consumers expect personalization from businesses they interact with. This has been evidenced through consumers becoming more aware and knowledgeable on industry trends and requiring more interaction from EPLC employees. As such, EPLC remains vigilant in offering solutions to customers that enhance engagement and promote customer choice, where reasonable and acceptable. Simply remaining with the existing CIS solution will postpone grid innovation plans and defer EPLC's commitment to providing a robust customer-centric experience to its customers.

(2) **Replace existing CIS platform with a new system that provides more enhanced features and functionalities**. EPLC has initiated a procurement process to determine what viable options are available for a new, robust CIS billing platform. The proposed CIS billing system will meet the needs of customers, increase operational performance, and have increased functionality by integrating with other software systems. As such, EPLC has obtained two separate quotes from reputable companies that offer a cloud-based CIS platform. Both companies provide a platform that maintains security compliance, enables data access for reporting metrics, and a complete customer care and billing platform. While both companies had exceptional offerings, EPLC plans to further pursue the CIS platform that has additional features for customers and a more comprehensive back-end for its workers. Overall, both platforms consist of a one-time implementation cost of approximately $700,000 to $1,100,000, which includes full integration with the Ontario provincial MDMr for meter synchronization and all aspects of billing quantity requests, responses, data editing, and other requisite data flows. While costly, the new solution has increased functionality in comparison to existing solutions, as it collapses the stack of customer-facing products EPLC currently uses into a single unified system. This one-time

implementation cost also includes the set up of a customer portal and mobile app, which is part of EPLC's customer service enhancement roadmap.
In addition, EPLC is seeking to reduce costs of a new CIS solution by reaching economies of scale with other utilities. As part of its procurement process, EPLC has partnered with three other utilities who wish to upgrade their CIS platforms to offer enhanced solutions to their customers. EPLC is currently in negotiations with potential vendors to drive costs down and maintain reasonable annual costs in line with existing spend.

Below are the two quotes that have been provided by interested vendors:

Figure 2- CIS Quotes

Pricing Summary

SpryPoint

Essex Powerlines

	Annual Cost	Implementation Cost	Solution Cost
SpryCIS	$ 210,000	$ 923,120	$ 1,133,120
SpryMobile	$ 14,760	$ 61,600	$ 76,360
SpryEngage	$ 40,000	$ 73,920	$ 113,920
SpryIDM	$ 16,000		$ 16,000
Total	**$ 280,760**	**$ 1,058,640**	**$ 1,339,400**

Optional Software

Notes
All SpryPoint solutions are delivered in the cloud and little to no hardware is required.
SpryCIS is priced at $5.00/Active Account/Year for Electric.
SpryCIS is priced at $2.50/Active Account/Year for Water.
SpryMobile includes 6 Full Users @ $125/user/month and 8 Light Users @ $60/user/month
SpryEngage is optional and priced at $1.25/Active Account/Year.
SpryIDM is optional and priced at $0.50/Active Account/Year.
SpryIDM will be required for the storage and presentation of interval data in SpryCIS & SpryEngage.
SMS Pricing - Inbound & Outbound is $.02 per message
IVR - Outbound Voice Messaging is billed at $.03 per minute
SMS Pricing – Optional Short-Code is $15,000/Year.
Pricing does not include any applicable taxes.
Travel Costs are estimated at $50,000

Proposal to Essex Powerline Corp.
09/11/2023

Proposed **Pricing**

The below pricing is based on a SaaS deployment that Includes:

- Issue / Operations / Update Services
- Security & Monitoring Services
- Infrastructure & Technical Services
- All required Software environments
- SLAs across all service
- Initial implementation

Pricing Table (for budgetary purposes)

Standard SaaS Implementation	*$700,000
Annual SaaS Fee 53k account (33k electric, 20k water) *$0.29*12	**$184,400
Initial Term	5 Years

*Optional services as outlined in itemized list of deliverables not included in standard implementation price. Required integrations needs to be discussed and finalized.

**Annual SaaS fee is inclusive of the services outlined in this proposal.

Overall, while a CIS upgrade is costly, it provides an opportunity to realize grid modernization benefits for both the utility and its customers by promoting increased functionality and data enhancements. The evolution of the CIS platform will ultimately enable consumer choice and exceed customer expectations, while providing operational benefits to EPLC employees.

In 2026, EPLC will be upgrading its GIS system from the existing ESRI ArcMap to the utility network model. The existing GIS system provided by ESRI will no longer be supported, with version 10.8.2 being retired in March 2026. The existing version entered mature support in March 2024, meaning the vendor will no longer provide functionality-based patches or hotfixes. While security vulnerabilities will be assessed by the vendor (if applicable), EPLC is required to maintain the software until the replacement is made. EPLC plans to switch to the Utility Network Model, as it is the next logical step for EPLC's operations. The Utility Network Model provides a services-based architecture using ArcGIS Enterprise, enabling large-scale, multi-user deployments and full network display. This includes web maps and apps, which will further be utilized on EPLC's website for outage information for customers. After much analysis, EPLC concluded that the Utility Network Model was the most feasible option in terms of cost-effectiveness and operational value.

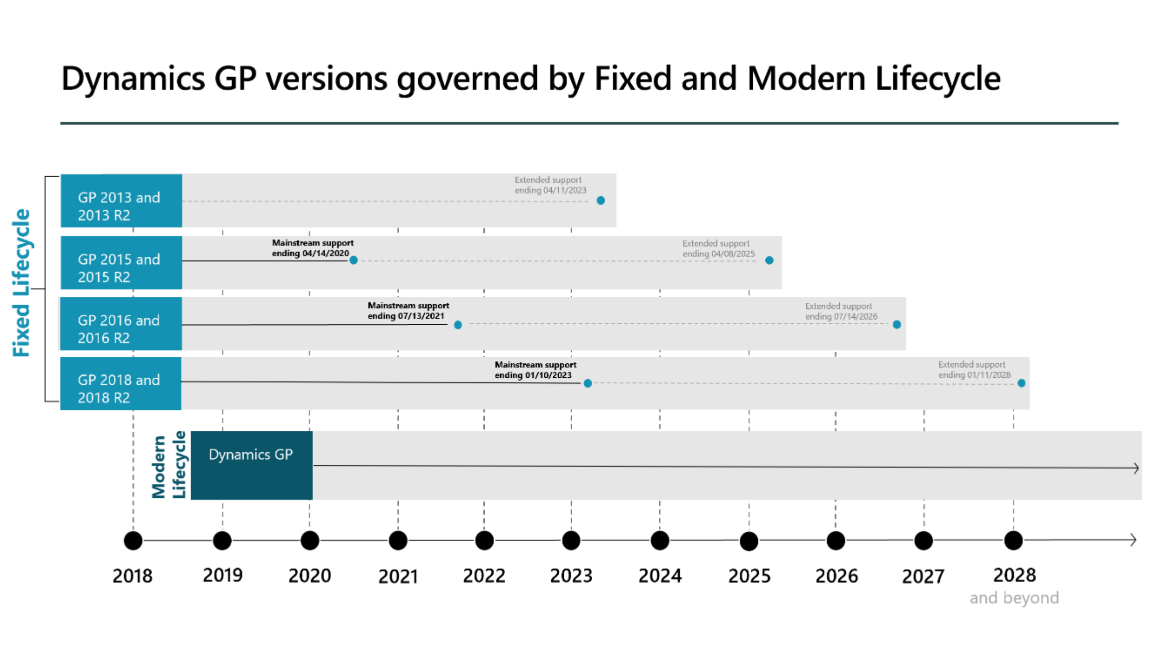
Figure 3- ESRI Support Table Summary

Multiple version table

Version	Release date	General Availability	Extended	Mature	Retired	Release notes	Addressed issues
10.8.2*	December 9, 2021	Dec 2021-Feb 2022	Mar 2022-Feb 2024	Mar 2024-Feb 2026	March 1, 2026	IMPORTANT NOTE: ArcGIS 10.8.2 is the current release of ArcMap and will continue to be supported until March 01, 2026. We do not have plans to release an ArcMap 10.9.x. This means the 10.8.x series will be the final release series of ArcMap and will be supported until March 01, 2026.	ArcGIS 10.8 Issues Addressed List

Lastly, in 2027, EPLC will be upgrading/replacing its accounting software as Microsoft announced end of life and phasing out sales of licenses for Microsoft Dynamics GP. Mainstream support for the version of Dynamics GP that EPLC owns has ended in January 2023, with extended support ending in January 2028. Due to financial data being critical to the organization, EPLC is taking steps to implement a new accounting software in 2027, ahead of the planned end-of-support in 2028. This will ensure critical information remains secure and de-risks the organization from any potential cybersecurity threat.

Figure 4- GP 2018 Fixed Lifecycle & Dynamics GP Modern Lifecycle



4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.8 A. General Information on the Project/Program

1. Overview

This program 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.

The program budget allows for the replacement of tools and equipment that have reached their end of typical useful life (e.g., 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 test year, 2025, 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.

2. Timing

i. Start Date: This is an annual investment initiative and will take place over the period of 2025 to 2029, with the start date being in January 2025.

ii. In-Service Date: 2025 to 2029

iii. Key factors that may affect timing: Key factors that influence the timing of these investments include:

- Supply chain issues;
- project prioritization, and
- overall budget constraints.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	50	31	58	46	46	64	100	100	72	74	76	79
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	50	31	58	46	46	64	100	100	72	74	76	79

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

EPLC periodically purchases or renews various tools that are used to carry out the operations and maintenance activities of the engineering, metering, and operations departments. Historical costs for the 2018-2023 period are reflected in Section A3. Historical costs have varied year over year in accordance with specific needs identified and have been impacted by other factors such as supply chain issues and budget reallocations to higher priority projects. The table below details a summary of work that was completed as part of this program over the historical period.

Year	Summary of Work Completed
2018	-Candura meter analyzer and associated components -Various traffic signs for MTO Book 7 requirements -Klein Impact Drills x5 -Chainsaws x3 -Portable Generator x2 -Pole tamper -Powerline Technician pole belt replacement -Pole positioning dolly for rear yards -Transformer deck dolly for rear yards -Additional Automated External Defibrillators x2 -Extendable switch sticks x3 -2 sets of pole tongs -Landscape equipment including hedge trimmer, and portable water tank with associated pump/hoses -Cement Saw
2019	-Achor Tool/Locking Dog assembly for backyard radial boom derrick -Material Handing Jib head x2 -Bluetooth probe for Metering -Portable generator -Spiking Tool -Wire rack -Replacement winch lines

	-PVC Heat blanket -Portable Water/Trash pump
2020	-Candura MIV System -Replacement of web hoists (4) -Powerline Technician pole climbing equipment -Replacement winch lines (2) -Ground Tents (2) -Extendable switch stick (2) -Chainsaws -Lawnmower -Battery Operated Klein Crimper/Cutter (3) -Spiking Tool -Klein Impact Drill 3)
2021	-Fall Arrest Harness (4) -Klein battery operated Crimper (2) -Klein battery operated cutter (3) -Rangefinder (3) -Wire height measurement device -Pruning saws with telescopic pole -Cable/Fault locator -Guy wire ratchet cutter (3) -Cansel Trimble GEO GPS -Conduit inspection camera for engineering
2022	-Elbow grounds -Class 4 Rubber gloves (4 sets) -Super Beast (3) -Hubbell Potential Indicator -Loadbuster Tool (4) -Kearney Crimping tool -Powerline Technician fall arrest equipment -Slugbuster tool -ARC Flash hood -Battery Operated Chainsaw (2) -Pole lifting tongs (2) -Potential Indicator -Burndy ratchet tool (2)
2023	-Powerline Technician Climbing Set (3)- -Smash anchor tool -Burndy Ratchet tool (5) -Milwaukee Platform Tools (including (8) impact drills, 4 drill/hammer drill combo kit, (2) 12-ton crimper, (2) 6-ton crimper/cutter combo kits)

Due to the nature of the projects within this program and the fact that purchases are completed on an as-needed basis depending on the type of work required, there are no good cost comparators available, and a comparison of historical projects and future projects is not indicative of any particular trend.

6. Investment Priority

Purchases for tools are completed on an as needed basis. Continual investment is required to ensure compliance and that EPLC staff are adequately equipped to maintain its distribution system safely and efficiently. Tools are required to perform routine maintenance on the distribution system.

Out of eleven (11) material projects/programs planned and prioritized an optimized through EPLC's process, this program was ranked 6th based on its Risk/Strategic Objective Score, as shown in Table 5.4-15 of EPLC's DSP.

7. Alternatives Analysis

EPLC management evaluates, on a case-by-case basis, three (3) primary alternative scenarios when it pertains to Tools: Do Not Replace, Like for Like Replacement, or Upgrade. EPLC management evaluates each of these scenarios for each Tools investment based on information from subject matter experts, third-party vendors, good utility practice, and regulation.

Generally, doing nothing is not a viable option. This would impede EPLC's ability to carry out the necessary operations and maintenance activities of the engineering and operations departments. Furthermore, it would put assets at risk of failure and expose customers to longer and more frequent outages in the event of preventable failures.

By carrying out the proposed pacing of investments, EPLC can invest in the tools necessary to carry out the operations and maintenance activities of the engineering and operations departments. These investments will also enable improved operational efficiency of field crews, lower operational costs, and reduce potential safety risks. Project specific alternatives including Like for Like Replacement or Upgrade are considered on a case-by-case basis depending on the identified need.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.9 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Having access to the proper tools and equipment in good working order allows field crews to perform their tasks in the most efficient manner.

Customer Value	By continuing to support daily operations and maintenance activities, these investments help to ensure performance measures targets are met including operational efficiency, reliability, and safety. The purchase of additional tools will also enable line crews to serve EPLC growing customer base.
Reliability	Continued investment in the proper tools ensures that the reliability of EPLC's system is maintained. Having access to the proper tools and equipment in good working order allows crews to perform their tasks in the most efficient manner, including operation and performing preventative maintenance to better assess the condition of its assets and eliminate or reduce the duration of the system interruption that would have been introduced had the asset failed. These investments also allow crews to respond to system interruptions faster and more efficiently, thus reducing the overall duration of system interruptions and improving reliability.
Safety	The purchase of proper tools help to reduce potential safety risks to EPLC staff. Tools are also necessary for EPLC to carry out maintenance activities, the results of which help inform which assets need investment, including in need of immediate investment due to safety concerns.

2. Investment Need

i. Main Driver: System Maintenance Support - The primary driver for this program is to improve its system maintenance support. The continued investment in various tools and equipment will ensure the continued safe, reliable, and efficient operation of the grid and enable field crews to carry-out maintenance activities in the most efficient manner.

ii. Secondary Drivers: There are no secondary drivers for this program.

iii. Information Used to Justify the Investment: EPLC used subject matter experts, third-party vendors, good utility practice, and regulation as metrics to justify the investment. Project specific alternatives are considered on a case-by-case basis. In addition, EPLC reviews best practices on current tools availability, trends and technology to ensure EPLC is inline with typical utility practice.

3. Investment Justification

i. Demonstrating Accepted Utility Practice*:* It is accepted industry practice that utilities invest in proper tools necessary to carry out operations and maintenance activities in a safe, efficient, and cost-effective manner. Continuous investment in proper tools and equipment is also required to avoid tool failure which would not allow crews to maintain the distribution system in a timely manner. Through investment in the proposed tools and equipment over the forecast period, EPLC will ensure that field crews have what they need to support daily operations and maintenance activities to better serve EPLC's growing customer base.

ii. Cost-Benefit Analysis: For any service/tools required without a contract, EPLC gathers three (3) quotes to ensure the best value is obtained in terms of cost and delivery time. Project-specific alternatives are also evaluated on a case-by-case basis depending on the identified need, and cost analysis is considered following EPLC's corporate purchasing policies.

iii. Historical Investments & Outcomes Observed: Historical costs are indicated in Section A3 of this document. Historical investments in proper tools and equipment have supported daily operations and have enabled EPLC field crews to carry-out maintenance activities in a safe, efficient, and cost-effective manner.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.10 A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

1. OVERVIEW

This program outlines EPLC transportation and fleet investments required over the forecast period. Vehicles and other mobile assets 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's current fleet vehicles are listed in Table 1.

Table 1: EPLC Fleet List (as of December 31, 2023)

Year	Vehicle Type	Vehicle Number	Ownership
2011	Freightliner – 46' Single Bucket Material Handler	107	EPL
2012	Freightliner – 42' Single Bucket	108	EPL
2014	Freightliner – 46' Single bucket Material Handler	111	EPL
2021	Freightliner – 42' Single Bucket	115	EPL
2022	Freightliner – 60' Single Bucket Material Handler	117	EPL
2020	Freightliner – 55' Double Bucket	114	EPL
2013	Freightliner RBD – 50 ‵	110	EPL
2015	Freightliner RBD – 50 ‵	113	EPL
2014	Dodge Ram CV	73	EPL
2016	Dodge Promaster	74	EPL
2016	Dodge Promaster	75	EPL
2016	Chevrolet Silverado 2500HD	76	EPL
2017	Chevrolet Silverado	77	EPL
2018	Chevrolet Silverado 2500 with Utility Body	78	EPL
2018	Chevrolet Silverado 2500 with Utility Body	79	EPL
2018	GMC Sierra 1500	80	EPL
2018	Ford F550 with Enclosed Utility Body	81	EPL
2019	Chevrolet Colorado	82	EPL
2019	Chevrolet Colorado	83	EPL
2019	Ford F350 Crew Cab with Utility Box and Lift Gate	84	EPL
2019	Ford F150 Crew Cab	85	EPL
2022	Ford F150 Hybrid Crew Cab	86	EPL
2022	Ford F150 Hybrid Crew Cab	87	EPL
2022	Chevrolet Colorado	88	EPL
2015	Ford F550 Super Duty Dump	112	EPL

2022	Ford F550 Super Duty Dump with attached snow plow and salter	116	EPL
2017	SDP EZ Hauler 55MP Backyard RBD and Tilt Trailer Combination Unit	741	EPL
1980	Utility Trailer	733	EPL
1992	Pole/Reel Trailer	731	EPL
2013	Landscape Trailer	734	EPL
1968	Timberland Reel Trailer	733	EPL
2019	Timberland Reel Trailer	743	EPL
1997	Extendable Pole Trailer	735	EPL
1997	Pole/Reel Trailer	736	EPL
2022	Extendable Pole Trailer	744	EPL
2019	Enclosed Utility Trailer	742	EPL
2014	Case Farmall 95C Tractor with Front Loader, rear box scraper and rear plow	740	EPL
2014	Toyota Forklift	N/A	EPL
2007	Vermeer Wood Chipper	361	EPL
2000	Viltech Trailer Mounted Building Generator	362	EPL

Fleet vehicles must be maintained at an optimum level to ensure public and employee safety, to comply with laws and regulations, to keep repair costs at a minimum, and to support functional needs and performance requirements associated with executing maintenance and capital investment plans.

To achieve the abovementioned goals, EPLC maintains a multi-year capital plan for its fleet and mobile assets. EPLC follows its Fleet Purchasing Policy, attached as Appendix H of the DSP, 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.

This is covered in more detail in the Fleet Purchasing Policy. In addition, EPLC utilizes the IRFS standard which indicates a typical useful life of 8 years for small fleet vehicles and 12 years for CVOR fleet vehicles. Table 2 outlines the proposed vehicle replacements during the 2025-2029 forecast period. Existing trucks are nearing end-of-life and require substantial maintenance, in alignment with EPLC’s Fleet Purchasing Policy.

Table 2: EPLC Fleet Replacement Plan (2025-2029)

Vehicle Replacement	Unit #	Replacement Year	Forecast Cost ($'000)
2017 Chevrolet Silverado	77	2025	70
2018 GMC Sierra 1500	80	2025	70
2013 Freightliner RBD 50"	10 (RBD)	2025	570
Replacement Pole Trailer	735	2025	75
On-Call Trucks (2018 Chevrolet Silverado 2500 with Utility Body)	78 &79	2026	275
2014 Freightliner 46" Single Bucket Truck	111	2026	540
2015 Freightliner RBD 50"	113	2027	620
Replace 2 Engineering Vehicles	82 & 83	2027	130
Replace Line Supervisor Vehicle	85	2027	70
2018 Ford F550 – UG Truck Enclosed Bed	81	2028	140
Ford F350 Crew Cab with Utility Box and Life Gate– Open Bed	84	2028	140
Single Axle RBD	N/A	2028	525
SDP Backyard RBD	741	2029	350
Stringing Trailers	N/A	2029	350
Landscape Trailer	734	2029	50

EPLC maintains a lean fleet inventory, and as such, does not have the option to rotate older vehicles into seasonal or a less critical type role, as well as does not have spare vehicles in case one of its fleet vehicles breaks down or is in need of servicing. Specialty equipment and extra equipment needed during critical times (i.e., extreme adverse weather events) are sourced via rental options on an as-needed basis to reduce costs of EPLC's overall fleet.

2. TIMING

iv. Start Date: This is an annual investment initiative and will take place over the time period of 2025 to 2029.

v. In-Service Date: 2025 to 2029

vii. Key factors that may affect timing: Key factors that affect timing include:

- Supply chain issues/constraints, and the adherence of fleet suppliers to the delivery schedule;
- project prioritization; and
- overall budget constraints.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	211	190	501	465	611	554	770	785	815	820	805	750
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	211	190	501	465	611	554	770	785	815	820	805	750

4. Economic Evaluation (Expansion Projects)

Economic evaluation is not applicable.

5. Comparative Historical Expenditure

Historical costs for the 2018-2023 period are reflected in Section A3 above. Historical costs have varied year over year in accordance with specific needs identified and fleet works undertaken. Some of the larger increases observed are explained below:

- Chassis costs for heavy trucks have increased due to increased raw material, labour, and freight costs. As well, many chassis' suppliers are on fleet allocations thereby creating a supply vs. 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. These 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.

6. Investment Priority

The planned investments in EPLC's fleet are based on the criteria established in EPLC's current Fleet Management Policy. The project ranked 3rd in its relative priority ranking, with a 3.476 strategic objective score, speaking to its relevancy and importance for maintaining and operating a safe and effective distribution system. EPLC's fleet replacement program looks at several factors including age of the vehicle, historical maintenance costs associated with said vehicle, and the business needs of the organization. Failure to replace vehicle(s) in coordination with EPLC's fleet replacement program and schedule further introduces a level of uncertainty into the level of performance the vehicles will have over time. Further, delaying the replacement of vehicles past their "useful life" opens EPLC up to the possibility of increased maintenance costs and downtime, thereby affecting overall throughput and project performance. Ensuring reliability of our fleet further creates a level of confidence within EPLC ensuring that we can continue to serve our customers effectively, efficiently, and as safely as possible while carrying out EPLC's capital and maintenance programs.

Continued investments in EPLC's fleet over the forecast period is needed to continue supporting business needs. Without proper fleet management, proactive and reactive work can fall behind thus increasing risks to safety and reliability and increasing costs. Delay of this project will result in increased OM&A costs and could moderately affect operational effectiveness. The following needs were identified and assessed when scoring the project:

Health and Safety- Having fleet vehicles in good condition is essential to the safety of EPLC's personnel and the public. Due to conditions beyond EPLC's control, vehicle and mobile assets are inevitably going to experience deterioration beyond repair. It is critical that EPLC replace these assets when they are no longer safe to continue operating.

Environmental Impact- EPLC continuously reviews the possibility of replacing its existing fleet (when nearing end-of-life) with electric vehicles. While this would have a positive impact on environmental controls, it is not currently feasible to convert to an electric fleet. EPLC will continue to monitor its existing fleet and perform proper analysis to determine the most optimal time to convert to emission friendly vehicles.

Service Quality (Reliability)- Mitigating fleet issues and vehicle failures will help EPLC continue to meet reliability standards and targets. Vehicles that are maintained and in good working condition will operate more smoothly, ensure higher levels of safety, and enable crew members to work efficiently and help maintain service quality.

Financial Impact- The financial impact of avoiding fleet replacement would result in increased maintenance costs and decreased resale value of vehicles. EPLC analyzes the financial impact of maintaining versus replacing its fleet to maximize cost efficiencies.

Out of eleven (11) material projects/programs planned and prioritized an optimized through EPLC's process, this program was ranked 3rd based on its Risk/Strategic Objective Score, as shown in Table 5.4-15 of EPLC's DSP.

7. Alternatives Analysis

The following alternatives were considered for the EPLC's Fleet replacement program:

i. **Do nothing**: This option is not viable as doing nothing will result in an increase in regular maintenance and repair costs and will not address the significant mileage accumulated on the vehicle identified. This option will also add risk to the operational efficiency of construction, restoration, and customer access to power and increases the risk of catastrophic failure which may threaten the safety of employees and the public. This alternative is not considered feasible since it will lead to an unexpected equipment failure, increased outage restoration times as well as increased maintenance costs and health and safety risk to line workers and the public.

ii. **Like for Like Replacement**: Under this option, EPLC replaces it vehicles as per its proposed plan. All vehicles are replaced with the same model. This is the most efficient and cost-effective option that EPLC can pursue.

iii. **Replace Vehicles with lower emissions vehicles**: Whilst EPLC does own a small number of lower emission vehicles, the cost to replace all vehicles with more costly lower emission vehicles is not prudent or practical. In addition, there is still uncertainty on how large electric trucks operate reliably. To protect its customers and staff from unintended consequences, EPLC continues to pursue a balance and prudent approach to purchasing lower emission vehicles. EPLC will continue monitor the progress of large electric trucks and will invest accordingly once reliability and costs have stabilized.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.11 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Consistent management of EPLC's fleet will ensure that life cycle costs and risks of catastrophic failure remain low. Planned replacement of the fleet ensures that the field team is using the most efficient and reliable equipment possible while on the job. Unreliable fleet can negatively impact utility performance, such as reliability and employee productivity, and as vehicles age, they incur higher operating expenses due to increasing levels of reactive repairs.
Customer Value	The replacement of end-of-life fleet vehicles will allow EPLC to maintain its ability to provide a timely, safe, and reliable service to customers. Having a safe and reliable fleet reduces operating and maintenance costs and mitigates the risk of work disruption and delays in customer service requests and/or outage response time to unplanned incidents, such as trouble calls and storm response, due to vehicle breakdown. The planned replacement of old and unreliable fleet also mitigates any catastrophic failure which may threaten the safety of employees and the public.
Reliability	The replacement of end-of-life fleet vehicles allows for the continued efficient day to day operations of the EPLC business. Having reliable vehicles is important to the delivery of reliable electricity to customers as outages are not unnecessarily prolonged due to vehicle breakdown when replacing the distribution equipment.

Safety	Planned replacement of fleet mitigates any catastrophic failure which may threaten the safety of employees and the public.

2. Investment Need

iv. **Main Driver:** Failure Risk - The main driver for this program is addressing the risk of failure of assets that are at end of typical useful life and operational effectiveness. All fleet vehicles are needed to support business needs, and over time, these units are subject to wear and tear that can impact vehicle safety, reliability, and operational efficiency. As vehicles age and mileage increases, they also incur higher operating expenses due to increasing levels of reactive repairs.

v. **Secondary Drivers:** System Maintenance and Capital Investment Support – Investments into fleet vehicles, including regular maintenance, replacements when vehicles reach end of typical useful life, and additions based on staff and customer growth is essential to ensure that EPLC continues to have access to safe and reliable vehicles that support system maintenance and capital investment activities.

vi. **Information Used to Justify the Investment:** The investment is justified based on EPLC's Fleet Management Policy, which considers the age and mileage for all gas/diesel powered vehicles (<4500kg and >4500kg). Details of this data are shown below:

Unit	Vehicle Type	Current Age (as of 2024)	Mileage (km)	Engine (hours)	Maintenance Costs ($)		
					2021	2022	2023
77	Chevrolet Silverado	7 years	125,799	4536	2,426	1,954	4,611
80	GMC Sierra 1500	7 years	103,567	3684	744	2,852	3,965
110	Freightliner RBD- 50"	11 years	111,477	7295	7,845	8,461	23,845
735	Extendable Pole Trailer	27 years	n/a	n/a	1,007	976	2,693

Over the 2021-2023 period, the overall maintenance costs of these assets have increased, as depicted in the chart above. In addition, the extendable pole trailer (unit 735) no longer meets the requirements and needs of EPLC due to limited carrying capacity and length of poles.

Vehicle investments and purchases are initiated using informal vendor quotes for purchase price and expected lead times. Due to COVID-19 and supply chain issues, lead times for vehicles and mobile assets have significantly increased. Additionally, due to supply chain constraints, there is a cap on orders for fleet programs. These lead times and procurement limits have been taken into consideration for EPLC's fleet purchase plan. To start the process of purchasing new vehicles and mobile assets, EPLC seeks multiple quotations through trusted third-party vendors. All quotations are reviewed prior to purchase to ensure the best value is obtained. To combat lead times and ensure EPLC's fleet remains safe and reliable, EPLC issues POs approximately 2 years in advance of the expected replacement year for vehicles such as bucket trucks, dump trucks, and RBD units. An example RFQ for one of EPLC's fleet vehicles is attached in Appendix I of this narrative.

EPLC utilizes the IRFS standard which indicates a typical useful life of 8 years for small fleet vehicles and 12 years for CVOR fleet vehicles. Following IRFS rules on depreciation and typical useful life allows EPLC to replace vehicles in a timely manner while still receiving a fair value for the vehicles upon disbursement. This avoids selling or disbursing the used vehicle when it has zero residual value and is proven to be most cost-effective for EPLC's fleet policy and procedures.

In addition, EPLC makes investments in its vehicles and equipment based on existing needs and analysis on improving both operational and cost efficiencies. As such, EPLC has sought to add a single axle RBD and stringing trailers to its fleet and equipment. By purchasing a single axle RBD, EPLC will no longer have to incur rental costs during the summer months. Work has increased in the summer over the last few years due to service needs, making renting uneconomical for EPLC. As such, adding a single axle RBD will be more cost-effective and operationally efficient for future work. Similarly, adding stringing trailers to EPLC's fleet equipment will create operational efficiencies for its crew by allowing for expanded capabilities and removing obstacles/barriers to existing work.

3. Investment Justification

- **i.** Demonstrating Accepted Utility Practice*:* In order to maintain the distribution system safely and reliably, it is imperative that EPLC's fleet vehicles remain in good, acceptable condition. Reliable fleet vehicles help EPLC achieve reliability targets by enabling crews to respond to outages in a timely and efficient manner. As an example, without proper working fleet vehicles, SAIDI metrics can increase through improper or unavailable vehicles during call responses. This would in turn, also affect metrics such as appointments met on-time. In addition, reliable fleets help EPLC efficiently construct new lines and deploy technologies that are more resilient against climate change.
- **ii.** Cost-Benefit Analysis: Ongoing fleet vehicle maintenance is needed to ensure that EPLC staff continue to have access to safe and reliable fleet vehicles needed to support business needs. When it comes to replacing an existing end of life fleet vehicle or purchasing a new fleet vehicle to accommodate staff and customer growth, alternatives are evaluated on a case-by-case basis, quotes are obtained from manufacturers, and cost analysis is considered following EPLC's corporate purchasing policies.
- iii. Historical Investments & Outcomes Observed: Historical costs are indicated in Section A3 of this document. Historical investments in fleet have ensured that EPLC continues to have access to safe and reliable vehicles that support system maintenance and capital investment activities. The proactive management of vehicles has also helped keep repair costs at a minimum.
- **iv.** Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.12 A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

1. OVERVIEW

New Service Upgrades for commercial and industrial ("C&I") customers are budgeted annually. The investment costs are associated with activities relating to plant relocation or plant upgrades to accommodate customer-related changes. Investments in road authority projects will permit EPLC to remove, relocate or reconstruct its distribution to support the C&I initiatives and the mandated requirements of EPLC's distributors licence. The extent of the project areas varies from year to year depending on the C&I customers overall plans and on the nature of EPLC's infrastructure in the area being addressed. EPLC consistently deals with a variety of yearly requests that are not known at the time of budgeting.

For the 2025 test year, EPLC is planning to complete, but not limited to the following projects:

Town of Amherstburg

- Commercial Development at the old Duffy's site (1 to 2 Commercial units)

Town of LaSalle

- Heritage Plaza Commercial Development (Approximately 20 commercial units). Some of the projected 20 will fall in 2024 with the remainder connecting in 2025.
- 6150 Malden Road - New three-storey hotel.
- LaSalle Landing Waterfront Development - 3 commercial services

Municipality of Leamington

- New Grocery Store at 126 Talbot St. South.
- Mixed Use Development at 320 Erie St. South, Windsor Family Credit Union (WFCU) and a new restaurant total of 2 Commercial units)
- 111 Sherk Street Mixed Use Building - 4 buildings totaling 12 Commercial units.

Town of Tecumseh

- PJ Cecile Pump Upgrade (Storm water management) at 14080 Riverside Drive East.

EPLC consistently deals with a variety of requests that are not known at the time of budgeting. Forecast costs are driven by historical trends and increased by inflation. Historically, spending in this category has been aligned to the forecast costs.

2. TIMING

i. Start Date: 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: The largest risk to completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity. EPLC has highly-trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings with customers take place frequently and at their request to best manage customer expectations.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	591	363	250	524	402	492	583	448	450	459	468	477
Contributions	307	208	111	440	191	159	365	255	260	265	270	275
Capital (Net)	284	155	139	84	211	333	218	193	190	194	298	202

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year. The future costs align with the expected load growth.

6. Investment Priority

New C&I Service Upgrades are made based on customer/developer request. This program is non-discretionary. The process is managed by EPLC staff through various systems to ensure proper visibility and timeliness. Projects within this program are executed with a high priority, as they are linked directly with the customers that EPLC serves, and connections must be made within timelines specified in the Distribution System Code.

7. Alternatives Analysis

No alternatives were considered, as these investments are a mandated service obligation.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.13 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from

	project to project and must be made in accordance with EPLC's Conditions of Service. Whenever possible, EPLC uses standardized designs. Final design and implementation decisions are made by EPLC's engineering department.
Customer Value	Customers benefit from a connection to the electricity grid. EPLC consistently meets with developers and customers to ensure that their needs are met in accordance with EPLC's Conditions of Service.
Reliability	Projects installed under this program are not intended for reliability improvements; however, all new construction is in accordance with EPLC current standards and specifications, which lend themselves to more reliable performance reducing the frequency of outages.
Safety	All new construction meets the latest distribution standards for safety.

2. Investment Need

New C&I Service Upgrades investments are made based on customer/developer request. These upgrades are a high priority for EPLC since they are linked directly with the customers that EPLC serves. Planning objectives such as reliability of the secondary bus and transformer loading are always considered; however, investments under this program are driven primarily by customer requests. Additionally, this project supports EPLC's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.

i. Main Driver*:* Mandated Service Obligations - These projects are mandatory. The scope and timelines are based on requirements put forth by customers and/or obligations set forth for connecting customers in the DSC.

ii. Secondary Drivers: Not Applicable.

iii. Information Used to Justify the Investment*:* New C&I Service Upgrades are driven by customer/developer request and are mandated by the OEB to be completed.

3. Investment Justification

i. **Demonstrating Accepted Utility Practice*:*** Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from project to project and must be made in accordance with EPLC's Conditions of Service. Whenever possible, EPLC uses standardized designs. Final design and implementation decisions are made by EPLC's engineering department.

ii. Cost-Benefit Analysis**:** This is not applicable.

iii. **Historical Investments & Outcomes Observed**: The historical costs are detailed in sections A3 of this document. Costs are generally driven by the specific requests of the customer/developer and can vary from project to project. EPLC employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer.

iv. **Substantially Exceeding Materiality Threshold:** This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.14 A. General Information on the Project/Program

1. Overview

Municipal Requests are costs associated with activities relating to plant relocation or plant upgrades to accommodate municipally requested changes. Examples of Municipal Requests include, but are not limited to, road widenings, right of way improvements, and utility relocation projects.

Investments in road authority projects will permit EPLC to remove, relocate or reconstruct its distribution to support the road authority initiatives and the mandated requirements of EPLC's distributors licence. The extent of the project areas varies from year to year depending on the municipality's / road authority's overall plans and on the nature of EPLC's infrastructure in the area being addressed. EPLC consistently deals with a variety of yearly requests that are not known at the time of budgeting.

For the 2025 test year, EPLC is planning to complete, but not limited to the following projects:

Town of LaSalle

- Howard/Bouffard Master Drainage Plan - Relocation of poles, guy wires, and hydro cable.
- Malden Rd. Improvements (Meagan to Normandy) - Relocation of poles, guy wires, and hydro cable.

Municipality of Leamington

- Leamington Streetscaping Project - Requires the relocation of poles, wires, and customer secondary services.

Town of Tecumseh

- Tecumseh Road East CIP Project (Relocate OH Southfield to Lesperance) - Multiyear road reconstruction project involving hydro plant relocation, service relocations, new power supplies to feed new traffic lights, etc.

Forecast costs are driven by a combination know project and historical trends and increased by inflation. Cost recovery for this program is typically based upon the cost apportionment set out in the Public Service Works Highway Act (PSWHA) which is identified as 100% material and 50% labour to be absorbed by the utility unless greater contributions are agreed on due to special requests by the Road Authority.

2. Timing

i. Start Date: 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: The largest risk to the completion of the program is the initiation of the work by the municipalities. The historical spending below shows that the actual spending can vary greatly between years depending on the amount of work requested by municipalities. To mitigate this risk, EPLC has highly-trained staff that work with project developers to manage timelines and to

best accommodate municipal requests. Meetings with municipalities take place frequently and at their request to best manage expectations.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	166	62	46	10	352	144	200	212	216	221	225	230
Contributions	130	7	21	3	23	91	17	20	20	20	21	21
Capital (Net)	36	55	25	7	329	53	183	192	196	201	204	209

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year.

6. Investment Priority

Since EPLC's assets occupy the public right of way, this work is mandatory; therefore, this program is non-discretionary. The municipal request process is managed by EPLC staff through various systems to ensure proper visibility and timeliness. The scope of work can vary wildly therefore timing and resourcing are closely managed and monitored by EPL staff.

7. Alternatives Analysis

No alternatives were considered, as this is a mandatory and non-discretionary program.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.15 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Project design and implementation options for this program are not known until the municipal request is received. In general, designs can vary for projects

	under this program and must be made in accordance with EPL's Conditions of Service. Whenever possible, EPL uses standardized designs. Final design and implementation decisions are made by EPL's engineering department. In addition, where possible EPLC also upgrades and replaces any assets that are in poor or very poor condition and at risk of failure at the same time as the municipal request.
Customer Value	Customers benefit from the work performed by the municipalities, which supports development and quality of life improvements in various communities. Some of these projects include community improvement projects; therefore, some areas can become more accessible, reliable, and aesthetically pleasing.
Reliability	While EPLC must comply with the request to move its assets for Road Authority projects, a detailed review is performed to improve reliability through updated standards, increase distribution automation and feeder redundancy.
Safety	All new construction meets the latest distribution standards for safety.

2. INVESTMENT NEED.

EPLC's planning objectives such as reliability and capacity are always considered; however, investments under this program are primarily driven by municipal infrastructure development requirements. Additionally, this project supports EPLC's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.

i. Main Driver*:* Mandated Service Obligations - These projects are mandatory. The scope and timelines are based on requirements put forth by customers and/or obligations set forth for connecting customers in the DSC.

ii. Secondary Drivers: Not applicable.

iii. Information Used to Justify the Investment*:* Municipal Requests are driven by municipal/shareholder request and are to be mandated by the OEB to be completed. EPLC has engaged with the local municipalities to understand any known plans they have that may require EPLC to relocate assets. This has been reflected in EPLC's forecast plans.

3. INVESTMENT JUSTIFICATION

i. *Demonstrating Accepted Utility Practice*: Project design and implementation options for this program are not known until the municipal request is received. In general, designs can vary for projects under this program and must be made in accordance with EPLC's Conditions of Service. Whenever possible, EPLC uses standardized designs. Final design and implementation decisions are made by EPLC's engineering department.

ii. *Cost-Benefit Analysis*: This is not applicable.

iii. *Historical Investments & Outcomes Observed*: The historical costs are detailed in sections A3 of this document. Costs are generally driven by the specific requests of the municipality or developer and can vary from project to project. EPLC employs good utility practice and engineering practices to ensure that costs are controlled and minimized.

iv. *Substantially Exceeding Materiality Threshold:* This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.16 A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

1. OVERVIEW

Residential Connections/Extension are costs associated with activities relating to services for individual customers of EPLC. Customer initiated requests for new/upgraded services are budgeted based on historical expenditure trends, growth predictions and consultations with municipalities and developers. The quantity of service projects varies annually and includes the design and installations of new/upgraded residential and commercial services. New connections and service upgrades are planned using standardized designs that meet the requirements of O.Reg. 22/04. EPLC consistently deals with a variety of customer requests that are not known at the time of budgeting. Forecast costs are driven by historical trends and increased by inflation. EPLC has forecasted an average of 385 individual secondary services annually for the 2025-2029 forecast period.

2. TIMING

i. Start Date: 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: The largest risk to completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity. EPLC has highly-trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings with customers take place frequently and at their request to best manage customer expectations.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	459	460	475	432	484	843	562	573	585	596	608	621
Contributions	178	181	182	178	218	298	227	231	236	241	246	251
Capital (Net)	281	279	293	254	266	545	335	342	349	355	362	370

4. ECONOMIC EVALUATION (EXPANSION PROJECTS)

Economic Evaluations are generally not applicable for new services where the bulk of the infrastructure is connection assets. However, at times where modifications to the distribution system are necessary they are completed in accordance with the Distribution System Code and are in either the Subdivisions or Other recoverable work programs.

5. COMPARATIVE HISTORICAL EXPENDITURE

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year. Historical costs show a steady increase, and EPLC expect to see this trend to remain for the forecasted period.

6. Investment Priority

New Residential Connections/Extension projects are made based on customer requests. This program is non-discretionary. The process is managed by EPLC staff through various systems to ensure proper visibility and timeliness. Projects within this program are executed with a high priority, as they are linked directly with the customers that EPLC serves, and connections must be made within timelines specified in the Distribution System Code.

7. Alternatives Analysis

No alternatives were considered, as these investments are a mandated service obligation.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.17 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from project to project and must be made in accordance with EPLC's Conditions of Service. Whenever possible, EPLC uses standardized designs. Final design and implementation decisions are made by EPLC's engineering department.
Customer Value	Customers benefit from a connection to the electricity grid. EPLC consistently meets with developers and customers to ensure that their needs are met in accordance with EPLC's Conditions of Service.
Reliability	Projects installed under this program are not intended for reliability improvements; however, all new construction is in accordance with EPLC's current standards and specifications, which lend themselves to more reliable performance reducing the frequency of outages.
Safety	All new construction is designed and built to meet the latest distribution standards for safety.

2. INVESTMENT NEED

New *Residential Connections/Extension projects* are made based on customer/developer request. These projects are a high priority for EPLC since they are linked directly with the customers that EPLC serves. Planning objectives such as reliability of the secondary bus and transformer loading are always considered; however, investments under this program are driven primarily by customer requests. Additionally, this project supports EPLC's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.

iv. Main Driver*:* Mandated Service Obligations - These projects are mandatory. The scope and timelines are based on requirements put forth by customers and/or obligations set forth for connecting customers in the DSC.

v. Secondary Drivers*:* Not Applicable.

vi. Information Used to Justify the Investment*:* New Residential Connections/Extension projects are driven by customer/developer request and are mandated by the OEB to be completed. EPLC has used historical trends to forecast the number of potential connections for 2025-2029.

3. INVESTMENT JUSTIFICATION

v. Demonstrating Accepted Utility Practice*:* Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from project to project and must be made in accordance with EPLC's Conditions of Service. Whenever possible, EPLC uses standardized designs. Final design and implementation decisions are made by EPLC's engineering department.

vii. Cost-Benefit Analysis**:** This is not applicable.

viii. Historical Investments & Outcomes Observed: The historical costs are detailed in sections A3 of this document. Costs are generally driven by the specific requests of the customer/developer and can vary from project to project. EPLC employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer.

ix. Substantially Exceeding Materiality Threshold: This is not applicable.

4. CONSERVATION AND DEMAND MANAGEMENT

This is not applicable.

5. INNOVATION

This is not applicable.

5.18 A. General Information on the Project/Program

1. Overview

Subdivision requests are costs associated with activities relating to plant relocation or plant upgrades to accommodate customer-related changes. EPLC consistently deals with a variety of requests that are not known at the time of budgeting. Forecast costs are driven by historical trends and increased by inflation.

These projects, which are nondiscretionary under the Distribution System Code (DSC) consist of numerous projects which are required for expansion and connection from EPLC's distribution system to new residential subdivisions / developments.

To accommodate these requests, a combination of new assets are required alongside some existing asset upgrades are required, including, but not limited to, pole replacements, overhead switch replacements/coordination, pad mounted switch replacements. All requests are reviewed against the DSC and current Conditions of Service to determine EPLC's contribution level.

Projects in this program are primarily driven by developer requests as is the investment prioritization under this program. Based on current subdivision plans and estimated timing from developers, EPLC expects to construct infrastructure that would add approximately 1,269 homes to its customer base in 2025 test year with a similar amount forecast for future years.

2. Timing

i. Start Date: January 2025
ii. In-Service Date: 2025 -2029
iii. Key factors that may affect timing: The largest risk to completion of this program as planned relates to the cost and timing of the investment. Projects within this program are initiated by customers and the actual spending can vary between years. This is an OEB-mandated activity. EPLC has highly-trained staff that work with project developers to the best of their ability to manage timelines and to best accommodate the customer. Meetings with customers take place frequently and at their request to best manage customer expectations.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	815	730	393	664	1,578	2,423	1,054	1,080	1,097	1,119	1,141	1,164
Contributions	434	392	168	529	945	1,687	492	502	512	523	533	544
Capital (Net)	381	338	225	135	633	736	562	578	585	596	608	620

4. Economic Evaluation (Expansion Projects)

Economic Evaluations are completed in accordance with the Distribution System Code and Subdivision Agreements for each new subdivision expansion project in the EPLC service territory to collect capital contributions, as well as to rebate customers over the connection horizon period. EPLC works with developers to complete these economic evaluations and collect and rebate as appropriate.

5. Comparative Historical Expenditure

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year. From 2021 onwards EPLC experienced a greater than 100% increase in residential buildings and subdivisions. This increase is largely due to new homes being built at a faster pace than before. In 2023 this increase leveled out and EPLC is estimating a more gradual increase over the forecast period.

For the forecast year costs, if designs have been completed, EPLC calculates its estimates from these. EPLC used the average cost of subdivisions/lot for the infrastructure, where detailed designs and estimates had not been completed. Then multiplied that by the number of lots expected in these developments in years where this information is known and used the historical average in years where unknown. For the forecast capital contributions, historical averages based on gross capital costs were used.

6. Investment Priority

New Subdivision connections are made based on customer/developer request. This program is non-discretionary. The process is managed by EPLC staff through various systems to ensure proper visibility and timeliness. Projects within this program are executed with a high priority, as they are linked directly with the customers that EPLC serves, and connections must be made within timelines specified in the Distribution System Code.

7. Alternatives Analysis

No alternatives were considered, as these investments are mandated service obligations.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.19 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary

	from project to project and must be made in accordance with EPLC's Conditions of Service. Whenever possible, EPLC uses standardized designs. Final design and implementation decisions are made by EPLC's engineering department.
Customer Value	Customers benefit from a connection to the electricity grid. EPLC consistently meets with developers and customers to ensure that their needs are met in accordance with EPLC's Conditions of Service.
Reliability	Projects installed under this program are not intended for reliability improvements; however, all new construction is in accordance with EPLC current standards and specifications, which lend themselves to more reliable performance reducing the frequency of outages.
Safety	All new construction is designed and built to meet the latest distribution standards for safety.

2. INVESTMENT NEED

New subdivision connections are made based on customer/developer request. These projects are a high priority for EPLC since they are linked directly with the customers that EPLC serves. Additionally, this project supports EPLC's Core Values of Customer & Community Value, Operational Excellence, and Financial & Environmental Sustainability.

i. Main Driver*:* Mandated Service Obligations - These projects are mandatory. The scope and timelines are based on requirements put forth by customers and/or obligations set forth for connecting customers in the DSC.

ii. Secondary Drivers: Not Applicable

iii. Information Used to Justify the Investment*:* New residential connections/expansions are driven by customer/developer request and are mandated by the OEB to be completed. EPLC has engaged developers to understand any specific projects they have for the forecast years, as well as used historical trends to forecast the number of potential connections for 2025-2029.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice*:* Project design and implementation options for this program are not known until the customer service request is received. In general, designs can vary from project to project and must be made in accordance with EPLC's Conditions of Service. Whenever possible, EPLC uses standardized designs. Final design and implementation decisions are made by EPLC's engineering department.

ii. Cost-Benefit Analysis: This is not applicable.

iii. Historical Investments & Outcomes Observed**:** The historical costs are detailed in sections A3 of this document. Costs are generally driven by the specific requests of the customer/developer and can vary from project to project. EPLC employs good utility practice and engineering practices to ensure that costs are controlled and minimized for the customer.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.20 A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

1. OVERVIEW

The purpose of this program is to replace overhead (OH) and underground (UG) assets which are at their End of Life (EOL). This program involves the proactive replacement of infrastructure including poles, UG cables, OH conductors, and transformers nearing or at the end of useful life. This is an annually recurring activity to replace aging assets, enhance safety, protect the environment, and improve system reliability. The types of projects that are included in this program include:

- Replacement of inaccessible rear lot infrastructure with standard front lot supply.
- Replacement of obsolete and end of life rear lot infrastructure with standardized assets.
- Specific, one-off projects to replacement of OH and UG infrastructure in a street or location that are at risk of failure and have reached end of life, and/or are obsolete assets.

EPLC has used a combination of the annual inspection data, pole testing, and customer servicing requirements to help identify and prioritize work in need of being addressed. EPLC has balanced the number of assets it will address with the customer-requested needs of servicing upgrades for the replacement requirements of pole line construction. Budgeting is reviewed annually based on the urgency of work required and potential safety hazards. EPLC intends to increase accessibility of all of its plant while limiting inconveniences to its customers.

Project & Description (Test Year 2025)
LAS Heritage Underground Rebuild (Primary Cable and Transformers)
LEA Shawnee Underground Rebuild (Primary Cable and Transformers)
TEC St. Thomas Overhead (OH) Rebuild (Rebuild OH line with new poles, cable, and transformers)
TEC Clarice OH Rebuild (Removing rear yard primary, replacing OH transformers (TX) with UG transformers, installing new secondary up new poles to service customers, project is to reduce faults.
LEA Bowman OH Upgrade (Like-for-like replacement poles, TX's, and UG cable. Upgrading OH secondary cables through backyards from open wire to OH triplex. Upgrade to improve reliability and safety
LEA Danforth OH Upgrade (Like-for-like pole replacement. Upgrade the open wire secondary to new OH triplex.
AMH Pickering OH/UG End of Life (EOL) Replacement (Replacing OH and UG transformers and poles)
LAS North Todd Lane OH Upgrade (Replace OH primary, poles and transformers. Install new OH secondary to replace open wire. From Elmdale to Sixth)
LAS Cousineau OH EOL Rebuild (Rebuilding OH pole line)

AMH Simcoe OH Rebuild (Rebuild OH pole line. Replace OH primary, secondary, poles and TXs)
TEC Riverside Drive OH Rebuild (Rebuild OH line, replace OH primary, secondary, poles and TXs)

Budgeting is reviewed annually based on the urgency of work required and potential safety hazards. EPLC intends to increase accessibility of all its plant while limiting inconveniences to its customers.

2. TIMING

i. Start Date: 2025

ii. In-Service Date: 2025 to 2029

iii. Key factors that may affect timing: Program timing and cost can be impacted since some of the work must be performed on customer premises. Customers are provided notice of the work well in advance to reduce the inconvenience and EPLC will ensure that the necessary signage and safety precautions are utilized. The work will be done by dedicated crews who are familiar with this type of work. EPLC considers the following as general risks to project schedule:

- customer delays or restricted access to work sites;
- availability of budgets;
- resources to accommodate higher priority / non-discretionary projects;
- inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- delays to material shipment from vendors; and
- general unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

EPLC has utilized coordination with third parties to mitigate some of the issues where possible, with municipalities/region/suppliers/customers.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	2,198	2,799	1,950	1,907	1,401	1,446	1,600	1,789	1,827	1,876	1,912	1,963
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	2,198	2,799	1,950	1,907	1,401	1,446	1,600	1,789	1,827	1,876	1,912	1,963

4. ECONOMIC EVALUATION (EXPANSION PROJECTS)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on the expected number of replacements planned/required.

6. Investment Priority

EPLC prioritizes conversions based on recent failures, age of plant, customer requests, and other planned work in the area of the conversion. All capital projects have been prioritized and optimized based on Financial, Service Quality, Community Image, Legal, Regulatory, Safety, and Environmental metrics. Public and employee safety is the highest priority objective for EPLC.

Out of eleven (11) material projects/programs planned and prioritized an optimized through EPLC's process, this program was ranked 4th based on its Risk/Strategic Objective Score, as shown in Table 5.4-15 of EPLC's DSP.

7. Alternatives Analysis

The following alternatives were considered for this project:

- **Option 1 – Do Nothing:** Accessing and servicing some of EPLC's infrastructure is challenging and often necessitates specialized equipment and contractors to complete the work. This makes accessing and servicing the infrastructure significantly more costly and time-consuming relative to servicing the equipment in more accessible locations. In addition, the age and condition of the existing equipment also poses a safety risk to workers and the public. Since this option does not address the safety, reliability and access issues that are inherent to the existing system, this is not a viable option.
- **Option 2 - Like-for-Like Replacement:** Like-for-like replacement is a common solution for a significant number of distribution system infrastructure replacements. This option is selected if infrastructure is easily accessible, the assets have reached end of life, and comply with the latest USF standards.
- **Option 3 – Enhanced Replacement:** This is similar to Option 2, however the infrastructure under this option has been identified as no longer meeting current USF standards. If this is the case, the asset is replaced with one that meets the latest standards. This is considered good utility practice. In addition, this option is selected when infrastructure is inaccessible or hard to access and prevents easy access for repair and maintenance. For example, this could be the moving and upgrade of hard to access rear-lot assets with front lots infrastructure.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.21 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current EPLC specifications and design standards and will improve reliability. Proactive replacement of an asset is more cost effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work and prolonged outage restoration time.
Customer Value	The proactive replacement strategy of the project as planned is less costly than reactive replacements. Proactive replacements help to minimize potential public safety risks and outage impacts to customers. Customers will receive value through faster response and restoration times. Customers will receive value through reduced unplanned outages, faster response times, less potential damage to customer property, and enhanced reliability.
Reliability	This program mitigates the risk of an unplanned asset failure and reduces outage restoration time. For OH conductors as an example, OH lines in the field are aged and deteriorating which can result in unplanned outages. This will particularly impact outages due to adverse weather and tree contacts on customer premises. Additionally, the proactive replacement of direct-buried cables reduces outage restoration time since duct-embedded cables can be repaired much quicker than direct-buried cables. Moreover, with ease of access to equipment, fast restoration can be achieved.
Safety	Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for EPLC staff and customers. Accessing plant in backyards can also prove to be difficult and unsafe. All new construction meets the latest distribution standards for safety.

2. Investment Need

i. Main Driver: Failure Risk - Assets that are at the end of their service life due to failure risk. Proactively identifying and replacing OH and UG assets minimizes the risk of a failure occurring, which reduces the risk of outages. This aligns with the customers' requirement of the utility maintaining a similar level of reliability and minimizing outages.

ii. Secondary Drivers: Safety and Reliability - in response to customer requests, this project will increase accessibility of all of its plant while limiting inconveniences to its customers.

iii. Information Used to Justify the Investment: EPLC has used a combination of the annual inspection data, ACA, and customer servicing requirements to help identify and prioritize work in need of being addressed.

3. Investment Justification

i. Demonstrating Accepted Utility Practice: EPLC plans and executes its OH and UG replacement program to accommodate customer requests and comply with regulations. All new assets installed comply with the latest standards and regulations.

ii. Cost-Benefit Analysis: In the case of the "do nothing" option, customer requests to increase accessibility will not be met and accessing plant in backyards can also prove to be difficult, unsafe, and cost-ineffective since specialized equipment is oftentimes required in order to minimize customer inconvenience. Replacing with direct-buried cables would require the right of way to be dug up again in case of a future cable failure, which is sub-optimal. Converting specific sections of the underground feeders would not be feasible and would reduce the satisfaction of the affected customers.

Rebuilding in backyard does not solve the clearance issue which is one of the motives of these projects. In most cases, a spot pole replacement is equivalent to a like-for-like replacement and does not solve the accessibility issue for assets on customer premises. Undergrounding an existing OH circuit is much more expensive and, therefore, not recommended.

For UG cable projects, replacing the direct-buried cable with duct-embedded cable runs is the optimal trade-off between benefits and costs, providing the most benefits to EPLC's customers. Additionally, for OH conductor projects, rebuilding OH lines in the right of way at the front of a property eases access for EPLC staff resulting in safer work and creates less inconvenience for the customer in circumstances where EPLC needs to access its equipment and results in faster restoration times.

iii. Historical Investments & Outcomes Observed: Historical costs are presented in Section A3 of this document. The proactive replacement strategy of the project as planned is less costly than reactive replacements. EPLC's strategy has been to sustain the system and continue to maintain reliability and continue to minimize outages, and this is what has been seen during the 2018-2023 period.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.22 A. General Information on the Project/Program

1. Overview

The purpose of this program is to replace underground (UG) and overhead (OH) that arise within the year that have not been planned for due asset failure, customer complaints or compliance issues. This project also deals with storm damage and repairs that are capital in nature including pole, transformer, conductor, switch, and switchgear replacements.

EPLC is obligated to maintain safe and reliable power to its customers. While EPLC conducts regular inspection and maintenance of the distribution system and prioritizes planned replacements, there are times when a failure in the distribution system occurs and emergency replacement to restore power to customers is of paramount significance. Additionally, any assets identified that require immediate replacement due to safety concerns or imminent failures, accidents, theft, or vandalism are part of reactive capital. Investments in reactive capital projects will continue to support supply to customers and the requirements of EPLC's distributors license. While EPLC performs annual inspection and maintenance activities to aide in the proactive replacement of assets, a number of unexpected failures still take place requiring immediate actions.

EPLC has experienced on average 14 unexpected failure a year since 2018 across its main asset classes:

Asset Class	2018	2019	2020	2021	2022	2023
Poles	0	1	1	0	0	1
Overhead Lines	0	0	1	1	0	0
Underground Lines	0	1	0	3	0	1
Polemount Transformers	9	9	4	6	6	6
Padmount Transformers	3	6	5	9	6	4
Total	12	17	11	19	12	12

As the nature of work in this project is largely unplanned, unpredictable, and can vary significantly from year to year, EPLC has based its 2025-2029 forecast costs and projected reactive work volumes for this project on historical trends. Budgeting is reviewed annually and is based on historical spending trends adjusted for expected inflation.

2. Timing

i. Start Date: This is an annual investment initiative to replace failed assets and will take place over the time period of 2025 to 2029.
ii. In-Service Date: 2025 to 2029

iii. Key factors that may affect timing: EPLC considers the following as general risks to project schedule:

- customer delays or restricted access to work sites;
- availability of budgets;
- resources to accommodate higher priority / non-discretionary projects;
- inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- delays to material shipment from vendors; and
- general unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

EPLC has utilized coordination with third parties to mitigate some of the issues where possible, with municipalities/region/suppliers/customers.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	166	228	182	498	318	318	230	257	262	269	275	282
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	166	228	182	498	318	318	230	257	262	269	275	282

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on the actual number of events incurred. It should also be noted, that like other utilities, EPLC has seen a significant increase in costs, due to supply chain and material cost issues. In 2023 and onwards, EPLC has experienced 70% rise in costs due increases of material and transportation costs.

Asset Class	2018	2019	2020	2021	2022	2023
Poles	0	1	1	0	0	1
Overhead Lines	0	0	1	1	0	0
Underground Lines	0	1	0	3	0	1
PoleMount Transformers	9	9	4	6	6	6
PadMount Transformers	3	6	5	9	6	4

6. Investment Priority

This is a non-discretionary program and of highest priority. Customer restoration is an OEB-mandated activity and, therefore, this activity is required to ensure the efficient safe restoration of a reliable supply. Due to the nature of this project, and the fact that EPLC is obligated to repair and replace assets that have failed unexpectantly to restore customers as quick as possible, this program has been excluded from EPLC's optimization and prioritization process.

7. Alternatives Analysis

The alternative to this program is a "do nothing" approach; however, doing nothing is not an option with failed assets as they need to be repaired/replaced for customer restoration. Design alternatives, where applicable, are evaluated for each case to ensure that restoration is completed quickly and cost effectively.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.23 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current EPLC specifications and design standards and will improve reliability. EPLC uses standardized designs that have been engineered and approved in order to build efficiencies into the process.
Customer Value	Customers will receive value through faster response and enhanced reliability as a result of the replacements.
Reliability	Failed OH and UG equipment, if not responded to by EPLC crews, pose significant safety and reliability concerns for EPLC staff and customers alike.
Safety	Proper asset management of old and deteriorating equipment in the field mitigates safety concerns for EPLC staff and customers. Accessing plant in backyards can also prove to be difficult and unsafe. All new construction meets the latest distribution standards for safety. Furthermore, the risk of a dig-in in the customer's backyard is mitigated.

2. Investment Need

i. Main Driver: Failure Risk - Assets are at the end of their service life due to failure.

ii. Secondary Drivers: The secondary drivers are safety and reliability. Storm conditions can present safety-related risks to both EPLC staff and customers. Failed assets need immediate repair or replacement for quick restoration. Other major cost drivers include third-party tree trimming, on-call premiums, etc.

iii. Information Used to Justify the Investment: This program is required to replace failed assets and for fast restoration. Customer restoration is an OEB-mandated activity. Public/employee safety is one of the top objectives of EPLC's asset management. Failed assets, if not replaced/repaired immediately, pose safety hazards; therefore, this is investment is highly required. Due to the nature of the work being unpredictable and emergent and therefore reactive, EPLC has used historical asset failure information to help forecast the potential number of asset failure it may experience each year.

3. Investment Justification

i. Demonstrating Accepted Utility Practice*:* EPLC executes its OH and UG replacement program to accommodate customer requests and comply with regulations. All new assets installed comply with the latest standards and regulations.

ii. Cost-Benefit Analysis: This is not applicable.

iii. Historical Investments & Outcomes Observed: Historical costs are presented in Section A3 of this document. Reactive spending over the historical period was less than the long-term average attributed to an increase in the per unit cost to replace OH and UG assets. In 2023 and onwards, there was a 70% rise in costs due increases of material and transportation costs.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.24 A. General Information on the Project/Program

1. Overview

EPLC relies on poles to support distribution system attachments and maintain safety for the public, as poles provide physical separation between ground level and energized conductors. EPLC must maintain these assets in a safe and serviceable condition in order to maintain a safe and reliable supply to its customers.

EPLC owns 6,736 poles, of which 6,037 are made of wood, 158 are made of concrete, and 541 are riser poles. The Pole Replacement Program focuses on wood poles. The Typical Useful Life (TUL) is 45 years for wood poles. While age is a factor, EPLC utilizes the results of the ACA to ensure a detailed condition-based review is completed prior to selecting candidates for replacement. Whilst the majority of EPLC's wood pole population is in very good and good condition (83%), there is still apportion of poles that are at risk of failing in the next five years that will require replacement. EPLC's 2023 ACA identified 204 (3%) wood poles in very poor condition, with a further 90 (1%) in poor condition that will be required to be addressed during the forecast period. Figure 1 illustrates the HI results for EPLC's wood poles.

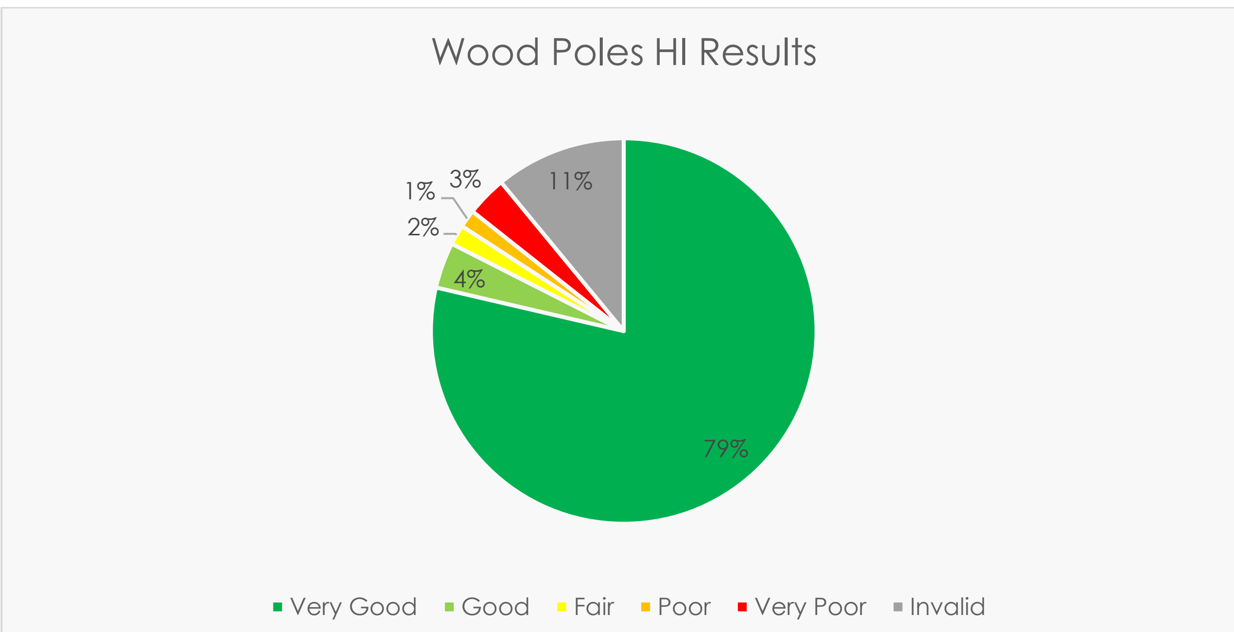


Figure-1: Summary of Wood Poles Health Index

The purpose of this program is to replace poles that have either failed or are at the end of their service life due to failure risk. Through its thorough preventative maintenance program, EPLC reviews the condition of its poles continuously to limit failure and maximize safety via non-destructive testing methods such as drilling. Budgeting is reviewed annually based on preventative maintenance program findings and availability of resources.

Investments in pole replacements will mitigate safety and reliability risks associated with the failure of these assets and maintain regulatory compliance with respect to minimum strength values.

EPLC must assess and monitor the condition of its pole population to ensure that its poles remain in a safe and serviceable condition while meeting prescribed codes for safety and reliability. EPLC does this through pole inspection and testing programs every three (3) years. The poles to replace were flagged through EPLC's preventative maintenance program and asset condition assessment.

EPLC complies with industry standards from Canadian Standards Association (CSA) in its overhead construction, namely CSA Standard C22.3 No. 1-10 [cite in DSP]. Clause 8.3.1.3 of the Standard states: "When the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced". EPLC is governed by the Electrical Safety Authority (ESA) standards, guidance, and reporting requirements as part of its compliance. Without the planned pole sustainment investments, EPLC would not be able to adhere to the adopted CSA standards and risk compliance with ESA and other regulatory entities.

EPLC plans to replace approximately an average of 60 poles a year across the 2025-2029 period as part of its Pole Replacement Program. Overall EPLC is proposing to replace a similar number of poles to its historical period. The cost are increasing due to mainly increases in material costs, which the whole industry is experiencing, with costs having increased by almost 60% in recent years.

2. TIMING

i. Start Date: 2025
ii. In-Service Date: 2025 to 2029
iii. Key factors that may affect timing: EPLC considers several factors that could impact the project schedule, including:

- customer delays or restricted access to work sites;
- availability of budgets;
- resources to accommodate higher priority / non-discretionary projects;
- inclement weather, either in the form of extreme temperatures or due to restoration activities following major storms;
- incremental risk in dealing with auguring holes during the winter months where sub-zero temperatures can persist;
- delays to material shipment from vendors; and,
- general unforeseen delays such as striking rock when digging, tree conservation, municipal/regional consent forms.

EPLC has utilized coordination with third parties (municipalities/suppliers/customers) to mitigate some of the issues where possible. Additionally, EPLC aims to mitigate weather related issues by scheduling around predictable adverse weather conditions.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

	Historical Costs ($ '000)	Bridge Year	Test Year	Future Costs ($ '000)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	181	706	531	402	602	734	195	1,097	811	250	1,173	884
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	181	706	531	402	602	734	195	1,097	811	250	1,173	884

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs are provided above that show comparative expenditure information. Note that actual costs can vary dramatically from year to year based on the expected number of replacements planned/required. In 2023 and onwards, the cost of pole replacements increased by 60% due to material cost increases and use of vacuum excavation. This has been experienced across the industry.

Asset Class	2018	2019	2020	2021	2022	2023
Poles	21	102	54	34	70	97

6. Investment Priority

Within the System Renewal investment category, this project is assigned the highest priority. Proactively identifying and replacing poles minimizes the risk of a failure occurring, which reduces the risk of prolonged, uncontrolled power outages and safety risks.

The planned pole investments are needed to address the volume of deteriorated poles on EPLC's distribution system and comply with external codes/standards. Proactively identifying and replacing poles that are decrepit (poor and very poor condition) and close to failure minimizes the risk of a failure occurring, which reduces the risk of prolonged, uncontrolled power outages. This aligns with the customer’s need for the utility to maintain a similar level of reliability and minimize outages.

Out of eleven (11) material projects/programs planned and prioritized an optimized through EPLC’s process, this program was ranked 1st based on its Risk/Strategic Objective Score, as shown in Table 5.4-15 of EPLC’s DSP.

7. Alternatives Analysis

Every three years EPLC conducts field inspections of poles and uses the inspection results to update the ACA and to prioritize and select suitable candidates for replacement. Some of the options that are considered when evaluating a pole replacement:

i. Do nothing and run to fail: EPLC does consider reactive replacement for some pole replacements. While this can be employed for unplanned and unexpected failure of poles, it is not sustainable to carry out for all pole replacements. Customers would experience longer and increased unexpected outages. In addition, replacing poles reactively generally incurs a premium as they are unplanned and inevitably are replaced outside normal hours and therefore resource costs increase. This ultimately would increase reactive renewal costs. In the case of a failed pole, doing nothing is not an option as a pole is required to support the overhead conductors and provide proper clearances. In the case of a pole at risk of failure, doing nothing would not achieve the project benefits of eliminating risks to public and employee safety, maintaining system reliability, and avoiding future O&M (trouble call) costs.

ii. Like for like replacement (proactive): This is the standard approach when inspection and ACA data indicates that a pole needs replacing. All poles are replaced with the latest standard design. The proposed proactive replacement of unsafe poles will ensure that the number of unplanned outages remains minimal by avoiding asset failures, so that the customers have access to reliable electricity for their needs. Costs will also be reduced when compared with completing all poles under a reactive program.

iii. Upgrades: If a pole has been identified as needing upgrading this is typically done with coordination with third parties, customers, road authority, and expansion developments. If these are driven by a third-party then these are carried out under System Access projects.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.25 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	The infrastructure will be upgraded to current EPLC specifications and CSA and USF design standards and will improve reliability. The proactive replacement of an asset is more cost-effective than an unplanned, reactive replacement, which may require overtime crew-hours for emergency work. EPLC utilizes a one-visit approach when considering pole replacement projects to minimize the return visits to upgrade or replace pole attachments at a later date. (i.e., whilst replacing a pole, EPLC will see if assets attached to it or in the vicinity also require replacement).
Customer Value	The investment will eliminate the concerns of low line clearances and imminent pole failures that could pose a safety and reliability risk. The

	proactive replacement strategy of the project is less costly than reactive replacements.
Reliability	This project is part of the long-term pole remediation program and will enable EPLC to maintain reliability.
Safety	Pole failures pose safety risk to staff and the public. The pole may fail when staff are working on the pole or when the public is in the proximity of the unit. When the pole falls, there may be other equipment (e.g., overhead transformer or overhead switch) that could also fall. This project will directly address and help eliminate these safety issues by replacing poor and very poor condition poles.

2. INVESTMENT NEED

The planned pole investments are needed to address the volume of deteriorated poles on EPLC's distribution system and comply with external codes/standards.

i. Main Driver: Failure Risk – the main driver is to minimize the failure risk associated with very poor or poor conditioned poles as identified in the ACA.

ii. Secondary Drivers: System operational objectives including safety and reliability. Through the proactive replacement of poor and very poor conditioned poles, EPLC can minimize safety issues, as well as maintain reliability levels.

iii. Information Used to Justify the Investment: Pole failures pose a safety risk to staff and the public. In the case that there are transformers on the pole, a pole falling down may also cause the transformers to fall down and fail. Hence, EPLC utilises its GIS system to overlay the poles identified, through its 2023 ACA, as decrepit (poor and very poor) with its system map to identify the locations and how many customers could be impacted (as well as critical infrastructure connected e.g., a hospital) by an unexpected failure, resulting in a transformer tank rupturing, and oil being spilled onto the ground. EPLC identified approximately 4% of its wood pole population of being in poor and very poor condition and in need of replacement in the next five year period.

3. INVESTMENT JUSTIFICATION

i. Demonstrating Accepted Utility Practice*:*

EPLC complies with industry standards from Canadian Standards Association (CSA) in its overhead construction, namely CSA Standard C22.3 No. 1-10 [3]. Clause 8.3.1.3 of the Standard states: "When the strength of a wood pole structure has deteriorated to 60% of the required design capacity, the structure shall be reinforced or replaced". When replacing the decrepit poles, EPLC will consider certain components of the pole framing for reuse after a thorough inspection. Given that the pole and all equipment on it are generally the same age, refurbishment is not likely an option. However, certain items such as down guys and stand-off brackets may be considered for reuse or a second lifecycle to minimize costs where possible.

In addition, it is prudent and a good utility practice to assess any assets that are associated with the pole to determine if they require replacement at the same time or if they can be transferred to the new pole. EPLC utilizes a one visit approach when considering pole replacement projects to minimize the return visits to upgrade or replace pole attachments at a later date.

ii. Cost-Benefit Analysis:

Running the poles to failure is an option that is considered, and some poles are addressed reactively by EPLC. However, this is not a feasible option to consider for all poles, as this would result in a backlog of poles that require replacement or treatment above EPLC's execution capabilities. In addition, this would significantly reduce the reliability of the system and cause more outages to customers. Although continuing to run poles to failure may reduce the level of targeted capital investment in replacement, the risks associated with this alternative are not worth the cost savings due to increased safety, reliability, and system performance risks.

EPLC is proposing to proactively replace the identified poor and very poor condition poles on a like for like basis and upgrade them to the latest standards where they don't currently meet it. As distribution poles are considered an integral and critical component of the distribution system there is no alternative to like for like replacement beyond the height or wood makeup of the replaced pole. The benefits of like for like replacement is the ability accurately forecast pole health and degradation and apply consistent inspection techniques to health assessments, providing efficiency and cost savings in O&M going forward.

iii. Historical Investments & Outcomes Observed:

Historical costs are presented in Section A3 of this document. The proactive replacement strategy of the project as planned is less costly than reactive replacements. EPLC's strategy has been to sustain the system and continue to maintain reliability and continue to minimize outages, and this is what has been seen during the 2018-2023 period. Reliability levels have typically been maintained and safety from falling poles has continued to be addressed.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.26 A. General Information on the Project/Program

1. Overview

This program outlines the investments EPLC are proposing to purchase asset from HONI to manage its capacity needs. The program is an initiative to transfer assets between EPLC and HONI so that each distributor controls assets within a geographical distribution service territory boundary and can manage their own capacity needs efficiently and effectively. During the forecast period, 2025-2027, EPLC plans to purchase assets in two of its service areas. This is required to facilitate long-term load transfer removal as well to accommodate significant growth within EPLC service areas. EPLC has been actively engaged with HONI in the recent years to identify the areas where EPLC needs to purchase assets from HONI to facilitate EPLC capacity needs and determine HONI's willingness to sell them.

This purchase will also facilitate the capability of shifting loads within the EPLC's service territory. The shifting of loads is to alleviate potential zones of constraint and ensure a flexible network that can easily be modified according to customer demand and changing situations within the Distribution network. A key element of these purchases is to enable EPLC to have a more integrated and controllable smart grid, with ownership of assets that are in EPLC control and have an impact to servicing its customers.

EPLC will purchase assets in three feeder sections in Amherstburg and two feeder sections in Leamington. All feeder sections are 100% within EPLC's service area and terminate within it.

The Amherstburg sections are continuous defined by street boundaries as follows:

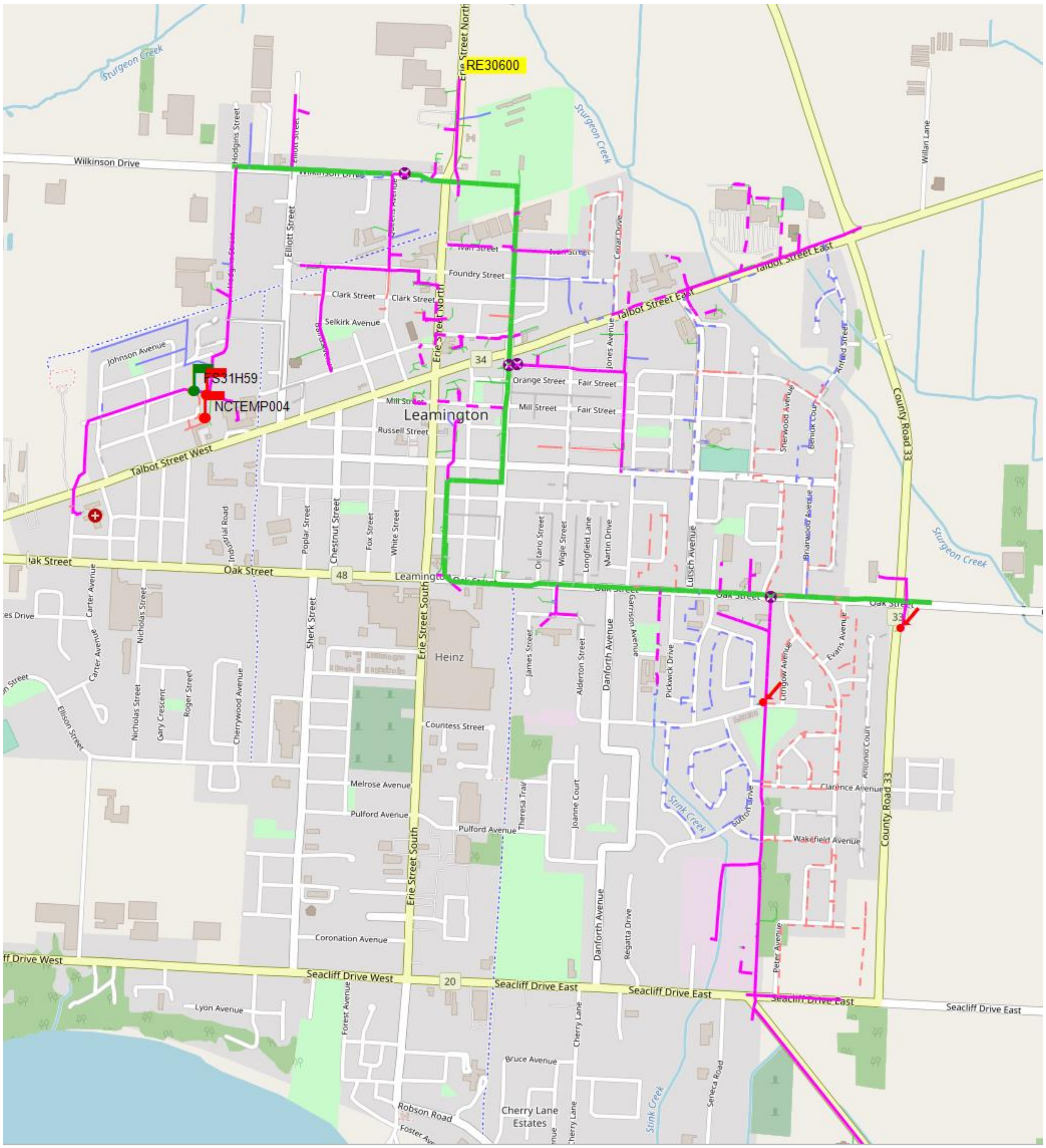
1) A 1.3 km section along Simcoe Street from Meloche Road to Fryer Street.
2) A 1.3 km section along Fryer Street from Simcoe to Lowes Side Road.
3) A 1.3 km section along Meloche Road from Alma Street to Simcoe Street; This section of feeder contains an embedded distribution of 6 HONI customers where settlement occurs each year.

In total, the three sections in Amherstburg comprise 88 wooden poles of various condition, age, height, and class, 3.9 km of 3/0 ASCR in a 3-phase configuration (3 lines – total of 11.7 km). This would also include any associated hardware, brackets, crossarms, insulators and switches.

The proposed purchase of the Leamington sections are described below. EPLC is currently rolling out it's planned smart grid investments. Control of key switches within its service area will be critical and will simplify the planning of any automation rollout. The current assets HONI own on these feeders are nearing end of life and are of older standard construction and are considered a potential weak point in EPLC's smart grid plan. Any major load is often connected to these two feeders. Connecting to HONI owned lines requires coordination with local HONI crews - as well as any future maintenance. The nature of the routing of both feeders increases the likelihood of involving work crews from both companies. This can be complex at times. The rules over who can install and touch what specific devices can seem meticulous and unnecessary especially how, as in this case, the HONI owned plant is more ubiquitously placed than is normally encountered. EPLC wishes to promote a simpler and straight forward interconnection between HONI and EPL systems. This has the added benefit of simplifying control, and ongoing maintenance and expansion work.

EPLC is proposed to purchase the feeders 393M24 and 393M27 from HONI to help mitigate the issues outlined above. The following shows the locations of the feeders and portions owned by HONI currently.

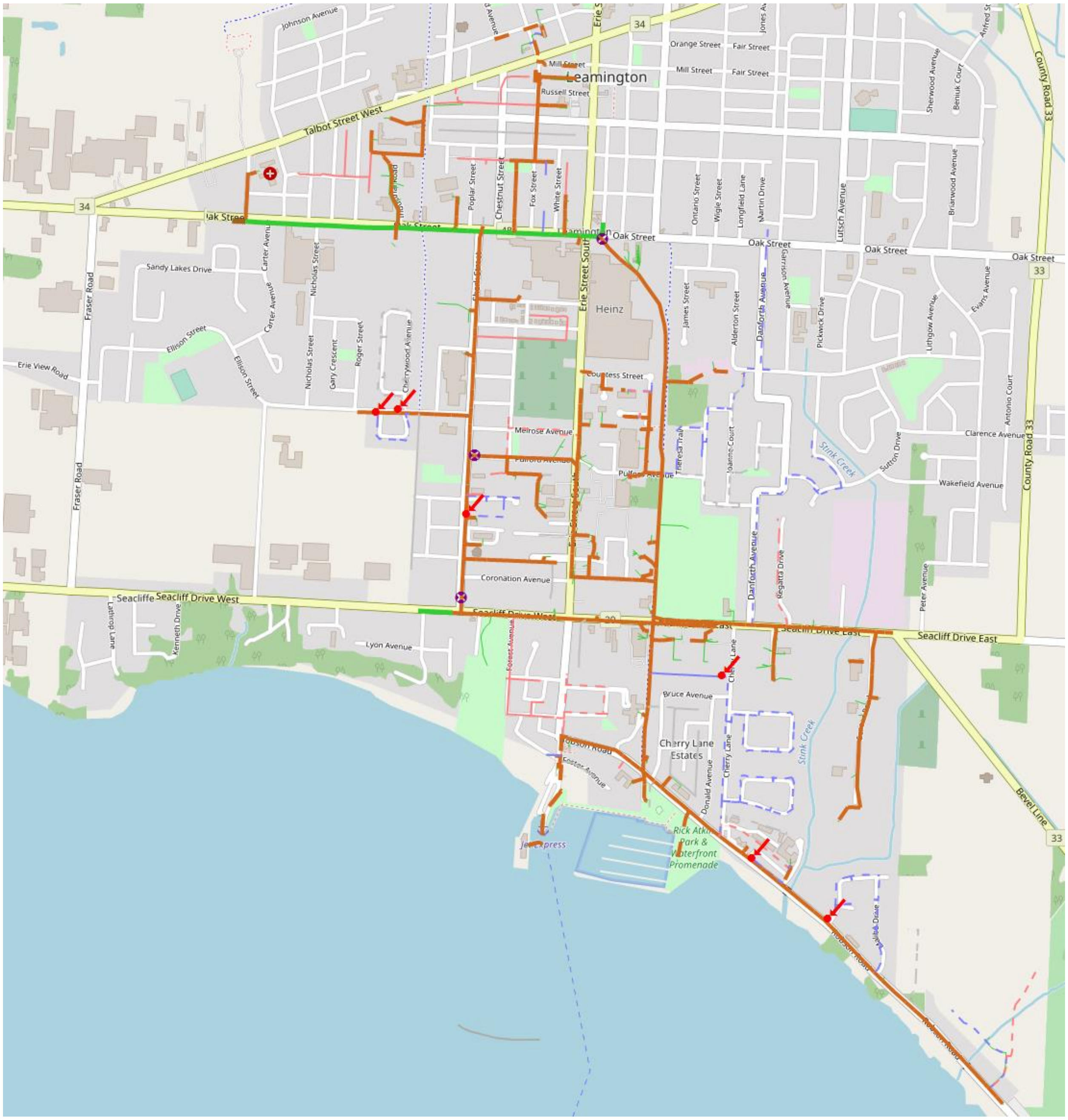
393M24



The thicker green line denotes HONI ownership. All other colours indicate EPLC owned line.

1. The feeder itself is **not** currently dedicated to EPLC. There is some HONI customer load before the wholesale meter. All load after the wholesale meter ● is EPLC customer load.
2. EPLC has numerous lateral ties from the main line. These numerous tie points increase the complexity of the interface between HONI and EPLC. EPLC has dozens of single and 3 phase laterals that branch off this main feeder trunk to supply EPLC customers.
3. The feeder lies totally within EPL territory, downstream of the wholesale meter.
4. Any load growth, after the wholesale meter would be within EPLC's territory.
5. Many of the switches along the HONI owned line are critical to EPLC to establish work protection or to restore power. Currently, the control of these switches is with HONI. This unnecessarily complicates control and coordination to establish isolation or restore power. Through the transfer of the feeder to EPLC, it will provide EPLC with more control of these feeders and be able to address outages easier.
6. There is a key feeder tie OAKM27-M24 identified by ●. As a feeder tie, it is desirable to convert this switch over to an automated style switch that will be a key component of our planned smart grid system. This switch is currently owned and controlled by HONI. Again, this ownership and control unnecessarily complicates operation of the system and planning for future system automation.
7. There are 3 feeder ties, identified by ● that would allow 393M24 to connect to 393M23 and 3M6. However, to do so would require the installation of some form of temporary metering for settlement purposes. None of these tie points could be closed under normal operating conditions.

393M27



The thicker green line denotes HONI ownership. All other colours indicate EPL owned line.

1. The feeder itself is currently dedicated to EPLC with no HONI load on it. All load after the wholesale meter ● is EPLC customer load. There is a retail meter at the end of the feeder denoted by ● that supplies some HONI customer load as the feeder exits EPL territory.
2. EPLC has numerous lateral ties from the main line. These numerous tie points increase the complexity of the interface between HONI and EPLC. EPLC has numerous single and 3 phase laterals that branch off this main feeder trunk to supply EPL customers.

3. The feeder lies totally within EPLC territory and only ties to the 393M24 feeder.
4. Any load growth, after the wholesale meter would be within EPLC territory.
5. Many of the switches along the HONI owned line are critical to EPLC to establish work protection or to restore power. Control of these switches is with HONI. This unnecessarily complicates control and coordination to establish isolation or restore power.
6. There is a key feeder tie OAKM27-M24 identified by . As a feeder tie, it is desirable to convert this switch over to an automated style switch that will be a key component of our planned smart grid system. This switch is currently owned and controlled by HONI. Again, this ownership and control unnecessarily complicates operation of the system and planning for future system automation.
7. The nature of the feeder layout and its interconnectivity with EPLC complicates system control, troubleshooting and response times. EPLC prefers clear lines of demarcation in order to reduce operating complexity, bureaucracy and potential confusion in the field over ownership and control of specific assets.

2. Timing

i. Start Date: 2025
ii. In-Service Date: 2025 to 2027
iii. Key factors that may affect timing: The program could be impacted by

- Either a change in direction from EPLC or HONI to allow the selling and purchasing of the relevant assets
- Market conditions

3. Historical and Future Capital Expenditures

	Historical Costs ($ ‘000)						Bridge Year	Test Year	Future Costs ($ ‘000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	318	0	0	0	0	0	700	384	768	884	0	0
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	318	0	0	0	0	0	700	384	768	884	0	0

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

There are no comparable historical costs as HONI has not sold any assets to EPLC in the historical period.

6. Investment Priority

EPLC identifies areas that are at risk of capacity issues within its service areas and has prioritized, in discussion with HONI, which assets it could purchase from HONI to mitigate these issues and effectively manage long-term load transfers.

Out of eighteen (18) material projects/programs planned in the 2025 Test Year, this program was ranked 8th based on its Risk/Strategic Objective Score, as shown in Table 5.4-15 of EPLC's DSP.

7. Alternatives Analysis

The following alternatives were considered for this project:

- **Option 1 – Do Nothing:** This is not an ideal solution. In this case EPLC would continue working closely with HONI to coordinate operation of the system for both preventative and reactive situations. However, loss of supply events has continued to become the largest portion of EPLC's total customer outages, and EPLC is looking at ways to manage this directly themselves.
- **Option 2 – Proposed Purchases:** The proposed purchase will help EPLC manage capacity transfers and improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.27 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	EPLC customers will experience a reduced length of time for connection requests as EPLC no longer has to coordinate with HONI for make ready work. EPLC will also see a reduction in joint use charges for the purchase year and all years following the purchase.
Customer Value	EPLC customers will see an improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project. Ongoing implementation of this project will also see minor reduced OM&A costs over time as overtime and overall crew hours are reduced.
Reliability	This project will lead to improved reliability as EPL strives to limit its exposure to Loss of Supply events. By gaining

	control of the assets serving its customers, EPLC will have the ability to move loads between the feeders to quickly restore power to the customers.
Safety	EPLC employees will see safety-related improvements as EPL staff will control the assets that serve its customers.

2. Investment Need

i. Main Driver: System Operational Objectives – Through the purchase of these assets EPLC will be able to reduce outages over loss of supply with the increased ability to carry out load-switching more effectively.

ii. Secondary Drivers: Efficiency – As EPLC will have control of these feeders, any connections related to these feeders would become more efficient, as EPLC would not need to coordinate with HONI. It would also be expected that the overall cost of the connection could be reduced in most cases.

iii. Information Used to Justify the Investment: EPLC has assessed which areas of its network are most vulnerable to loss of supply (LoS) events and minimal ability for EPLC to carry out its own load switching. All areas of EPLC's service territory are vulnerable to loss of supply as EPLC is embedded within HONI territory and EPLC does not own any Transmission Stations or Breaker positions that EPLC is connected to. The LaSalle and Amherstburg areas are more susceptible to LoS due to the non-contiguous nature of these two service territories and the shared feeders that transition from LaSalle to HONI to Amherstburg. Having the capability to isolate an external fault at its service boundary and shift the isolated, non-faulted section to another feeder can effectively eliminate LoS and provide a more flexible resilient Distribution network.

3. Investment Justification

i. Demonstrating Accepted Utility Practice*:* EPLC wants more control in its ability to address loss of supply events. It wants to be able to have the ability for long-term load transfers when events happen and is looking to improve its reliability through minimization of outage durations.

ii. Cost-Benefit Analysis: EPLC customers will see an improvement to outage length and severity as Loss of Supply events are reduced through the implementation of this project. Ongoing implementation of this project will also see minor reduced OM&A costs over time as overtime and overall crew hours are reduced.

iii. Historical Investments & Outcomes Observed**:** Historical costs are presented in Section A3 of this document. The proposed investment will eliminate any remained long term load transfers.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. INNOVATION

This is not applicable.

5.28 A. General Information on the Project/Program

1. Overview

EPLC is planning an initiative to upgrade its residential infrastructure to support customers upgrades from 100A to 200A, in line with the Ontario Energy Board (OEB) Bulletin issued on August 24, 2023, on Residential Customer Connections, Service Upgrades, and newly constructed homes. This Bulletin provides OEB staff guidance to electricity distributors regarding the basic connection for residential customers. It also describes the obligations under the Distribution System Code (DSC) when determining the cost responsibility for residential customer service upgrades. Customers power needs have continued to grow, demanding greater capacity to accommodate new technologies and devices, such as electric vehicle (EV) charging stations or hot tubs. These upgrades will meet current demands and future-proof homes, ensuring they can seamlessly integrate new technologies as customer needs evolve. EPLC has created a new investment program that will address this growing need.

Over the planning horizon, the costs of the initiative are expected to total $1.5M. EPLC is expecting to upgrade approximately 8 combined overhead and underground infrastructure per year from 100A to 200A.

2. Timing

i. Start Date: 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: The below listed factors can impact the timing of the proposed investments:
- Resource constraints;
- Supply chain issues;
- Project prioritization; and
- Overall budget constraints.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	0	0	0	0	0	0	0	274	288	319	351	371
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	0	0	274	288	319	351	371

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

As this is a new standalone program, EPLC does not have any historical expenditures.

6. Investment Priority

This investment is considered to be of low priority. While deferring investment does not pose a direct safety or operational risk, in the long run it will impact EPLC's customers and operations, which may require more costly remedial efforts.

Out of eleven (11) material projects/programs planned and prioritized an optimized through EPLC's process, this program was ranked 9th based on its Risk/Strategic Objective Score, as shown in Table 5.4-15 of EPLC's DSP.

7. Alternatives Analysis

i. Do nothing: Inaction is not a viable option. The proposed investments will improve residential electrical infrastructure and consequently improve safety, reliability, and efficiency. While deferring investment may not have immediate consequences, in the long run it will impact EPLC's customers and operations, which may require more costly remedial efforts.

ii. Carry out the proposed pacing of investments: This is the preferred option as it satisfies customer needs and secures EPLC's future operations. EPLC evaluates the identified needs to determine which are most critical to undertake and which can be monitored and pushed out to later years. Project-specific alternatives are considered on a case-by-case basis depending on the identified need.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.29 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	This upgrade facilitates the seamless incorporation of modern appliances and technologies, optimizing energy use and preventing potential bottlenecks. The increased electrical capacity ensures that households can operate efficiently without the risk of overloading. Proactively making these upgrades over the planning horizon is more efficient than staggered, as-needed upgrades for homes in the future.
Customer Value	Customer value is maximized through the upgrade, as it future-proofs homes and adds tangible market value. The increased amperage capacity accommodates emerging technologies that residents can more readily engage with.

Reliability	The completion of the upgrades will make EPLC's systems less vulnerable to disruptions. The expanded electrical capacity caters to the growing power demands of modern living, ensuring a robust and reliable electrical system.
Safety	The move from 100A to 200A significantly reduces the chances of circuit overloads, mitigating the risk of electrical fires and hazards.

2. Investment Need

i. Main Driver: Capacity Upgrade - The proposed upgrades from 100A to 200A will accommodate the increased power demands of EPLC's customers. reliability and safety by reducing the likelihood and impact of outages, improving response time in the event an outage occurs, and consequently exposing personnel to fewer risks when addressing events.

ii. Secondary Drivers: System Operational Objectives – The timing of the investment is intended to accommodate the growing needs of EPLC's customers. As adoption rates of new technologies (such as EVs) continues to grow, it is important to implement these upgrades before they become a critical burden on EPLC's systems.

iii. Information Used to Justify the Investment: EPLC continuously monitors the condition and effectiveness of its systems and assets. In addition, EPLC has reviewed its customer base and historical requests for upgrades to 200A. This data has informed the decision-making process for undertaking this project. Furthermore, EPLC has used the Ontario Energy Board (OEB) Bulletin issued on August 24, 2023, on Residential Customer Connections, Service Upgrades, and newly constructed homes to further identify the need for these investments.

3. Investment Justification

i. Accepted Utility Practice: In line with growing power needs, modern homes are now designed with 200A of capacity. These upgrades serve to bring older homes in line with new builds and align with the approach the rest of the industry is taking.

ii. Cost-Benefit Analysis: EPLC rigorously assesses the costs and benefits of undertaking new projects. This includes analyzing the costs and benefits of implementation, the consequences of deferral, and evaluating multiple quotes when working with other partners, emphasizing both cost-effectiveness and timely delivery. The proposed upgrades will mitigate the likelihood and impact of outages and disruptions, consequently reducing the costs associated with these events in the long-term.

iii. Historical Investments & Outcomes Observed: This project is a unique initiative in that does not have a historical equivalent that it can be compared to.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.30 A. General Information on the Project/Program

1. Overview

The purpose of this program is to replace EPLC's metering assets due to communication failure, technology limitations requiring upgrades due to regulation changes, or seal expiry. The program also includes gatekeeper and modem replacements to enhance connection and reliability of data. Budgeting is reviewed annually based on communication and data needs of new technologies as well as historical spending trends adjusted for inflation.

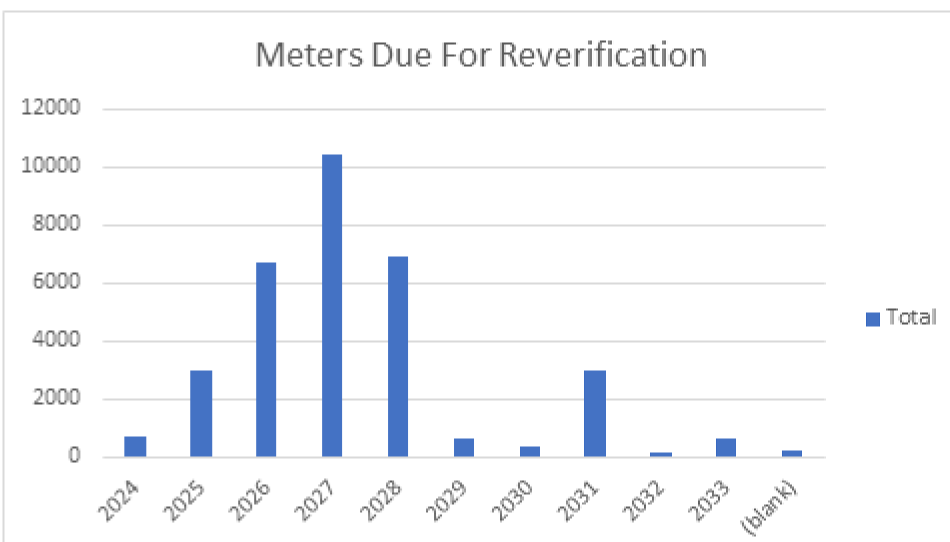
In addition, EPLC AMI1.0 is reaching its end of useful life and becoming technologically obsolete. This program outlines EPLC plans to assess the optimal option of upgrading the AMI1.0 to AMI2.0, as well as investigating the potential impact of continuing to use the existing AMI 1.0 technology.

Metering

EPLC owns and operates 31,453 revenue meters, installed on its customers' premises for the purpose of measuring electric consumption and demand of connected load for the purpose of billing. Since these investments are required by the DSC and Measurement Canada standards, they are considered non-discretionary.

Customer connection requests are fulfilled consistent with EPLC's Conditions of Service. The projects are designed to meet customer requirements and maintain system reliability and efficiency. EPLC uses standardized designs that have been engineered and approved to build efficiencies into the process. Through the implementation of this program, EPLC can continue to accurately and correctly measure and bill customers for the electricity that they use and satisfy the OEB "Billing Accuracy" requirement to have 98% billing accuracy.

Measurement Canada requires LDC's to reverify meters individually or in sample groups to ensure valid accuracy standards are maintained. From 2025 – 2029, Essex Powerlines has a significant number of meters due for reverification.



Over 84% of EPLC's meters are due for reverification between 2025-2029. Over 72% of EPLC's meter due for reverification will have already surpassed their Useful Life and it will be their 2nd reverification which will grant a maximum seal extension of 6-years.

The 2025 Test Year expenditure forecast includes the purchase of 984 meters and 8 gatekeepers. All new meters include network connections to Advanced Metering Infrastructure ("AMI").

AMI2.0

The following section outlines EPLC overview of its forecast AMI2.0 upgrade starting in 2027.

EPLC initiated the deployment of its initial Advanced Metering Infrastructure (AMI 1.0) system back in 2007 following the directives of the Province of Ontario. The AMI 1.0 system comprises approximately 31,453 smart meters interconnected through a mesh network with 45 gatekeepers. These meters transmit data to their respective Head End System (HES) via meters, repeaters, and collectors, with data subsequently relayed back to EPLC over cellular or ethernet networks.

As the AMI system ages, the frequency of meter failures, particularly communication loss, has surpassed standard operating levels, with meters exhibiting signs of deterioration. Currently, EPLC experiences around 500-600 meter failures a year, with EPLC seeing an increasing trend in the last few years. Left unchecked, these high failure rates pose significant risks to EPLC's operations, including non-compliance with regulatory standards under the federal Electricity Gas and Inspection and Weights and Measures Acts, and the OEB's DSC and billing provisions of the Standard Supply Service Code (SSSC), customer dissatisfaction due to billing inaccuracies, uneconomical reactive meter replacements, and operational disruptions stemming from technological obsolescence. Furthermore, over 63% meters are at or will reach their useful life by 2025 and over 71% by 2029. Therefore this is an optimal and prudent time to upgrade to AMI 2.0 during this period. It is further noted that the AMI1.0 technology is becoming obsolete and will not meet the needs of EPLC customers in the future to facilitate new technologies. EPLC's PowerShare innovation project is aimed at enabling the utility DSO model. AMI2.0 is one of the key grid modernization initiatives that is critical in supporting the DSO model.

The need to replace AMI 1.0 infrastructure also creates benefits and opportunities as there have been significant advancements in the technology since the AMI 1.0 system was commissioned close to 15 years ago. AMI 2.0 is a foundational investment in a modern AMI platform to address foreseeable needs over its service life.

The AMI 2.0 project consists of replacing both the software and hardware components of EPLC's existing AMI system. This investment is expected to maintain billing accuracy, optimize network communications, reduce manual meter reads (only meters in an electrical room that blocks the signal from getting out would need manual reads), provide faster response times to disconnection/reconnection requests, provide more accurate outage information, and provide customers with a modern AMI platform to meet foreseeable customer needs over the lifetime of the assets. The program will employ the newest generation of equipment to meet current needs and provide a platform to address foreseeable future needs over the investment's service life.

Updating this metering infrastructure will empower ELPC's operations in several ways:

- Ensure billing accuracy.
- Optimize network communications.
- Facilitate disconnection/reconnection requests.
- Capture more detailed outage information.
- Enable more robust data analysis.
- Facilitate engagement with customers through a mobile app.
- Provide real-time meter data to enhance live distribution model, real-time control, DER management, and future distribution system operation (DSO) models.
- Improved customer experience.
- Potential to support managed EV charging, vehicle to grid.
- Enable consumers to transition to prosumers.
- Reduce supply chain constrains – first generation vendors may be prioritizing AMI 2.0 meters over AMI 1.0.
- Support integration of DERs and home analytics for managing DERs, as well as other grid modernization activities.

These elements will work in concert to improve operational efficiency, improve interactions with customers, and reduce O&M costs. The program will employ the newest generation of equipment to meet the current needs and provide a platform to address foreseeable future needs over the investment's service life.

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

- Less manual meter data estimation and rebilling each month.
- Significantly less reactive meter replacements each month. Currently EPLC performs around 500 reactive meter exchanges annually, with the expectation that once AMI 2.0 is fully deployed that this would decrease by 20-50%. AMI 1.0 failure rates have begun to increment.
- The AMI 2.0 solution also includes a 100% coverage model to be able to read all meters with the proposed installation.
- Less truck rolls for certain disconnects/reconnects as it can be remotely done.
- No meter reverifications needed for 10 years after meters are installed.
- Reduced supply chain constraints due to vendors prioritizing manufacturing of AMI 2.0 meters over AMI 1.0.
- No more RMA's and associated costs to replace single meters which are non-communicating.

EPLC is currently in its exploratory stages of reviewing the most prudent investment option that will deliver for all its customers. During the forecast period, EPLC will carry out the following:

1. 2025 - Carry out RFP process for identification of vendor and product selection.
2. 2026 – Produce Detailed Project and Roll-out plan.
3. 2027 onwards – Deployment of AMI2.0.

EPLC plans to file an ICM application, during the forecast period, with the OEB once it has completed the RFP and options analysis process.

2. TIMING

i. Start Date: 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: There is a schedule risk for the installation of meters at new service locations due to customer delays or restricted access to work sites. EPLC is in regular communication with vendors to ensure customer value and is upgrading meters, where required, to avoid data related problems in the future.

Additionally, inclement weather and delays to material shipment from vendors can potentially impact timing. The final project cost also depends on the amount of labour required for each meter installation and the cost of materials.

If any meter installation is delayed due to inclement weather, EPLC will reschedule the job within a short time period to complete the work, typically within 1-2 days.

In 2020, the lead times for new meter orders increased substantially and to date the lead times remain significantly greater than they were prior to the global COVID pandemic. Prior to the pandemic, EPLC's expected lead times were approximately 6 weeks and since the global pandemic our current lead time is approximately 56 weeks. In response to the increased meter lead times, EPLC began forecasting metering inventory further in advance to maintain sufficient inventory levels to support customer growth and maintain existing metering assets. EPLC will continue to employ this strategy on an ongoing basis.

3. HISTORICAL AND FUTURE CAPITAL EXPENDITURES

Table 3: Historical and Forecast Expenditures ($'000)[6]

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	208	269	332	223	190	253	787	395	403	411	419	428
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	208	269	332	223	190	253	787	395	403	411	419	428

4. ECONOMIC EVALUATION (EXPANSION PROJECTS)

This is not applicable.

[6] The forecast costs do not include the projected AMI2.0 costs.

5. Comparative Historical Expenditure

Metering services are ongoing annual expenditures. Historical costs are reflected in Section A3 above. In the previous six historical years, EPLC has purchased 6,395 meters that have been used for replacement of failed meters, connection of new service, and maintaining sufficient meter stock. The following table shows the number of meters purchased each year from 2018-2023. Meters are purchased into inventory and exact installation timing depends upon the needs of customers.

Table 4: Number of Meters Purchased Per Year

Year	# of meters purchased
2018	742
2019	1701
2020	104
2021	1810
2022	768
2023	1270

6. Investment Priority

This investment program is classed as a high priority / non-discretionary due to the obligation to connect new customers, replace failed meters, provide safe and reliable power to customers, maintain billing accuracy and the need to comply with mandated service obligations as defined by the DSC and Measurement Canada.

7. Alternatives Analysis

This is a mandatory project and a regulatory requirement. Metering asset management is governed by Measurement Canada regulations and customer requirements for new and upgraded services.

No alternatives were considered since failure to perform the work to install, repair, replace and/or reseal meters would be in violation of the DSC and Measurement Canada Guidelines, and has the potential to negatively impact the reliable source of billing settlement data.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.31 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Customer connection projects are driven by customer requests and the customer's specific technical requirements. EPLC uses standardized designs that have been engineered and approved in order to build efficiencies into the process. Customer connection requests are fulfilled consistent with EPLC Conditions of Service. Additionally, through proactively addressing meters that are expiring, EPLC will have reduced the number of meters that would be susceptible to unexpected failure and therefore reduce the cost for having to reactively repair these meters.
Customer Value	Benefits to the customer include timely service and supply of electricity coupled with all tariffs (e.g., Time of Use) pricing and data visibility, translating to higher customer confidence. Additionally, by proactively renewing existing meters that are expiring, will ensure that customer meters continue functioning, capturing accurate electricity usage, and therefore enable EPLC to produce an accurate bill.
Reliability	These investments can improve the reliability of data provided to the provincial Meter Data Management Repository and billing system. New meters communicate a "last gasp" to EPLC's self-healing grid in case of a loss of power. This information facilitates accurate assessment of the grid condition to restore the maximum number of customers as soon as possible.
Safety	New meters conform to the latest safety standards.

2. Investment Need

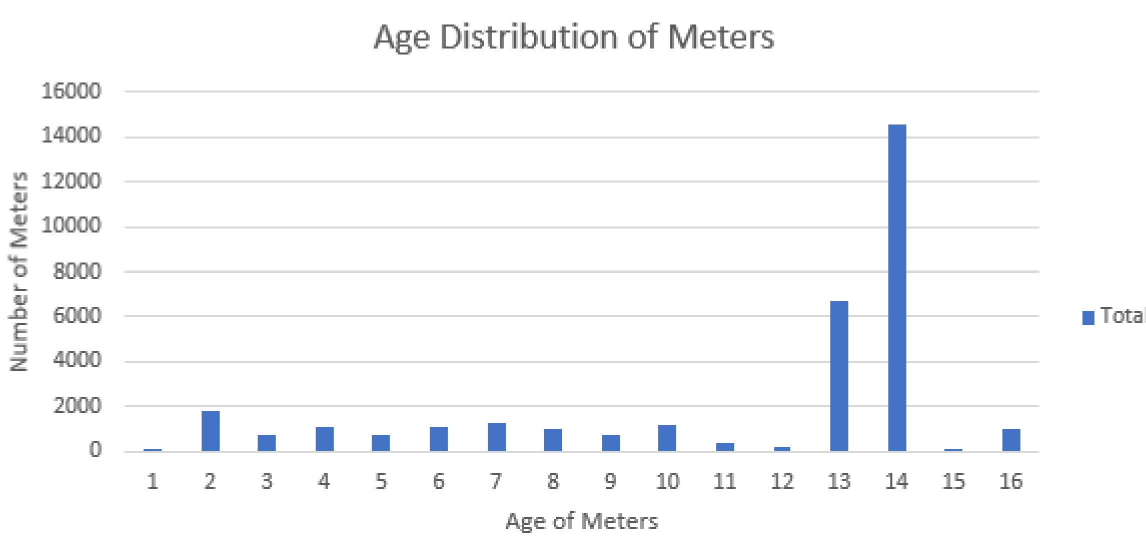
This project directly complies with EPLC's asset management objectives of meeting regulatory requirements and accommodating load growth.

iv. Main Driver*:* Mandated Service Obligations – The main driver for this program is EPLC's obligation related to metering services as defined by the DSC and Measurement Canada. EPLC is obligated to install and maintain meters at all customer connection points for both residential and commercial customers. By accommodating new connection requests and by replacing meters that have expired with new meters, EPLC ensures that it complies with its obligations to provide, install, and maintain a meter installation for retail settlement and billing purposes for each customer connected to the distribution system.

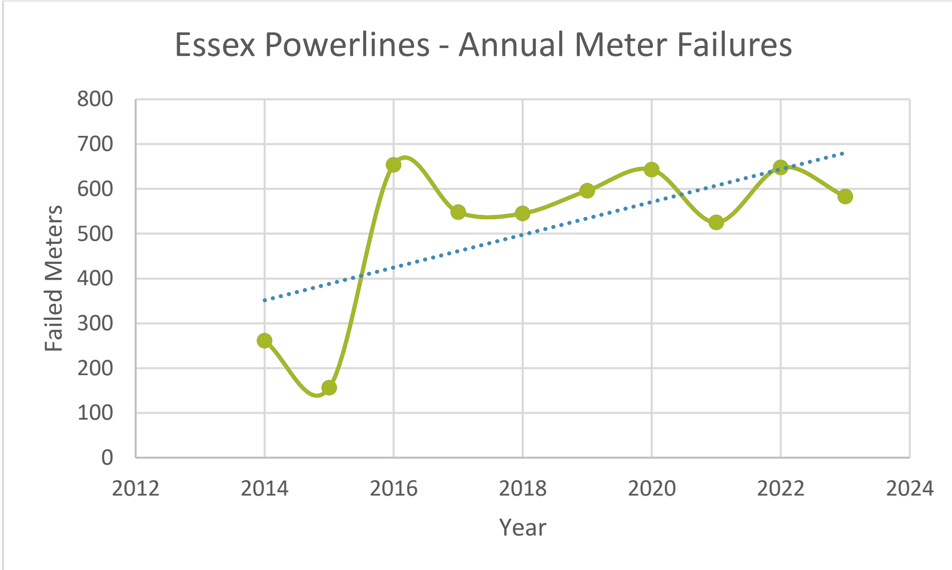
v. Secondary Drivers: Failure Risk – By addressing expired meters, this reduces the risk of the meters failing and ensures the continued delivery of reliable and accurate bills.

vi. Information Used to Justify the Investment: New meter installations are mandatory investments arising from customer requests for new service connections, therefore customer requests are the source of information used to justify the new meter installations. EPLC continuously monitors the condition and effectiveness of its metering infrastructure. Much of the AMI 1.0 infrastructure has or is reaching its end of life and requires replacement. In addition many meters are due for reverification in the forecast period. This data informed the decision-making process for both the metering verification and the AMI 2.0 project.

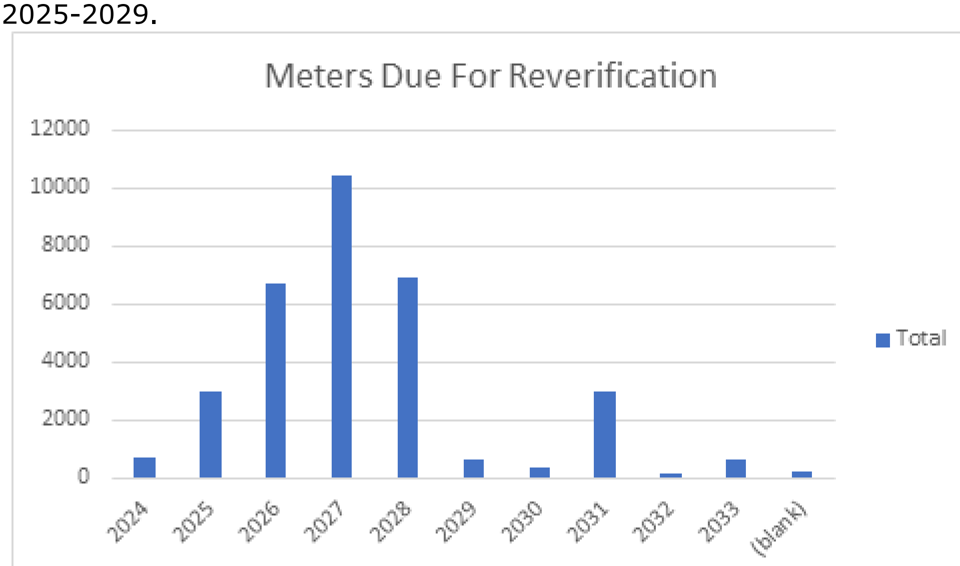
a. Age Distribution of Meters: EPLC considers the Useful Life of standard meters as 15 years. The OEB commissioned Asset Depreciation Study prepared by Kinectrics Inc., also found that the appropriate useful life for smart meters was in the range of 5-15 years, for repeaters 10-15 years, and for collectors 15-20 years. Further, the Ontario Auditor General, in its report on Ontario's smart meter initiative, also found the useful life for a typical first-generation smart meter was 15 years. Over 71% of EPLC's meters are at or approaching their Useful Life within this next rate period. The table below details the age distribution of meters as of 2024.



b. Since 2014, EPLC has experienced an increased trend in annual meter failures, with an annual failure average increasing to 593 meters since 2016, as the AMI 1.0 meters have approached their end of useful life, and we expect this trend to continue until the meters are replaced with new meters.



c. Meter Reverification: Measurement Canada requires LDC's to reverify meters individually or in sample groups to ensure valid accuracy standards are maintained. From 2025 – 2029, EPLC has a significant number of meters due for reverification. Over 84% of EPLC's meters are due for reverification between 2025-2029.



d. Regulatory Compliance Considerations:

Electricity Gas and Inspection and Weights and Measures Acts

The Electricity and Gas Inspection Act, 2004 requires all meters be verified through a sampling program at specified intervals in order to ensure a customer's electricity usage is metered accurately. Once a meter seal expires, the meter cannot legally be used for billing purposes and must either have its seal period extended through compliance sample testing or be replaced. Approximately 84% of the total meter population will have their seals expire between 2025 and 2029 and require compliance sample testing (involving testing a smaller sample group as per Measurement Canada specifications). As a result, in the absence of

intervention, sample testing will need to occur on 65% of the meter population that will have reached or exceeded the end of their service life. This poses a risk of potentially needing to replace thousands of meters with obsolete AMI 1.0 technology should a sample fail.
The Electricity Gas and Inspection Act also requires meters be kept in a condition of "good repair" and the Weights and Measures Act and related regulations require devices be maintained in proper operating condition. In this regard and as discussed above, the meter population has begun to show conditions of disrepair including LCD failures. As meters age beyond their designed service life and deteriorate due to age and environmental conditions, there is an increasing risk of non-compliance with good repair provisions of the Electricity Gas and Inspection and Weights and Measures Acts, and related regulations.

Ontario Standard Supply Service Code and Distribution System Code

The OEB Standard Supply Service Code, 2020, together with the OEB Distribution System Code, set out the obligations EPLC must meet in regard to billing retail customers. In this regard, EPLC is obligated to bill its customers based on their rate plans, and must issue customers no more than 2 estimated bills every 12 months, and issue an accurate bill 98% of the time on a yearly basis. The DSC defines an accurate bill as a bill that contains correct customer information, correct meter readings, and correct rates. A bill is considered inaccurate if: a) the bill has been issued to the customer and subsequently cancelled due to a billing error; or b) there has been a billing adjustment in a subsequent bill as a result of a previous billing error. Billing accuracy, as defined above, is a function of the general performance of the AMI network overall, the number of individual meter failures (and the impact of those individual meter failures on neighbouring meters due to the nature of the mesh network), and the related ability to replace meters and/or perform unscheduled manual meter reading in time to avoid an estimated bill. As meter failures continue to increase as discussed above, and the associated volume of field work in replacing individual meters and unscheduled manual meter reading continues to increase, the risk of inaccurate bills and non-compliance with DSC billing reliability standards will also increase without significant intervention.

3. Investment Justification

i. Demonstrating Accepted Utility Practice*:* For new connections or service upgrades, EPLC plans and executes its metering program to accommodate customer requests and comply with regulations. All new meters installed comply with the latest standards and regulations, and all metering services will be carried out in accordance with EPLC's standards and practices. Meter changes due to customer concerns about meter inaccuracy, and for meter seal life are driven through Measurement Canada.

ii. Cost-Benefit Analysis: This is not applicable.

iii. Historical Investments & Outcomes Observed: The historical costs and number of meters purchased during the historical period are detailed in sections A3 and A5 of this document. Through its metering program, EPLC has been able to continue to meet customer requirements, comply with relevant regulatory requirements, and accurately and correctly measure and bill customers for the electricity that they use.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.32 A. GENERAL INFORMATION ON THE PROJECT/PROGRAM

1. OVERVIEW

This investment program pertains to the continuation of the installation of devices that will enable real-time troubleshooting for unexpected events in the grid.

The investments facilitate the incorporation of:

- Remote fault indicators,
- Reclosers/smart switches,
- Smart grid, renewable expansions and generation, and
- Other associated equipment and resources required for their design, configuration, and installation within EPLC's distribution system.

The primary objective of these initiatives is to mitigate interruptions associated with its infrastructure. ELPC strategically intends to deploy reclosers at key points across its distribution system, aiming to enhance the overall reliability and efficiency of the network and minimize disruptions. With the implementation of smart reclosers, EPLC is facilitating the capabilities of remote operation, real-time outage detection as well as the ability to isolate itself from an upstream distributor/transmitter. Further, incremental data about EPLC's distribution system is gathered and fed into the SmartMAP toolset. Many of these devices are critical in not only improving reliability and efficiency but also modernizing EPLC's grid to enable it to become a distribution system operator (DSO).

Over the planning horizon, the costs of the initiative are expected to total $4.3M. For the 2025 test year this includes the following projects:

- Three-phase recloser installations,
- Single-phase recloser installations,
- Replacement of existing line monitors,
- Replacement of MVI's with smart switches,
- SCADA commissioning of three-phase reclosers, single-phase recloses, DER transfer trip, wholesale meters, smart switches, and line monitors, and
- Automation of Distribution Automated Controller.

In 2021, EPLC was a successful applicant in Natural Resources Canada's Renewable (NRCAN) Energy and Electricity Technologies- Smart Renewables and Electrification Pathways Program (SREP), and as such, has received a grant totalling $1,500,313 to further implement its Self-Healing Grid project. Contributions from SREP have helped accelerate the Self-Healing Grid project, with the ability to install increased reclosers and line monitors within EPLC's distribution system. Additionally, EPLC is using the funding to explore DAC configuration, remote relay control, transfer trip schemes, improve last gasp data flow, and carry out other relevant installations and configurations as required to ensure the Self-Healing Grid achieves its intended goals. This funding is considered in the project, as the contribution agreement with NRCan remains active until March 2025. The costs outlined below exclude the NRCAN funding.

2. TIMING

i. Start Date: 2025
ii. In-Service Date: 2025-2029

iii. Key factors that may affect timing: The below listed factors can impact the timing of the proposed investments:
- Resource constraints;
- Supply chain issues;
- Project prioritization; and
- Overall budget constraints.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	375	374	387	361	615	911	1,473	1,300	722	741	756	776
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	375	374	387	361	615	911	1,473	1,300	722	741	756	776

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

Historical costs have varied year over year in accordance with specific needs identified and works undertaken. Due to the nature of the projects within this program and the fact that works are completed on an as-needed basis, there are no good cost comparators available, and a comparison of historical projects and future projects is not indicative of any particular trend.

6. Investment Priority

This investment is considered to be of high priority. The investments in this program will help support the modernization of EPLC's grid and support its transition to become a DSO.

Out of eighteen (18) material projects/programs planned in the 2025 Test Year, this program was ranked 2nd based on its Risk/Strategic Objective Score, as shown in Table 5. 4-15 of EPLC's DSP.

7. Alternatives Analysis

i. **Do nothing**: Inaction is not a viable option. The proposed investments will modernize EPLC's grid infrastructure and improve safety, reliability, and efficiency. While deferring investment may not have immediate consequences, it will impact EPLC's operations in the long-term through increased vulnerability to disruption that may require more costly remedial efforts.

ii. **Carry out the proposed pacing of investments:** This is the preferred option as it allows EPLC to continue to support its operations. EPLC evaluates the identified needs to determine which are most critical to undertake and which can be monitored and pushed out to later years. Project-specific alternatives are considered on a case-by-case basis depending on the identified need.

8. Innovative Nature of the Project

This is not applicable.

9. Leave to Construct Approval

This is not applicable.

5.33 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	Self-healing grid infrastructure will improve operational efficiency within EPLC's power distribution systems. By autonomously identifying and resolving faults, the system will significantly reduce response times and streamline restoration processes, optimizing energy flow and resource allocation.
Customer Value	Customers will benefit from self-healing grid technology. The proactive fault detection and rapid restoration capabilities will result in reduced service interruptions, providing consumers with a more reliable and consistent energy supply. This advanced infrastructure aligns with evolving customer expectations, offering enhanced satisfaction and confidence in the reliability of EPLC.
Reliability	Self-healing grid infrastructure will improve reliability. The proposed investment will improve the system's ability address disruptions. This will minimize downtime, enhance overall network resilience, and contribute to a highly dependable and robust electrical grid.
Safety	The implementation of self-healing grid technology will enhance safety in power distribution. Swift detection and isolation of faults will minimize risks associated with electrical failures, ensuring a safer environment for both EPLC personnel and consumers. The proactive nature of the system will contribute to early intervention, mitigating potential hazards.

2. Investment Need

i. Main Driver*:* System operational objectives - The installation of self-healing grid infrastructure will enhance reliability and safety by reducing the likelihood and impact of outages, improving response time in the event an outage occurs, and consequently exposing personnel to fewer risks when addressing events.

ii. Secondary Drivers: Cost Effectiveness – The new equipment will reduce downtime, enabling EPLC to better meet the expectations its customers have of their service providers.

iii. Information Used to Justify the Investment: EPLC continuously monitors the condition and effectiveness of its systems using key metrics including:

a. Reliability statistics (SAIDI, SAIFI, CAIDI, etc.).
b. Renewable energy and DER penetration.
c. Improved asset utilization and increased operational efficiency.
d. Reduced greenhouse gas emissions.

This data helped inform the decision-making process for undertaking this project.

3. Investment Justification

i. Demonstrating Accepted Utility Practice*:* A utility's core function is the delivery of secure, dependable, and efficient services, and it is standard utility practice to incorporate modern technology that enables this function. Self-healing grid technology is the latest development in a long line of technological improvements that have been readily accepted by the industry.

ii. Cost-Benefit Analysis: EPLC rigorously assesses the costs and benefits of undertaking new projects. This includes analyzing the costs and benefits of implementation, the consequences of deferral, and evaluating multiple quotes when working with other partners, emphasizing both cost-effectiveness and timely delivery. The proposed investment in self-healing grid infrastructure will mitigate the likelihood and impact of outages and disruptions, consequently reducing the costs associated with these events in the long-term.

iii. Historical Investments & Outcomes Observed: EPLC has installed multiple smart reclosers and other smart devices, which has enable them to minimize outage durations and more efficiently manage its grid remotely.

iv. Substantially Exceeding Materiality Threshold: This is not applicable.

4. Conservation and Demand Management

This is not applicable.

5. Innovation

This is not applicable.

5.34 A. General Information on the Project/Program

1. Overview

PowerShare is a project designed to demonstrate the ability of a Local Distribution Company (LDC) to assume Distribution System Operator (DSO) market functions through a scalable market design to activate Distributed Energy Resources (DER) flexibility locally. This transformation will allow DER owners to monetize their investments by selling surplus or stored generation to bolster grid resilience using NODES market platform.

The project aims to tap into existing DER flexibility and encourage additional flexibility in the distribution grid, serving as a non-wires alternative (NWA). The project also considers regional and provincial grid systems for market participation and simulation to showcase Transmission-Distribution (T-D) coordination between DSO and the Independent Electricity System Operator (IESO) markets.

The pilot project is set to address two significant issues or barriers. First, it will tackle local constraints on EPLC's grid specific to its services in Leamington. Second, it will eliminate existing barriers associated with DERs and their potential impacts on distribution system assets and market participation. Furthermore, the project will test the coordination of DSO/IESO markets, contributing to the resolution of grid constraints at local, regional, and provincial levels.

PowerShare has received funding from the IESO's Grid Innovation Fund and regulatory support from the OEB's Innovation Sandbox through their joint targeted call. As a result, this is the most opportune time to invest in grid modernization and possible DSO activities to realize solutions and outcomes that will help solve Ontario's energy and economic development constraints.

To achieve the DSO model through PowerShare, measurement and verification equipment and associated design and engineering activities were investigated and included in the project costs. The implementation of this equipment will help facilitate running the Local Energy Market during the pilot project to address local constraints. A list of costs during the pilot and forecast period are below:

Category	2025	2026	2027	2028	2029
	($)				
DSO Activities	150,304	153,310	156,377	159,504	162,694

DSO activities include adding hardware for connectivity, integrating the market platform with EPLC's existing systems, and receiving consulting services from project partners to assist in the development of the DSO environment and market participation rules.

Specifically in 2025, these costs include equipment (meters and/or other devices), labour and truck time to install meters and other devices, as well as the associated necessary materials to bring the devices into service. Costs are estimated based on an average of several options for type of equipment and installation and an average number of expected installations. The inputs to the forecast annual investment in DSO are detailed below:

Installation types and associated costs:

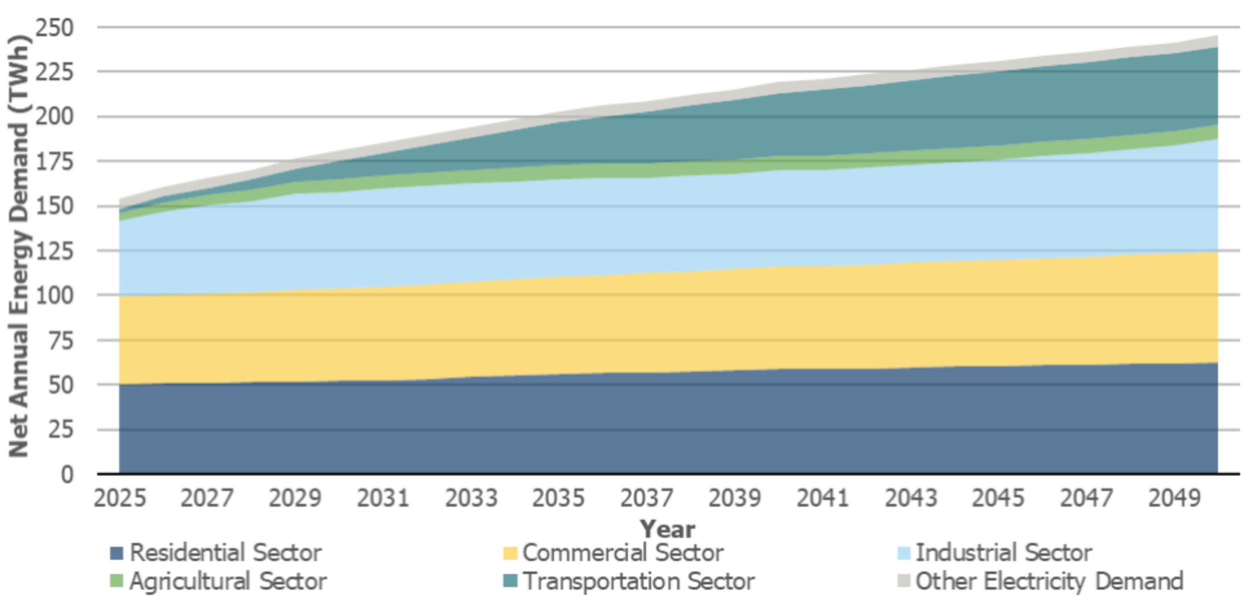
Metering	$ 1,331
OH + 1 Pole + Buss	$ 21,661
OH Close	$ 18,320
OH + 3 Pole + Buss	$ 25,988
UG Close	$ 7,307
OH + UG + Buss	$ 12,295
UG + 1 span	$ 14,258
UG + 2 span + Buss	$ 21,239
OH & UG + Pole + Buss	$ 16,256

EPLC anticipates connecting approximately 6 DSO participants in 2025 to support the testing of Local Energy Market operations as part of the DSO during the pilot phase. EPLC fully expects that the costs listed above will continue to be incurred whether through the testing of its PowerShare DSO market, or through another similar type of local energy market that is operating and leveraging local flexibility in Ontario.

Investments for the project will continue to provide value as policy framework and the provincial energy market evolves to incorporate DSO or similar activities.

The Need

Numerous reports have pointed to the need for LDCs to assist in the energy transition and find innovative ways to meet customer demand while maintaining a clean, reliable, and affordable energy system for the future. Customer expectations are evolving to become prosumers in the energy market, with the expectation to connect EV chargers and related DERs to the distribution system in a timely and efficient manner. According to the IESO's Annual Planning Outlook published in March 2024, Ontario's annual electricity consumption is forecast to increase from 144 TWh in 2023 to 245 TWh in 2050.



Source: IESO Annual Planning Outlook

Similarly, in July 2023, Ontario released its Powering Ontario's Growth report, outlining actions the province is taking to meet increasing demand for electricity driven by strong economic growth and electrification through the 2030s and 2040s. In November 2023, the Ministry of Energy provided a renewed Letter of Direction highlighting the government's priorities for the energy sector, which included housing, transportation and job creation, facilitating innovation within Ontario's Regulatory Framework, planning for EV uptake, and testing DERs within future utility business models, among other significant actions that must be taken.

EPLC's PowerShare project is a cornerstone in the energy transition due to its ability to test and investigate clean energy methods and utility models to achieve some of the constraints and issues highlighted in the abovementioned reports. As mentioned in the Letter of Direction, DERs are critical connectors in a clean energy economy and pose a significant opportunity for innovation across the electricity system. EPLC is exploring how DER technologies can be used as a cost-effective alternative to conventional electricity infrastructure through a DSO model. This project studies and tests local market opportunities for DERs, as well as T-D coordination protocols to further meet regional and provincial market needs as well.

2. Timing

i. Start Date: 2025
ii. In-Service Date: 2025-2029
iii. Key factors that may affect timing: The below listed factors can impact the timing of the proposed investments:
- Resource constraints;
- Supply chain issues;
- Project prioritization;
- Regulatory Modernization, and
- Overall budget constraints.

3. Historical and Future Capital Expenditures

	Historical Costs ($ '000)						Bridge Year	Test Year	Future Costs ($ '000)			
	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Capital (Gross)	0	0	0	0	0	260	372	150	153	156	160	163
Contributions	0	0	0	0	0	0	0	0	0	0	0	0
Capital (Net)	0	0	0	0	0	260	372	150	153	156	160	163

4. Economic Evaluation (Expansion Projects)

This is not applicable.

5. Comparative Historical Expenditure

PowerShare is a unique initiative to EPLC. Due to the nature of this project, there is no good cost comparators available.

6. Investment Priority

The PowerShare DSO project is of medium priority. Out of eleven (11) material projects/programs planned in the 2025 Test Year this program was ranked 10th based on its Risk/Strategic Objective score, as shown in Table 5.4-15 of EPLC's DSP. While deferring the investment does not pose a direct safety or operational risk, it is imperative for future-proofing and modernizing the grid. Additionally, funding has been obtained through the IESO's Grid Innovation Fund and OEB's Innovation Sandbox to help support the project. A total contribution of $3,882,389.10 has been allocated to execute the project and continue to work towards grid innovation practices. As such, this project is critical for understanding and testing DSO functionality in a regulated environment and enabling the future deployment of grid modernization activities.

7. Alternatives Analysis

i. **Do nothing:** Inaction is not a prudent option. The availability of project funding for PowerShare through the Grid Innovation Fund is a critical opportunity to explore the feasibility, application, and use of distribution-connected distributed energy resources. Learnings and insights afforded from undertaking these activities will inform the development of DSO activities at the Distributor, and potentially in the Ontario Market as a whole. Failing to capitalize on non-wires solutions to address capacity challenges in EPLC service territory introduces the risk of increased future capacity needs requiring wires alternatives and the associated investment will be necessary in the near term instead of being managed and deferred.

ii. **Carry out the proposed pacing of investments:** This is the preferred option as it allows EPLC to continue to support its operations and to test LDC performance as a distribution system operator, to operationalize non-wires alternatives within the distribution system and promote grid modernization solutions. EPLC evaluates its identified needs to determine which are the most critical to undertake and which can be monitored and pushed out to later years. Additionally, according to the IESO's Annual Outlook covering Ontario's needs from 2025-2050, daily usage patterns are changing as consumers embrace EVs, industries electrify, and greenhouses increase production. Total provincial demand will increase by 60% over the next 25 years, with the expectation of becoming a dual peaking region with summer and winter peaks comparable at 27,000 MW. While some transmission reinforcements have been identified for the region, there is still a need to enable future reliability and achieve economic and decarbonization goals. PowerShare is opportune for exploring the feasibility, application, and use of non-wires alternatives in a local energy market, potentially mitigating the need to add additional power via large build-out costs, such as bulk transmission systems.

8. Innovative Nature of the Project

The ultimate goal of the PowerShare DSO project is to provide a scalable market design for activation of DER flexibility in near real-time, demonstrating the ability of an LDC to act as a DSO. This will help define the future of the distribution sector, frame the utility of distribution-connected resources in addressing or deferring grid capacity needs, achieve conservation and demand management goals, and provide a platform for the economic integration of electrified resources while creating a more reliable and resilient grid.

PowerShare is distinct from previous distribution-level energy market-like projects, particularly in the manner of scale and market design. PowerShare is an open bidding platform where sellers define their availability for energy and capacity services without a cap on activations or dispatch events. It is designed to maximize flexibility of distribution-level resources, recognizing the varied nature of assets, availability, and that energy service provision is not a core element of the owners' business. PowerShare seeks to demonstrate an order of magnitude greater than previous market-like projects with 5,000 MWh between capacity and energy products. An additional goal is to facilitate a community of Flexibility Service Providers which engages customers beyond a time-limited demonstration.

The PowerShare project is set to enable customer choice in electrification by allowing value-stacking of DER and energy management investments by participating in energy markets, as well as test and provide meaningful inputs in efforts to develop Transmission-Distribution market coordination protocols such as those underway with the IESO's Transmission-Distribution Working Group.

In summary, elements of innovation include, but are not limited to:

- Test Distribution System Operator functionality in a local energy market.
- Enable consumer choice in electrification and allow value-stacking of DER and energy management investments.
- Utilizing non-wires alternatives to solve local constraints, mitigating the need for large build out costs of power systems.
- Test Transmission-Distribution market coordination protocols.
- Support grid modernization initiatives through upgrading infrastructure, implementing smart grid technologies, and integrating renewable energy resources.

9. Leave to Construct Approval

This is not applicable.

5.35 B. Evaluation Criteria and Information Requirements

1. Efficiency, Customer Value, Reliability & Safety

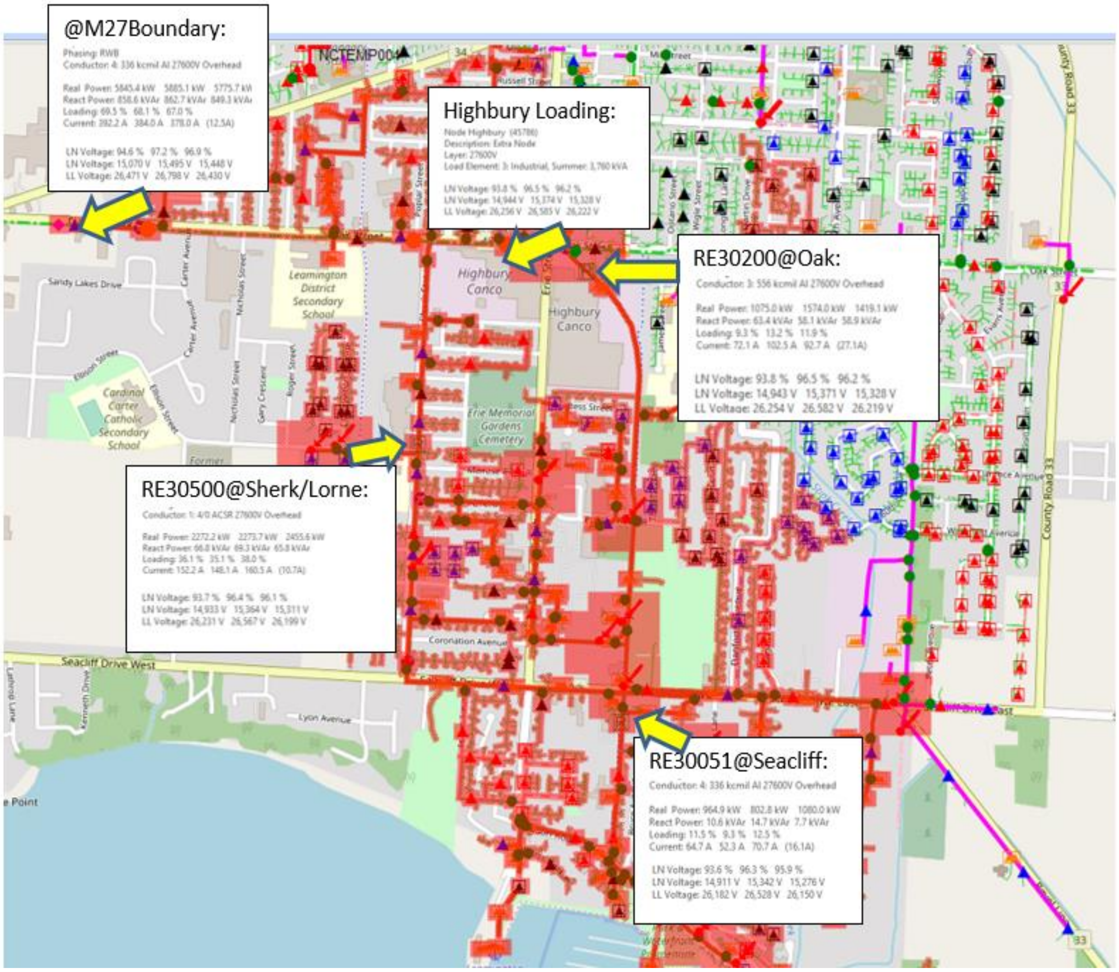
Primary Criteria for Evaluating Investments	Investment Alignment
Efficiency	EPLC will be able to evaluate cost and fitness of distribution services from DERs relative to traditional wires investment and ultimately provide more efficient allocation of resources through optimized use of existing resources (via peak demand management, etc.).
Customer Value	PowerShare will bring value to customers by providing them with access to participate in a local energy market and monetize their existing distributed energy resource assets. Additionally, this project aligns with evolving customer expectations to connect, operate, and eventually commercialize DERs, which offers enhanced satisfaction and confidence in the reliability of EPLC. The project also has the potential to defer large infrastructure investments by allowing LDCs to utilize

	existing NWAs to solve existing grid constraints. This would result in direct benefits for customers.
Reliability	The reliability of EPLC's services is bolstered through PowerShare's availability of energy and capacity service options. EPLC will be able to proactively identify and address potential issues by dispatching DERs, avoiding potential risk in and improving overall system reliability. PowerShare will help in minimizing downtime and improving overall system reliability through utilizing non-wires alternatives solutions to solve known grid constraints.
Safety	EPLC will see overall safety benefits for both its customers and employees through its PowerShare project. PowerShare will help increase system reliability, which will ultimately reduce truck roll outs and outages for customers. By having more reliable power, EPLC will inherently be creating a safer environment for both consumers and employees.

2. Investment Need

i. Main Driver*:* **System Operational Objectives** - Increased Reliability, Capacity and Capability. In parallel with Ontario, EPLC's service territory is experiencing rapid growth demands as the economy grows and, more specifically, as the agriculture sector expands. LDCs across Ontario are looking to adopt new strategies and investments in grid enhancements to improve capacity of the distribution system. EPLC, through the IESO's Grid Innovation Fund and OEB's Innovation Sandbox, has received funding to test and perform as a DSO to unlock benefits of non-wires alternatives and reduce constraints of its local (and provincial) grid.

Through the project, EPLC has determined local grid constraints in the Municipality of Leamington. The Municipality of Leamington has a diverse economy, with a focus on agriculture and manufacturing. Approximately 60% of Ontario's greenhouses can be found in the Leamington area. The high concentration of greenhouses in Leamington account for a significant amount of required load. EPLC currently has access to two feeders (M24 and M27) that service the Leamington community. During high producing months (approximately 6 months of the year), the load on the M27 feeder exceeds a comfortable level (greater than 50%). This limits EPLC's ability to transfer this load to the other feeder in the event of a failure. Existing measures to mitigate issues include requesting access to an additional feeder from Hydro One, however, there are constraints and barriers to this process. As such, EPLC has recognized the Leamington area as a prime location to test its PowerShare project and help alleviate the need to access additional feeder(s) by providing EPLC with the ability to utilize generation from participating DERs to shift loads accordingly and mitigate potential loss of supply or other failures.



By testing the ability for LDCs to act and operate as a DSO in a known constrained area, EPLC is unlocking the potential of utilizing and integrating customer DERs to enhance grid reliability. This is crucial for meeting capacity needs and unlocking economic development opportunities, while mitigating or deferring large build out costs for power systems.

ii. Secondary Drivers*:* Grid innovation to assist in the energy transition and enable electrification, housing growth, and ultimately, increased economic development.

PowerShare hones on the ability to enable technologies that enhance grid reliability and increase capacity and capability of LDCs to accommodate for increased electrification and DER uptake. The project tests using local energy markets and customer-driven DERs to solve local grid constraints, avoiding capacity costs such as electricity transmission and distribution infrastructure costs. According to the Ministry of Energy's Letter of Direction released in November 2023, the facilitation of innovation to meet electrification and energy transition needs is crucial. In July 2023, Ontario released its Powering Ontario's Growth report, outlining actions the province is taking to meet increasing demand for electricity driven by strong economic growth and electrification through the 2030s and 2040s. EPLC believes that LDCs are at the forefront of this energy transition, as they are the closest touchpoint to customers and have a wealth of information and data to support customer needs and growth. Projects like PowerShare enable reliable, clean, and affordable energy, while mitigating capacity costs and providing additional methods for increased economic growth.

iii. Information Used to Justify the Investment*:* Please refer to Part A Section 3-Investment Justification below.

3. Investment Justification

i. Demonstrating Accepted Utility Practice*:* The proposed investments are designed to address reliability performance and grid constraints through grid innovation methods. The investments also enable customer choice as it relates to electrification and integration of DERs, increased economic growth, and other broader societal benefits, such as the reduction of carbon emissions. Since the project is innovative in nature, there are no historical expenditures that can be used in a comparative model at this time. Investments to help establish PowerShare include, but are not limited to, software upgrades, in-field upgrades, market platform integration and API integration with existing utility tools (such as EPLC's GIS platform, SmartMAP), and control room enhancements. EPLC, understanding its local constraints and capacity needs, has strategically planned the PowerShare project to improve grid reliability and enable customers to retain value of their DER assets through a participatory market model. PowerShare is a grid modernization effort that will enable the procurement of safe, reliable, and efficient services to its customers.

ii. Cost-Benefit Analysis**:** EPLC rigorously assess the costs and benefits of undertaking new projects. This includes analyzing costs and benefits of implementation, the consequences of deferral, and evaluating multiple quotes when working with other partners, emphasizing both cost-effectiveness and timely delivery.

PowerShare is a unique opportunity for EPLC and its customers because funding has been secured through the IESO and OEB's joint call through the Grid Innovation Fund and Innovation Sandbox. A total contribution of $3,882,389.10 has been allocated to execute the project and continue to work towards grid innovation practices. This funding enables the project to realize outcomes and provide further analysis on the feasibility of DSO activities within local energy markets. Key benefits of the project include:

a. Enhanced grid modernization
b. Increased reliability via grid management and utilizing existing DERs to meet capacity needs.
c. Reduced capacity spend on large build out costs, such as transmission equipment.

iii. Historical Investments & Outcomes Observed: Grid modernization investments that were made within EPLC's distribution system in the past that also help support a DSO model include:

a. Enhanced engineering analysis capabilities supported by daily meter data.
b. Invested in and improved data quality with upgrades and implementation of industry software such as SmartMAP, GIS, DESS, HealthMAP, etc.
c. Incremental improvements to asset management planning.
d. Created a "self-healing grid" through the implementation of smart technology in the field (such as line monitors and reclosers)

e. Investments in systems and software that permit ongoing improvements to distribution system analytics.

iv. Substantially Exceeding Materiality Threshold: The PowerShare project does not substantially exceed EPLC's materiality threshold.

4. Conservation and Demand Management

For EPLC. CDM activities are a significant consideration in the Distributor's approach to the energy transition and the associated impacts of electrification, decarbonization mandates, and increasing constraints on the local distribution system.

As previously mentioned, EPLC was a successful applicant in response to the IESO and OEB's Joint Targeted Call for innovative projects focused on deriving value from distributed energy resources. EPLC's PowerShare project is primarily aimed at alleviating known constraints on the distribution system. Included in the scope of the project and associated funding are proposed payments to local DER owners for power procured to address local constraints. The pilot project estimated that EPLC would procure up to 5,000MW of electricity over the course of two project phases spanning approximately 24 months. Alternatively, through project activities, EPLC may pay large users of power to curtail load to alleviate constraints. Project funding is to be used to directly support these activities.

Project Deferrals: Since PowerShare is a pilot project funded through the IESO's Grid Innovation Fund and supported by the OEB's Innovation Sandbox, the pilot will be complete in the 2025 test year of EPLC's cost of service application. Investments for the project will continue to provide value as policy framework and the provincial energy market evolves to incorporate DSO or similar activities. EPLC will investigate the deferral of large build-out costs during the remainder of the pilot project period.

Cost-Benefit Analysis: EPLC is testing DSO models to determine the cost-benefit analysis of deferring large build out costs, such as new transmission systems and procuring power from existing DERs within its service territory. The cost-benefit analysis will be an outcome of the overall project and will be used to further analyze the viability of continuing the project after the forecast period.

Use of Advanced Technology**:** There are many components to having a modernized grid that can support the DSO model. Over the past 10 years, EPLC has been working towards upgrading its distribution system to build upon and support different utility business models that enable DERs as NWAs. Some of the previous projects that help advance the DSO model include but are not limited to, upgrading to become a single voltage utility, enabling a self-healing grid through the installation of line monitors, reclosers, and DAC control, enhancing SmartMAP to include algorithms that detect DER and EVs within its service territory, and more. In addition, planned projects within EPLC's current DSP will help improve its ability to operate in a DSO environment. These projects include shared control room services, analyzing and installing AMI 2.0 where deemed necessary and appropriate, and increased upgrades to its self-healing grid project. Each of these projects consider advanced technologies such as:

Molded Vacuum Interrupters (MVI)- operational cubicle upgrades to MVIs replacing the manual isolation and switching procedures with mechanical switches that automatically send status data to a SCADA system. MVIs facilitate real-time monitoring, improving decision-making with high granularity data on network conditions, and supports load shifting and balancing.

Reclosers- Three-phase and single-phase reclosers assist in achieving operational flexibility across the network. Reclosers automatically open and attempt to reclose in the event of faults and can be operated remotely, providing valuable telemetry data for SCADA systems.

AMI 2.0- interval meter upgrades leverage the latest technology to offer detailed consumption analysis, improve reliability in communications, and support the enablement of customer-specific reliability measures and system configuration updates. These upgrades improve load flow analysis, provide improved outage management, allow for bi-directional flow, and are more effective for integrating and monitoring DERs.

While these projects act as standalone grid modernization upgrades to enhance visibility and grid reliability for EPLC, they also form necessary investments for DSO functionality.

5. INNOVATION

Please refer to Part A, Section 8

APPENDIX B: 2023 Asset Condition Assessment (ACA) Report

Essex Powerlines Corporation

Asset Condition Assessment Report 2023

Client Document No.: 7850

December 15th, 2023

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Summary

This report relays the findings of an Asset Condition Assessment ("ACA") of the major electrical assets of Essex Powerlines Corporation ("EPLC"). BBA previously developed an asset HI framework for EPLC's assets in August 2017. EPLC engaged BBA to update the ACA based on the latest demographic, testing and inspection data.

This Asset Condition Assessment is based on data compiled up to October 2023 and covers the following assets classes:

- Wood poles
- Concrete poles
- Dip poles (primary risers)
- Pad-mount transformers
- Pole-mount transformers
- Load-break switches
- Switchgear units
- Switching cubicles
- Primary Overhead ("OH") conductors
- Primary Underground ("UG") cables

Table 0-1 summarizes the asset condition assessment criteria and Typical Useful Life ("TUL") for each asset class. The number of assets in each class is summarized in Table **0-2**

Table 0-1: Asset Condition Assessment Criteria and TUL for each Asset

Asset Class	Assessment Criteria	TUL (years)
Wood Poles	Resistograph test results, visual inspection results, service age	45
Concrete Poles	Visual inspection results, service age	60
Dip Poles (Primary Risers)	Visual inspection results, service age	45
Pad-Mounted Transformers	Visual inspection results, service age, IR results	40
Pole-Mounted Transformers	Visual inspection results, service age, IR results	40
Load-Break Switches	Visual inspection results, IR results	45
Switchgear	Visual inspection results, service age	30
Switching Cubicles	Visual inspection results, service age	30
Primary OH Conductors	Service age	60
Direct-buried Primary UG Cables	Service age	30
Primary UG Cables in Conduit	Service age	40

Table 0-2: Number of Assets by Class

Asset Class	Number of Assets
Wood Poles	6,037
Concrete Poles	158
Dip Poles (Primary Risers)	541
Pad-mounted Transformers	1,872
Pole-mounted Transformers	983
Load-Break Switch	66
Switchgear	67
Switching Cubicles	45
Primary OH Conductors	180.4 km
Primary UG Cables	279.0 km

Methodology and Findings

For all asset classes that underwent assessment, BBA used a consistent scale of asset health, containing five categories – from Very Good to Very Poor. The numerical HI corresponding to each condition category serves as an indicator of an asset's remaining life, given as a score from 0 to 100. The HI formulations for individual asset classes represent weighted averages of numerical scores for individual HI subcomponents, known as condition parameters, scored on a scale from 0 to 100. The numerical score ranges, condition categories, and typical characteristics of an asset are described in *Table 0-3*.

Table 0-3: Definition of HI Scores

Score (%)	Condition Category	Description
[85-100]	Very Good	Some evidence of aging or minor deterioration of a limited number of components
[70-85)	Good	Significant deterioration of select components to be managed through normal maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components
[30-50)	Poor	Widespread serious deterioration across multiple components
[0-30)	Very Poor	Extensive serious deterioration – an asset has reached its end-of-life

The relative contribution of various condition parameter scores on the aggregate HI results is a function of weighting – assigned by an engineer to each HI subcomponent prior to commencing calculations. Using this methodology, BBA calculated HI results for every asset class except cable asset classes which will use an age-based replacement plan.

The results of the Asset Condition Assessment are summarized in Figure 0-1 to *Figure 0-3:*. Figure 0-1 shows that the majority of EPLC's assets are in Very Good condition. *Figure 0-2:* and *Figure 0-3:*

present the service age of EPLC's primary OH conductors and UG cables by TUL. TUL results for OH conductors show that 17.9 km are not near TUL. The majority of primary OH conductors are of unknown service age which adds uncertainty to the results. The results for primary UG cables show that 158.4 km are not near TUL, 71.6 km are approaching TUL, and 15.0 km are past TUL.

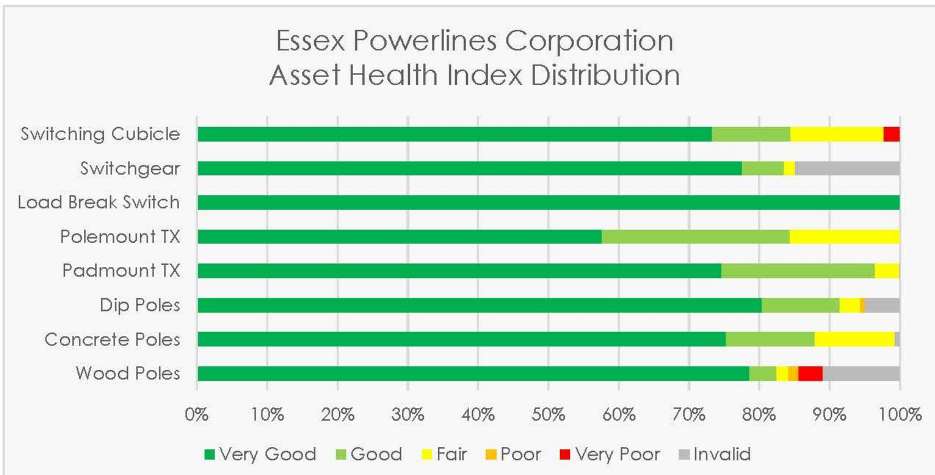

Figure 0-1: Asset HI Distribution

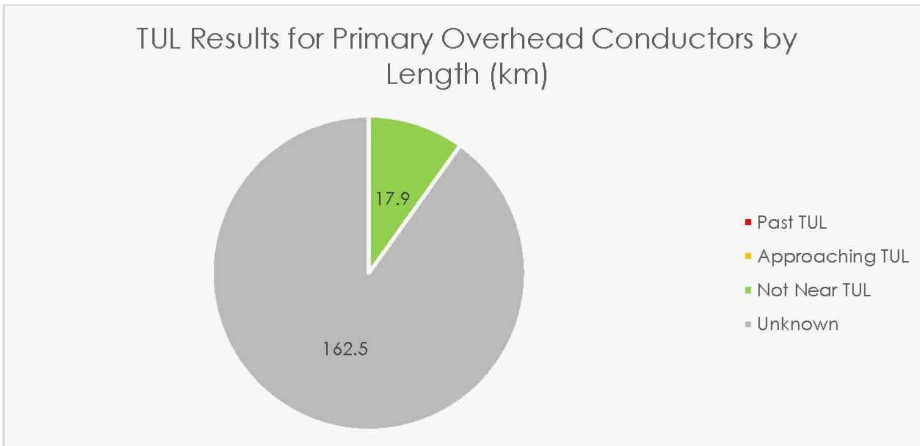

Figure 0-2: Primary OH Conductors TUL Results

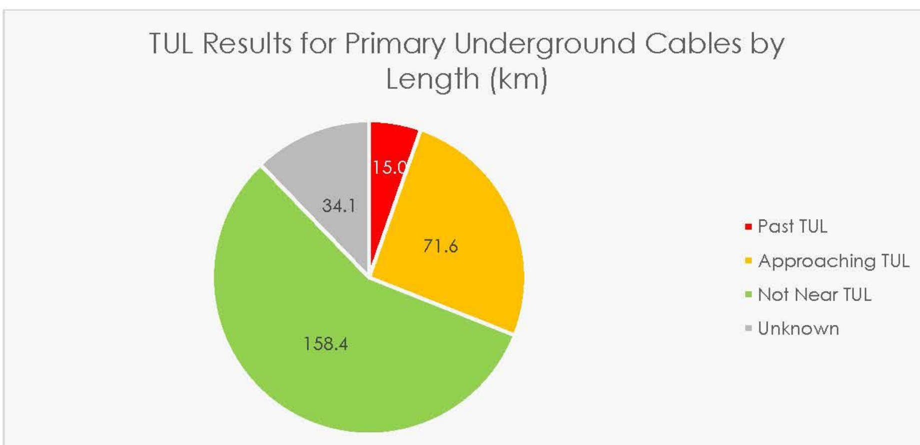

Figure 0-3: UG Cables TUL Results

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LIST OF ACRONYMS

Acronym	Definition
A1-TEC	Tecumseh
A3-LEA	Leamington
A5-AMH	Amherstburg
A7-LAS	LaSalle
ACA	Asset Condition Assessment
AM	Asset Management
AMP	Asset Management Plan
CI	Condition Indicator
DAI	Data Availability Index
EPLC	ESSEX Powerlines Corporation
HI	Health Index
HIF	Health Index Formulation
IR	Infrared
OH	Overhead
OH_COND	Overhead Conductor
OH_TX	Pole-mount Transformer
OH_SW	Load-Break Switch
POLE	Wood, Concrete, and Dip Poles
SWGR	Switchgear
TUL	Typical Useful Life
UG	Underground
UG_CABLE	Underground Primary Cable
UG_SW	Switching Cubicle
UG_TX	Pad-mounted Transformer
W	Condition Parameter Weight

1. Introduction

This report summarizes the results of an Asset Condition Assessment ("ACA") study carried out by BBA on behalf of Essex Powerlines Corporation ("EPLC"). BBA previously developed an ACA for EPLC's fixed assets in August 2017 with the objective of establishing the health and condition of fixed assets employed in the distribution systems. EPLC engaged BBA to update the ACA based on the latest demographic and inspection data.

In preparation of this report, BBA relied on the following data sources:

1. Asset inspection and IR data collected by EPLC staff or external contractors.

2. Past deliverables pertaining to specific undertakings prepared by staff or consultancies.

The Asset Condition Assessment methodology was applied to different categories of fixed assets that are employed in EPLC's distribution system. Adoption of the ACA methodology would require periodic asset inspections and recording of their condition to identify those most at risk, requiring focused investments into risk mitigation. Additionally, computing the HI for distribution assets requires identifying End of Life ("EOL") criteria for various components associated with each asset type. Each criterion represents a factor that is influential in determining the component's current condition relative to conditions reflective of potential failure. These components and tests shown in the tables are weighted based on their importance in determining a given asset's EOL.

The assets classes covered in the report include the following:

- Wood poles
- Concrete poles
- Dip poles (primary risers)
- Pad-mount transformers
- Pole-mount transformers
- Load-break Switches
- Switchgear units
- Switching cubicles
- Primary Overhead ("OH") conductors
- Primary Underground ("UG") cables

2. Asset Health Index Calculation Methodology

ACA is the process of determining an HI, which is a quantitative expression of an asset's current condition. A brand-new asset should have an HI of 100% and an asset in very poor health should have an HI below 30%. Generating an HI provides a succinct measure of the long-term health of an asset. Table 2-1 presents the HI ranges and the corresponding asset condition.

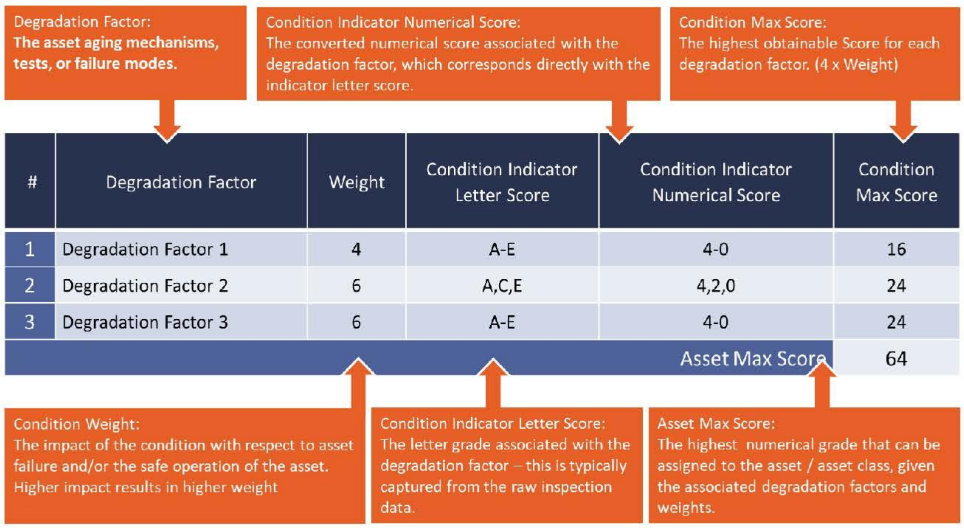
Table 2-1: Definition of HI Scores

HI Score (%)	Condition	Description	Implications
[85-100]	Very Good	Some evidence of ageing or minor deterioration of a limited number of components	Normal Maintenance
[70-85)	Good	Significant Deterioration of some components	Normal Maintenance
[50-70)	Fair	Widespread significant deterioration or serious deterioration of specific components	Increase diagnostic testing; possible remedial work or replacement needed depending on the unit's criticality
[30-50)	Poor	Widespread serious deterioration	Start planning process to replace or rehabilitate, considering risk and consequences of failure
[0-30)	Very Poor	Extensive serious deterioration	The asset has reached its end-of-life; immediately assess risk and replace or refurbish based on the assessment

2.1. Condition Parameters

Condition parameters of the asset are characteristic properties that are used to derive the overall HI. Condition parameters are specific to each asset class. A condition parameter can be comprised of many sub-condition parameters. For example, the oil quality ("OQ") condition parameter of an asset belonging to the station power transformer asset class includes multiple sub-condition parameters such as acid number, interfacial tension, dielectric strength, and water content.

To determine the overall HI for an asset, formulations are developed based on condition parameters that can be expected to contribute to the degradation and eventual failure of that particular asset type. A weight is assigned to each condition parameter to indicate the amount of influence the condition has on the overall health of the asset. Figure 2-1 provides an example of an HI formulation ("HIF") table.



#	Degradation Factor	Weight	Condition Indicator Letter Score	Condition Indicator Numerical Score	Condition Max Score
1	Degradation Factor 1	4	A-E	4-0	16
2	Degradation Factor 2	6	A,C,E	4,2,0	24
3	Degradation Factor 3	6	A-E	4-0	24
				Asset Max Score	64

Figure 2-1: HI Formulation Components

The scale used to determine an asset's score for a condition parameter is called the Condition Indicator. Each condition parameter is ranked from A to E and each rank corresponds to a numerical grade. In the above example, a Condition Indicator of 4 represents the best grade, whereas a Condition Indicator of 0 represents the worst grade. In some cases where there are multiple sub-condition parameters contributing to a single condition parameter, the lowest sub-Condition Indicator is taken as the overall Condition Indicator for that parameter. This prevents deficiencies in an asset's health from being covered up by an averaging process during the HI calculation.

The conversion from alphabetic ranking to numerical grade and a brief character description of the grade is provided in Table 2-2.

Table 2-2: Sample Letter-Numerical Conversion Chart

Letter/Number Grade	Grade Description
A – 4	Best Condition
B – 3	Normal Wear
C – 2	Requires Remediation
D – 1	Rapidly Deteriorating
E – 0	Beyond Repair

2.2. Final Asset Health Index Formulation

The final HI, which is a function of the Condition Indicators and weights, is calculated based on the following formula:

$$HI = \left(\frac{\sum_{i=1} W_i * CI_i}{CI_{max.}}\right)$$

where:

- i corresponds to the condition parameter number within the HI formulation;
- CI_i represents the Condition Indicator as determined from the testing or field-inspection procedure that is associated with condition parameter i;
- W_i represents the relative importance of condition parameter i within the HI based on the impact of the parameter on the asset's overall failure probability;
- CI_{max} represents the highest numerical grade that can be assigned to the asset and is being used to normalize the final HI score between 0% and 100%; and
- HI represents the asset health index as a percentage.

2.3. Asset Health Index Results

An asset's HI is given as a percentage; the HI is calculated only if sufficient condition parameter data for a given asset is available. The subset of the total population with sufficient data parameters is called the sample size. HI results can be analyzed on a per-asset, per-asset-class, or per-system basis depending on the granularity required in the analysis.

2.4. Data Availability Index

The DAI is a measure of the availability of condition parameter data for a specific asset, as they pertain to the construction of the HI score. The DAI is determined by comparing the sum of the weights of the condition parameters available to the total weight of the condition parameters used to construct the HI for an asset class. The formula is given by:

$$DAI = \left(\frac{\sum_{i=1} W_i * \alpha_i}{\sum_{i=1} W_i}\right)$$

where:

- i iterates through the condition parameters within the HI formulation;
- W_i is the weight assigned to condition parameter i;
- α_i represents the data availability coefficient, which is equal to 1 if data is available, and equal to 0 when data is unavailable; and

- *DAI* represents the Data Availability Index as a percentage.

An asset with all condition parameter data available will have a DAI value of 100% independent of the asset's HI score. Assets with a higher DAI will correlate to HI scores with a higher degree of confidence. For an individual asset, the HI was not calculated if the DAI fell below 50%. The average DAI for each asset class is summarized in *Table 2-3* below. Overhead conductors and underground cables were evaluated based on age only, therefore the DAI for these asset classes is not relevant.

Table 2-3: Average DAI by Asset Class

Asset Class	Average DAI
Wood Poles	85%
Concrete Poles	93%
Dip Poles (Primary Risers)	90%
Pad-mounted Transformers	97%
Pole-mounted Transformers	98%
Load-Break Switches	99%
Switchgear	88%
Switching Cubicles	72%

2.5. Data Gaps

The HIFs calculated in this study are based only on available data provided by EPLC. In almost all instances, additional condition parameters or tests exist that can be performed on an asset to further ascertain its state of degradation. In certain cases, condition parameters may be available for one or several assets in a class, but unavailable for others in the same class. This scenario represents a data gap, wherein the planner must determine whether the number of assets for which a particular parameter is available is sufficient to include it in the calculation of the overall HI.

An asset with all condition parameter data available will have a DAI value of 100%, independent of that asset's HI score. Assets with a high DAI will correlate to HI scores that describe the asset condition with a high degree of confidence. The DAI threshold is taken to be 50% throughout this study.

2.6. Use of Age as a Condition Parameter

There is a degree of debate within the electrical utility industry regarding the appropriateness of including age as a condition parameter for calculating asset Health Indices. At the core of the argument against the use of age in assessing asset condition is the notion that age implies a linear degradation path for an asset that does not always match the experience in the field.

While some assets lose their structural integrity faster than would be expected with time, others, such as those with limited exposure to natural environmental factors, or those that benefitted from regular predictive and corrective maintenance, may retain their original condition for a longer time than age-based degradation would imply.

In recognition of the argument as to the limitations of age-based condition scoring, BBA attempts to limit the instances where it relies on age as a parameter explicitly incorporated into the calculation of asset HI. In some cases, however, the limited number of condition parameters available for the calculation of asset health makes age a useful proxy for the important factors that the analysis would not otherwise capture. In other cases, such as when assessing the condition of complex equipment (e.g., power transformers) – which contain several internal mechanical components that degrade with continuous operation and the state of which cannot be assessed without destructive testing – age represents an important component of asset health calculation irrespective of the number of other factors that may be available for analysis.

In the context of the current study, the availability of data on condition parameters varied significantly across asset classes. Where BBA deemed the number of available condition parameters as insufficient to calculate a reliable HI for a particular asset class, and especially where the available information amounted to factors that do not represent the most significant degradation factors for a particular type of equipment, we included age as one of the condition parameters where data was available.

3. Asset Condition Assessment Results

3.1. Health Indices

3.1.1. Wood Poles

Condition Assessment Methodology

Wood poles are the most common asset owned by an electrical utility and are an integral part of the distribution system. Poles are the support structure for OH distribution lines as well as assets such as OH transformers, switches, and reclosers.

Wood, being a natural material, has degradation processes that are different from other assets in distribution systems. The most critical degradation processes for wood poles involve biological and environmental mechanisms such as fungal decay, wildlife damage, and effects of weather which can impact the mechanical strength of the pole. Loss in the strength of the pole can present additional safety and environmental risks to the public and the utility. In the short term (one to three years), the most informative end-of-life criterion is the calculation of remaining strength through pole testing. However, since pole strength tends to fall off quickly as a pole starts to degrade, the preferred predictor over the medium to long term (three to ten years) is age. Generally, poles that are newer than ten or twenty years in service are not tested at all other than by way of visual inspections. A pole that is not yet showing effects of age but exhibits other defects such as large cracks or rot or is out of plumb may also be targeted for replacement.

The HI for wood poles is calculated by considering a combination of service age, visual inspection results, and pole testing results (cavity and decay determined from a Resistograph test). **Table 3-1** summarizes the methodology to combine these criteria into an overall HI for wood poles. The methodology employs a "gateway" if the pole fails the cavity test, forcing the pole condition to be Very Poor by halving the HI. Appendix A provides grading tables for each condition parameter.

Table 3-1: Wood Poles HI Algorithm

Condition Parameter	Weight	Ratings	Numerical Score	Max Score
Cavity Test (Resistograph)*	8	A,B,C,D,E	4,3,2,1,0	32
Decay Test (Resistograph)	6	A,B,C,D,E	4,3,2,1,0	24
Outstanding issues (visual inspection)	4	A,B,C,D,E	4,3,2,1,0	16
Service age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**84**

*If E, divide by HI by 2

Data Collection and Assumptions

EPLC's inspection records, pole asset registry, and resistograph test results were the primary sources of information used to complete the wood poles condition assessment. Pole visual inspections were recorded from 2017-2022. The most recent test result for each asset was used to determine the cavity test and decay test score.

Demographics

EPLC owns 6,037 wood poles across its four service areas. The service age is known for 57% of EPLC's wood poles. Table 3-2 presents the wood poles' age demographics by service area. Leamington and LaSalle have the highest number of wooden poles. Figure 3-1 shows the age distribution of wood poles. EPLC has a larger portion of known poles that are between 0-30 years old.

Figure 3-1 presents the age distribution and Figure 3-2 shows the age demographics by TUL. The TUL for wood poles is 45 years. Wood poles within 15 years of TUL were classified as Approaching TUL. A large proportion of EPLC wood poles are not near TUL. However, since 43% of wood poles are of unknown age there exists a lot of uncertainty in the TUL results.

Table 3-2: Age of Wood Poles by Service Area

Age	Number of Wood Poles by Service Area					
	Tecumseh	Leamington	Amherstburg	LaSalle	Unknown Area	Total
0-10 years	227	249	136	660	0	1,272
11-30 years	148	322	80	563	0	1,113
31-40 years	44	86	37	108	0	275
41-50 years	33	188	6	135	0	362
>50 years	11	292	38	60	0	401
Unknown Age	478	409	357	1,368	2	2,614
Total	**941**	**1,546**	**654**	**2,894**	**2**	**6,037**

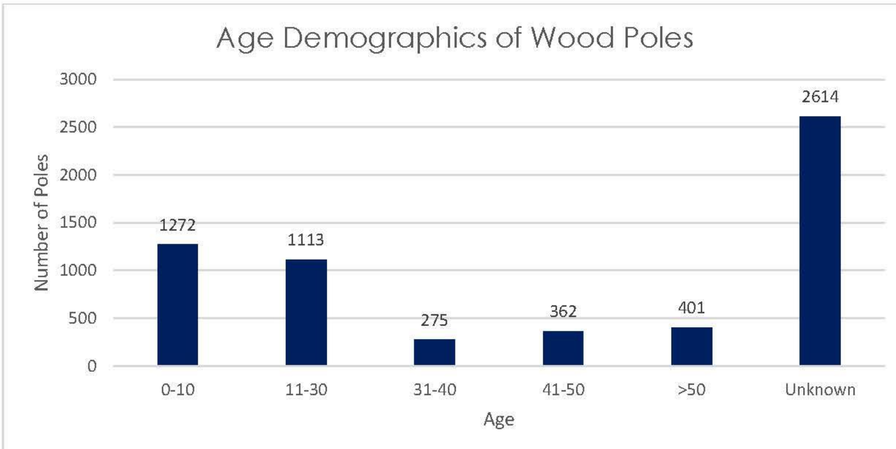


Figure 3-1: Wood Pole Age Demographics

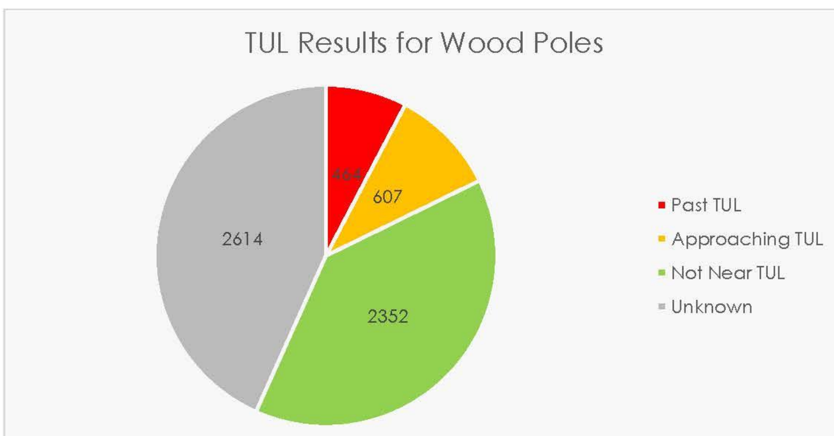


Figure 3-2: Age Summary of Wood Poles by TUL

HI Results

HI results were calculated for 5,375 wood poles and are summarized in Table 3-3 and Figure 3-3 below. If the age is unknown, then the HI is calculated based on the Resistograph test results and the results of visual inspections. Most of EPLC's wood poles are in Very Good condition. There are also 294 wood poles whose condition was identified as Poor or Very Poor which may need to be replaced in the near future.

Table 3-3: Wood Pole HI Results by Service Area

Condition	Number of Wood Poles by Service Area					
	Tecumseh	Leamington	Amherstburg	LaSalle	Unknown Area	Total
Very Good	660	1,146	482	2,459	0	4,747
Good	26	60	51	95	0	232
Fair	17	31	18	36	0	102
Poor	15	13	11	51	0	90
Very Poor	34	68	25	77	0	204
Unknown HI	189	228	67	176	2	662
Total	**941**	**1,546**	**654**	**2,894**	**2**	**6,037**

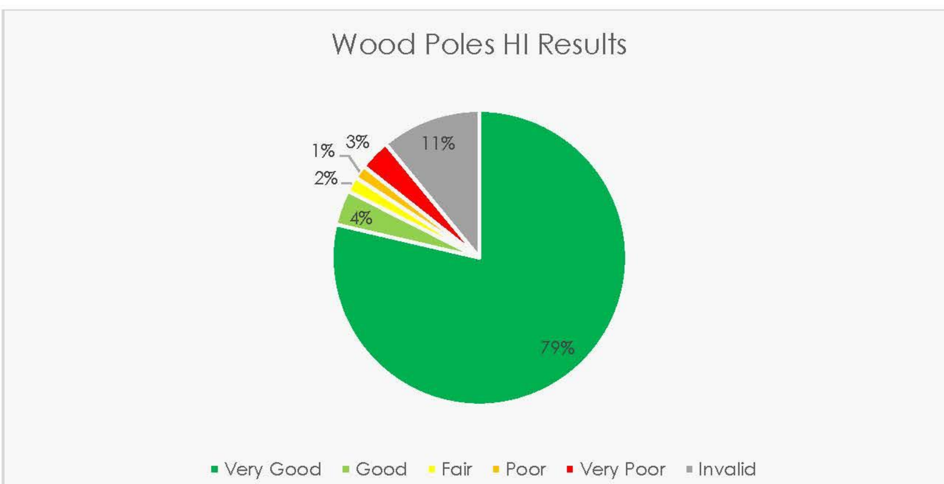


Figure 3-3: HI Results for Wood Poles

3.1.2. Concrete Poles

Condition Assessment Methodology

Concrete poles develop corrosion on the internal reinforcing bars, which expands the iron and displaces the concrete in a process known as spalling. Once spalling begins, poles become weaker and tend to fail over a short number of years. There are limited methods for the long-term repair of a spalled pole. Spalling is accelerated in the presence of road salt. In the short term (one to three years) the most informative indicator is a visual observation of spalling; there is no way to predict that corrosion is occurring inside concrete poles. The best predictor of a need for medium-term replacement (three to ten years) is the age and condition of similar poles.

Table 3-4 below provides the concrete pole two-parameter HI algorithm. The HI for concrete poles is calculated considering both the service age and visual inspection results. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 3-4: Concrete Poles HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Outstanding Issues	4	A,B,C,D,E	4,3,2,1,0	16
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**28**

Data Collection and Assumptions

EPLC's inspection records and pole asset registry were the primary sources used to complete the condition assessment of concrete poles. The visuals inspections data provided by EPLC were conducted between 2017-2022. Service Age was available for 86% of EPLC's concrete poles. Visual Inspection results were available for 99% of concrete poles. The average DAI for EPLC's concrete poles is 93%.

Demographics

EPLC owns a total of 158 concrete poles, across its four service areas. The service age is known for 86% of concrete poles. Table 3-5 presents the age of concrete poles by service area. Table 3-5 indicates that LaSalle contains the most concrete poles. Figure 3-4 presents the age distribution of concrete poles.

Figure 3-5 summarizes the age demographics by TUL. The TUL for concrete poles is 60 years. Concrete poles within 20 years of TUL were classified as Approaching TUL. There have been very few concrete pole installations over the past ten years and most concrete poles are between 11-30 years old. Figure 3-5 shows that 118 concrete poles are not near TUL, 18 concrete poles are approaching TUL, and the 22 concrete poles are of unknown age.

Table 3-5: Age of Concrete Poles by Service Area

Age	Number of Concrete Poles by Service Area				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	0	1	0	3	4
11-30 years	24	7	18	45	94
31-40 years	0	0	0	20	20
41-50 years	0	1	0	16	17
>50 years	0	1	0	0	1
Unknown Age	2	5	9	6	22
Total	**26**	**15**	**27**	**90**	**158**

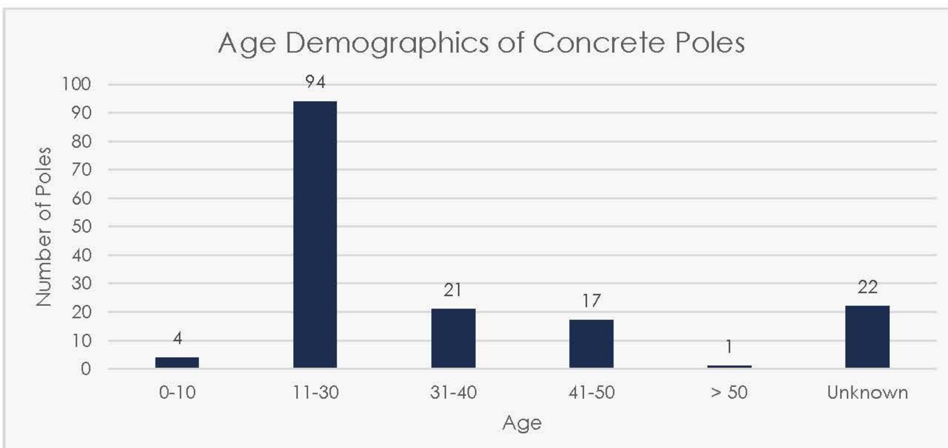


Figure 3-4: Concrete Pole Age Demographics

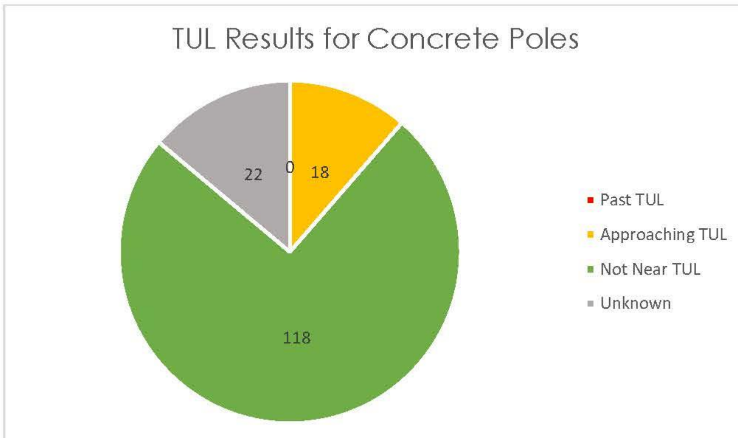


Figure 3-5: Age Summary of Concrete Poles by TUL

HI Results

EPLC owns 158 concrete poles and valid HI results were calculated for 157 of them. If age was unknown HI was calculated solely based on visual inspection results. The HI results for concrete poles are presented in Table 3-6 and Figure 3-6. The majority of EPLC's concrete poles are in Very Good condition. The rest of the valid concrete poles are either in Good or Fair condition.

Table 3-6: Concrete Poles HI Results by Service Area

Condition	Number of Concrete Poles by Service Area					
	Tecumseh	Leamington	Amherstburg	LaSalle	Unknown Area	Total
Very Good	26	12	27	54	0	119
Good	0	0	0	20	0	20
Fair	0	2	0	16	0	18
Poor	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0
Unknown HI	0	1	0	0	0	1
Total	**26**	**15**	**27**	**90**	**0**	**158**

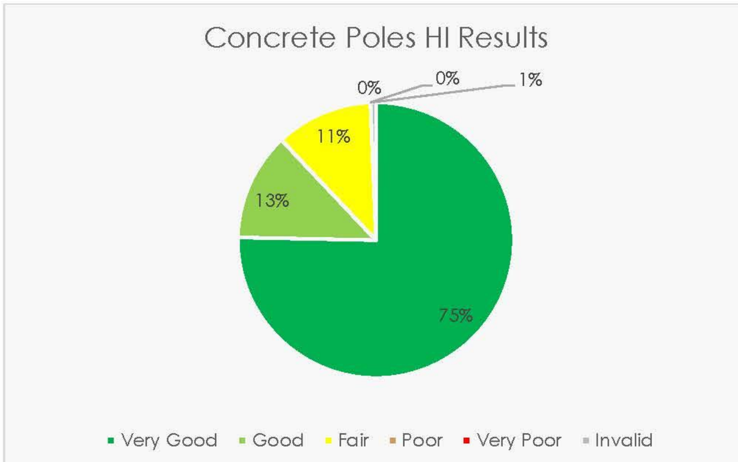


Figure 3-6: Concrete Pole HI Results

3.1.3. Dip Poles (Primary Risers)

Condition Assessment Methodology

Dip poles include protective equipment, cable potheads/terminations, and hardware installed on primary risers (the transition point between the overhead and underground system).

Table 3-7 provides the dip pole two-parameter HI algorithm. The HI for dip poles is calculated using both the service age and visual inspection results. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 3-7: Dip Poles HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Inspection Results	4	B,C,D,E	3,2,1,0	12
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**24**

Data Collection and Assumptions

EPLC's inspection records and dip pole asset registry were the primary sources used to complete the condition assessment of dip poles. The visuals inspections data provided by EPLC were conducted between 2019-2022. Service Age was available for 81% of EPLC's dip poles. Visual Inspection results were available for 95% of dip poles. The average DAI for EPLC's dip poles is 90%.

Demographics

EPLC owns 541 dip poles across its four service territories. The service age is known for 81% of dip poles. Table 3-8 presents the dip poles age demographics by service area. Figure 3-6 presents the age demographics by service area. Figure 3-7 presents the age distribution of Dip Poles. Most of the known dip poles are between 11-30 years old and there are a few number assets between 31-50 years old.

Figure 3-8 provides an age summary by TUL. The TUL for dip poles is 45 years. Dip poles within 15 years of TUL were classified as Approaching TUL. Figure 3-8 shows that 350 dip poles are not near TUL, 82 dip poles are approaching TUL, 4 dip poles are past TUL, and 105 dip poles are of unknown age.

Table 3-8: Age of Dip Poles by Service Area

Age	Number of Poles by Service Area				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	24	23	21	37	105
11-30 years	49	45	17	147	258
31-40 years	14	17	18	11	60
41-50 years	5	5	1	2	13
>50 years	0	0	0	0	0
Unknown Age	19	41	14	31	105
Total	**111**	**131**	**71**	**228**	**541**

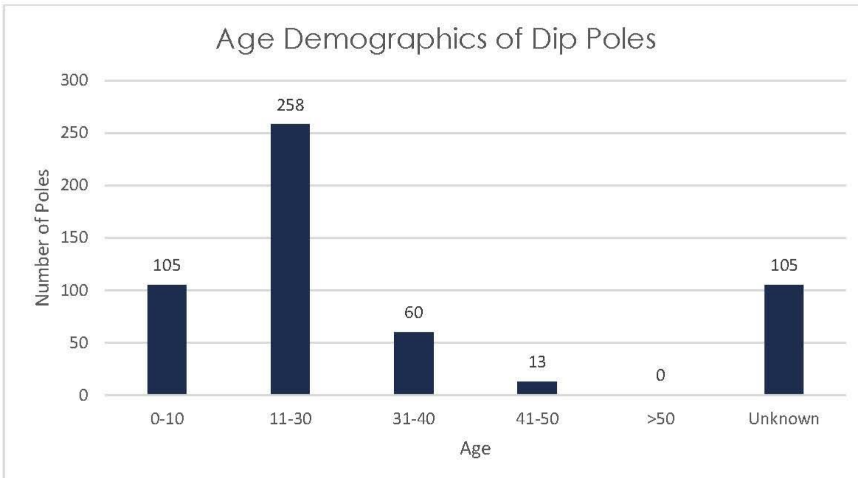


Figure 3-7: Age Demographics of Dip Poles

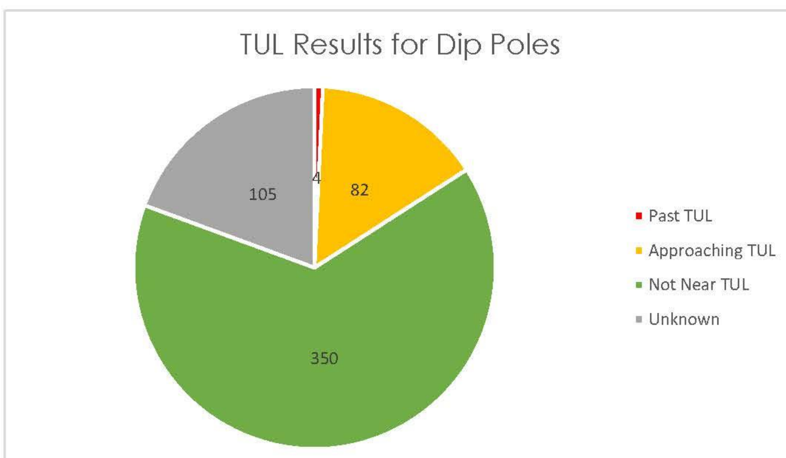


Figure 3-8: Dip Poles Age Summary by TUL

HI Results

Valid HI results were calculated for all dip poles. If service age was not listed the HI was calculated based on visual inspection results. HI results for dip poles are shown in Table 3-9 and Figure 3-9 below. Most of EPLC's dip poles are in Very Good condition.

Table 3-9: Dip Poles HI Results by Service Area

Condition	Number of Concrete Poles by Service Area					
	Tecumseh	Leamington	Amherstburg	LaSalle	Unknown Area	Total
Very Good	84	105	44	202	0	435
Good	14	15	18	13	0	60
Fair	4	6	2	4	0	16
Poor	1	1	0	1	0	3
Very Poor	0	0	0	0	0	0
Unknown HI	8	4	7	8	0	27
Total	**111**	**131**	**71**	**228**	**0**	**541**

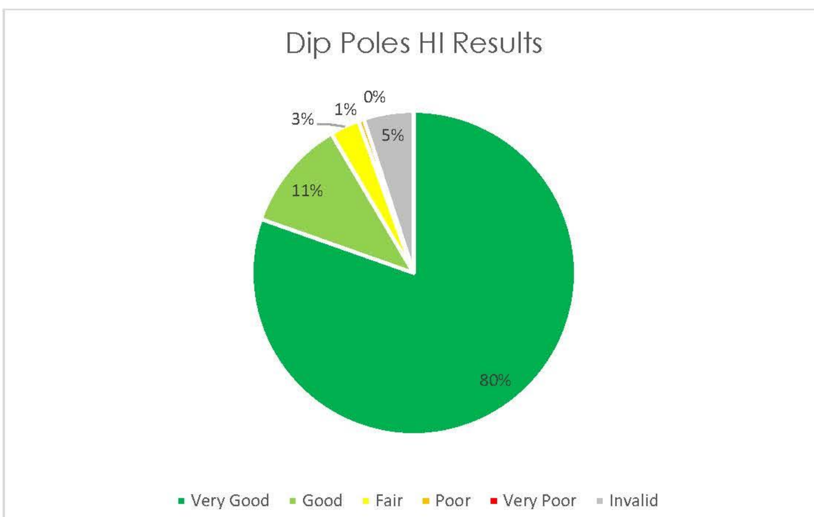


Figure 3-9: Dip Poles HI Results

3.1.4. Distribution Transformers

Condition Assessment Methodology

Transformers are another large asset class within the distribution system. This asset category is made up of a large number of units, each with a modest replacement value. EPLC owns a total of 2,855 distribution transformers across its four service areas, 1,872 transformers are pad-mounted, and 983 transformers are pole-mounted.

Distribution transformers are generally considered to be a run-to-failure asset class with little maintenance other than visual inspections and IR scans. Transformers may be replaced in planned projects based on identifiable degradation, pole line rebuilds, road relocations, or upgrade projects in response to customer load growth.

Transformers typically reach their end-of-life due to physical tank deterioration (e.g., corrosion), which in extreme cases can lead to an instance of leaking oil. Where corrosion is detected, a transformer may be cycled back to the shop and re-painted with gaskets being replaced. Other modes of failure include overheated connections due to loosened connectors, which are typically detected in IR scanning and tightened to reduce the failure risk.

Most commonly, utilities replace distribution transformers as part of OH or UG rebuild projects. Occasionally, a transformer will become overloaded due to changes in customer usage which can be detected by summing loads monitored with automated meter infrastructure and can lead to internal failures if not rectified. The HI values for both pole-mount and pad-mount distribution transformers are calculated by considering a combination of service age, visual inspection results, and IR scan results. *Table 3-10* shows the HI algorithm for distribution transformers. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 3-10: Distribution Transformer HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	3	A,B,C,D,E	4,3,2,1,0	12
Visual Inspection	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	2	B,C,D,E	3,2,1,0	6
			Total Score	**26**

Data Collection and Assumptions

The service age was available for near 100% of pad-mount transformers and 98% of pole-mount transformers. Visual inspection records from 2018 to 2022 were used to determine the asset's overall condition. Visual inspection results were available for 90% of pad-mounted transformers and 96% of pole-mounted transformers. The average DAI was 97% and 98% for pad-mounted and pole-mounted transformers respectively.

Demographics

EPLC owns 1,872 pad-mount distribution transformers across its four service territories. The service age is known for near 100% of EPLC's pad-mount transformers. Table 3-11 presents the age demographics of pad-mount transformers by service area. The majority of pad-mount transformers are in LaSalle.

Table 3-11: Pad-mount Transformer Age Demographics by Service Area

Age	Number of Pad-Mounted Transformers				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	137	107	93	179	516
11-30 years	168	206	147	406	927
31-40 years	123	68	67	122	380
41-50 years	13	20	3	8	44
>50 years	0	0	0	0	0
Unknown	2	0	3	0	5
Total	**443**	**401**	**313**	**715**	**1,872**

Figure 3-10 presents the age distribution of the pad-mount transformers. Most known pad-mounted transformers are between 11-10 years old. Figure 3-11 provides the age demographics for pad-mounted transformers by TUL. The TUL for pad-mount transformers is 40 years. Pad-mount transformers within 13 years of TUL were classified as Approaching TUL. The results show that 5 pad-mounted transformers are of unknown age. Among the known set of pad-mount transformers 1,117 are not near TUL, 699 are approaching TUL, and 51 are past TUL.

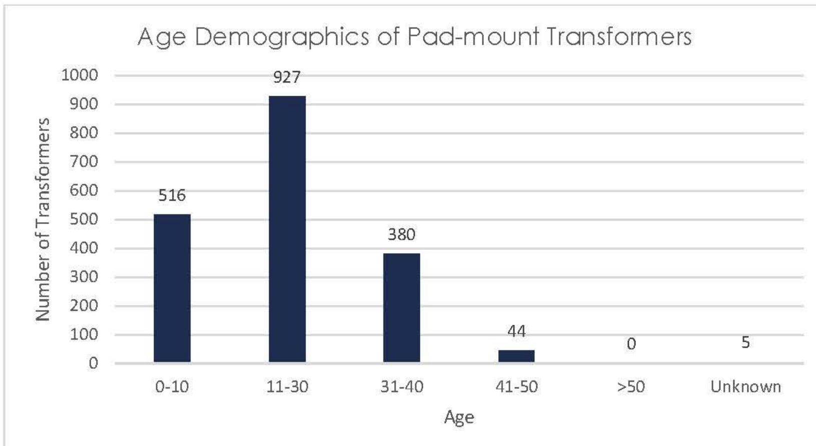


Figure 3-10: Consolidated Age Demographics of Pad-mount Transformers

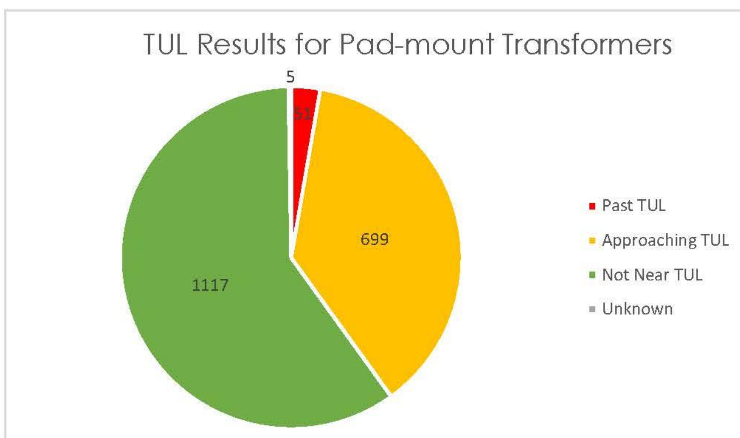


Figure 3-11: Age Summary Pad-Mount Transformer by TUL

EPLC owns 983 pole-mount distribution transformers across its four service areas. The service age is known for 98% of the pole-mount transformers. Table 3-12 presents the age demographics of pole-mounted transformers by community. The majority of pole-mounted transformers are in LaSalle. Figure 3-12 presents the age distribution of pole-mounted transformers. Most known pole-mounted transformers are between 11-30 years old.

Figure 3-13 provides the age demographics for pole-mount transformers by TUL. The results show that 22 pole-mounted transformers are of unknown age. Among the known set of pole-mounted transformers, 449 are not near TUL, 334 are approaching TUL, and 178 are past TUL.

Table 3-12: Pole-Mounted Transformer Age Demographics by Service Area

Age	Number of Pole-Mounted Transformers				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	29	41	25	130	225
11-30 years	23	109	32	169	333
31-40 years	32	57	31	137	257
41-50 years	18	43	4	72	137
>50 years	0	8	0	1	9
Unknown	2	2	16	2	22
Total	**104**	**260**	**108**	**511**	**983**

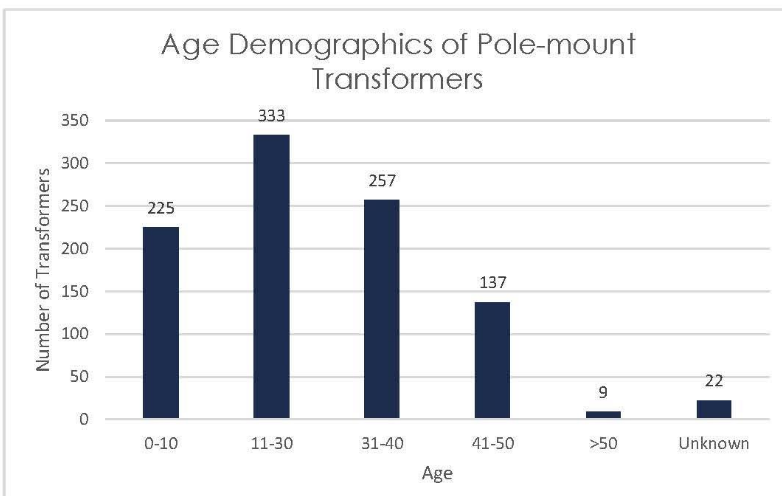


Figure 3-12: Consolidated Age Demographics of Pole-mount Transformers

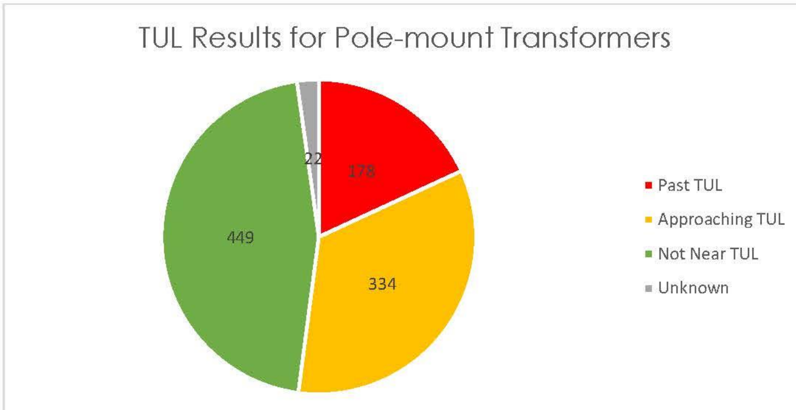


Figure 3-13: Pole-Mount Transformer Age Summary by TUL

HI Results

EPLC owns 1,872 pad-mounted transformers and 983 pole-mounted transformers. Valid HI results were calculated for 1,918 pad-mounted transformers and 1,136 pole-mounted transformers. If service age was not listed the HI was calculated based on visual inspection results and IR results. The HI results for pad-mount and pole-mount transformers are summarized in Table 3-13, Table 3-14, Figure 3-14, and Figure 3-15. Most of EPLC's distribution transformers are in very good or good condition.

Table 3-13: Pad-Mount Transformers HI Results by Service Area

Condition	Number of Pad-Mounted Transformers by Service Area					
	Tecumseh	Leamington	Amherstburg	LaSalle	Unknown Area	Total
Very Good	287	302	231	578	0	1398
Good	137	73	71	128	0	490
Fair	18	26	11	9	0	64
Poor	0	0	0	0	0	0
Very poor	0	0	0	0	0	0
Unknown HI	0	0	0	0	0	1
Total	**443**	**401**	**313**	**715**	**0**	**1872**

Table 3-14: Pole-Mount Transformers HI Results by Service Area

Condition	Number of Pole-Mounted Transformers by Service Area					
	Tecumseh	Leamington	Amherstburg	LaSalle	Unknown Area	Total
Very Good	52	148	73	294	0	567
Good	33	59	30	141	0	263
Fair	19	53	5	76	0	153
Poor	0	0	0	0	0	0
Very poor	0	0	0	0	0	0
Unknown HI	0	0	0	0	0	0
Total	**104**	**260**	**108**	**511**	**0**	**983**

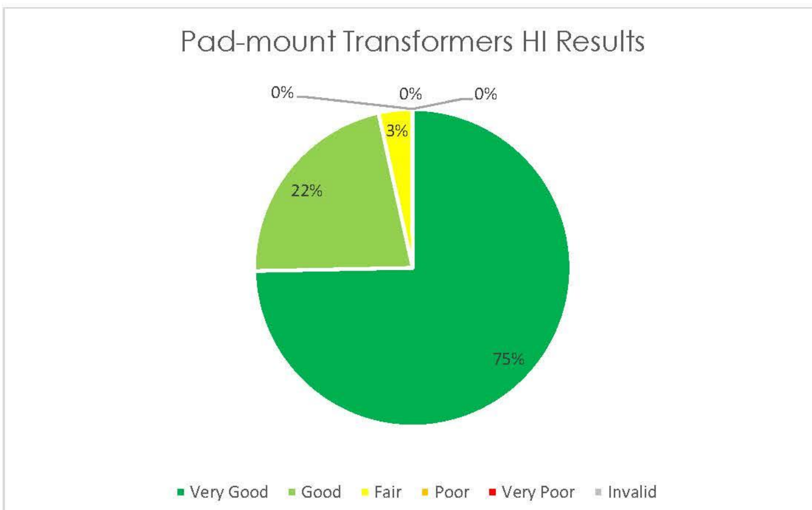


Figure 3-14: Pad-Mounted Transformer HI Results

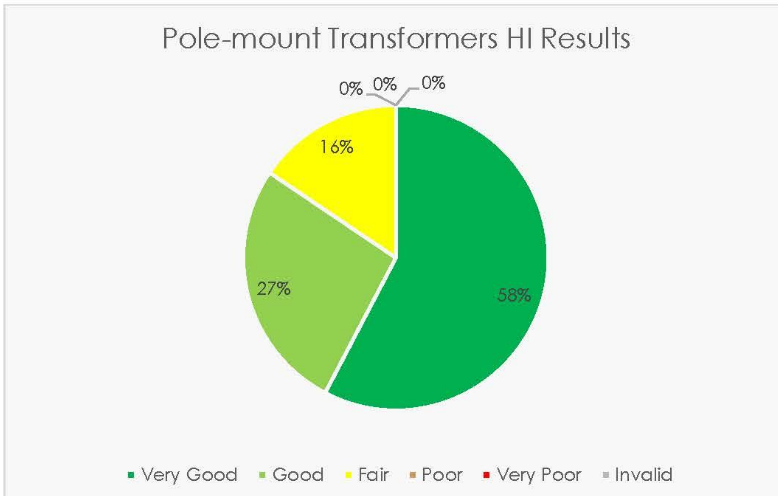


Figure 3-15: Pole-Mounted Transformer HI Results

3.1.5. Load-Break Switches

Condition Assessment Methodology

Switches represent critical infrastructure for electrical utilities. The primary means of inspecting and maintaining switches are to visually identify dirt and corrosion and to use IR scans to find "hot" connections. Traditional air-insulated, handle-operated switches are highly maintainable and can often be extended indefinitely and nearly completely rebuilt on the pole. Newer single-piece devices can also be maintained but would generally be removed from the pole and maintained in a shop setting.

The HI for distribution load-break switches is calculated by considering the overall condition of the asset. Table 3-15 provides the two-parameter HI algorithm for load-break switches. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 3-15: Load-Break Switch HI Algorithm

Condition Criteria	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	2	A,B,C,D,E	4,3,2,1,0	8
IR Scan	2	B,C,D,E	3,2,1,0	6
			Total Score	**14**

Data Collection and Assumptions

Visual inspection results and IR results were used to calculate the HI for EPLC's load-break switches. Visual Inspection results were recorded between 2017-2020. It should be noted that all assets showed no issues from IR inspection. The average DAI for this asset class is 100%.

Demographics

EPLC owns 66 load-break switches. Service Age was unknown for all load-break switches; however, since visual inspections including IR scan results are performed and recorded, age is not necessary for this asset's analysis.

HI Results

Valid HI results were calculated for load-break switches. The HI results for load-break switches are presented in Table 3-16 and Figure 3-16. All of EPLC's load-break switches are in Very Good condition.

Table 3-16: Load-Break Switch HI Results by Service Area

Condition	Number of Load-Break Switches by Service Area					
	Tecumseh	Leamington	Amherstburg	LaSalle	Unknown Area	Total
Very Good	12	21	10	23	0	66
Good	0	0	0	0	0	0
Fair	0	0	0	0	0	0
Poor	0	0	0	0	0	0
Very Poor	0	0	0	0	0	0
Unknown HI	0	0	0	0	0	0
Total	**12**	**21**	**10**	**23**	**0**	**66**

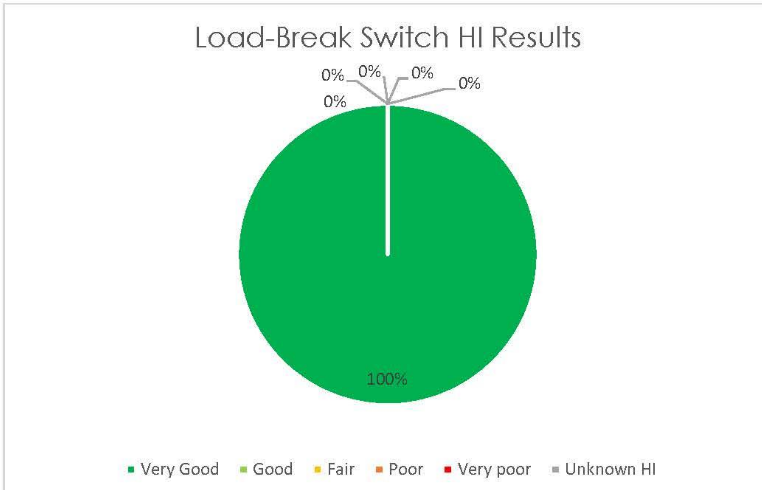


Figure 3-16: Load-Break Switch HI Results

3.1.6. Switchgear and Switching Cubicles

Condition Assessment Methodology

The HI for switchgear units and switching cubicles is calculated by considering a combination of service age and inspection results. Table 3-17 summarizes the methodology to combine these criteria into an overall HI. Additional details about these condition parameters and how they are graded can be found in Appendix A.

Table 3-17: Pad-mount Switchgear & Switching Cubicle HI Algorithm

Condition Criteria	Weight	Ranking	Numerical Grade	Max Score
Visual Inspection	4	A,B,C,D,E	4,3,2,1,0	16
IR Scan	3	A,B,C,D,E	4,3,2,1,0	12
			Total Score	**28**

Data Collection and Assumptions

EPLC currently owns 67 switchgear units and 45 switching cubicles across its four service areas. Service age and visual inspection results are used to calculate the HI for EPLC's switchgear units and switching cubicles. Visual inspection results were recorded between the years 2018 and 2021. Service age was available for 88% of the switchgear units and 36% of switching cubicles.

Visual inspection results were available for 85% of switchgear units and 100% of switching cubicles. The average DAI for switchgear and switching cubicles was 88% and 72%, respectively.

Demographics

EPLC owns 67 switchgear units, and the service age is known for 88% of them. Table 3-18 shows the age demographics for switchgear units by service area. LaSalle and Amherstburg currently have the largest proportion of switchgear units. Figure 3-17 presents the age distribution of switchgear units, which shows that most are between 0-10 years old.

Figure 3-18 shows the age demographics of switchgear units by TUL, which shows that most switchgear units are not near TUL. The TUL for switchgears is 30 years. Switchgears within 10 years of TUL were classified as Approaching TUL.

Table 3-18: Switchgear Age Demographics by Service Area

Age	Number of Switchgear Units				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	5	6	13	18	42
11-30 years	8	0	4	5	17
31-40 years	0	0	0	0	0
41-50 years	0	0	0	0	0
>50 years	0	0	0	0	0
Unknown	0	3	4	1	8
Total	**13**	**9**	**21**	**24**	**67**

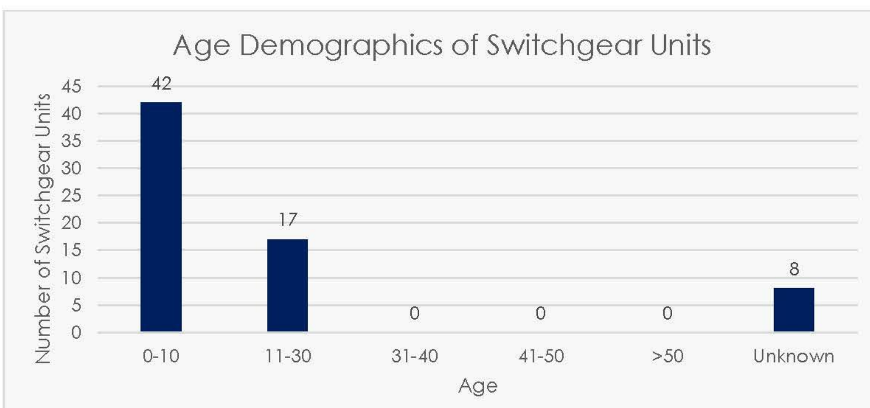


Figure 3-17: Age Demographics of Switchgear Units

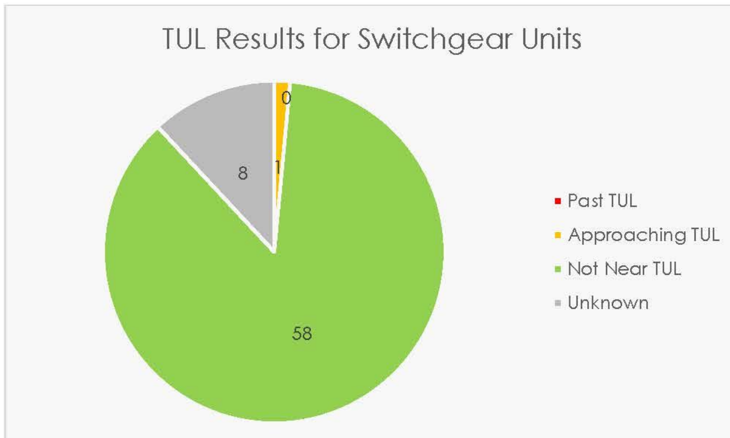


Figure 3-18: Age Summary of Switchgear Units by TUL

EPLC owns 45 switching cubicles, and the service age is known for 36% of them.

Table 3-*19* shows the age demographics for switching cubicles by service area. Currently, Tecumseh and Amherstburg have the largest proportion of switching cubicles. Figure 3-19 presents the age distribution of switching cubicles. The results show that known switching cubicles are between 11-30 years old with the highest proportion being 11-20 years old.

Figure 3-20 shows the age distribution for switching cubicles by TUL. The TUL for switching cubicles is 30 years. Switching cubicles within 10 years of TUL were classified as Approaching TUL. Given that 64% of switching cubicles are of unknown age there exist a lot of uncertainty to the TUL results.

Table 3-19: Age Demographics of Switching Cubicles by Service Area

Age	Number of Switching Cubicles				
	Tecumseh	Leamington	Amherstburg	LaSalle	Total
0-10 years	0	0	0	0	0
11-30 years	7	5	0	4	16
31-40 years	0	0	0	0	0
41-50 years	0	0	0	0	0
>50 years	0	0	0	0	0
Unknown	9	3	16	1	29
Total	**16**	**8**	**16**	**5**	**45**

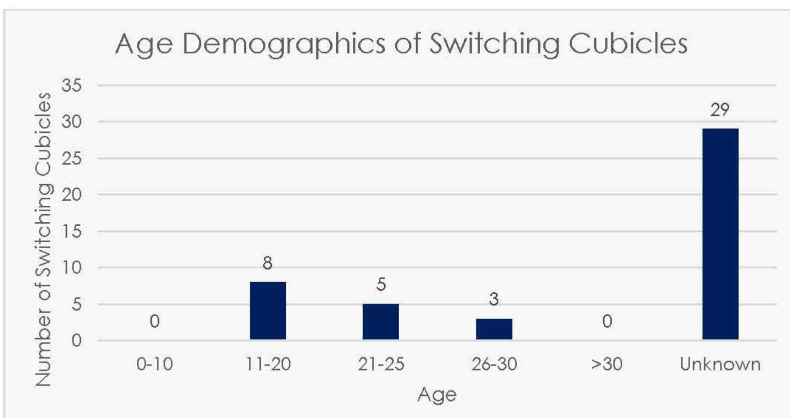


Figure 3-19: Age Demographics of Switching Cubicles

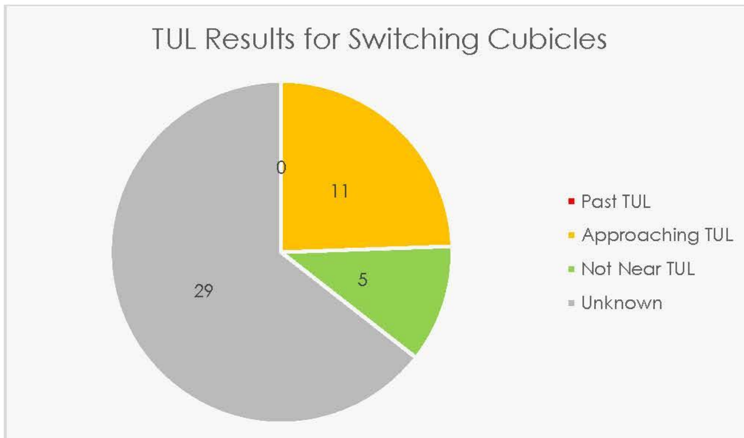


Figure 3-20: Age Summary of Switching Cubicles Age by TUL

HI Results

Valid HI were calculated for 57 pad-mounted switchgear units and all switching cubicles. If the age is unknown, then the HI is calculated solely based on the inspection results. The HI results for both asset classes are presented in *Table 3-20*, *Table 3-21*, *Figure 3-21*, and *Figure 3-22* below. The majority of switchgear units and switching cubicles are in very good condition.

Table 3-20: Switchgear HI Results by Service Area

Condition	Number Switch-Gear Units by Service Area					
	Tecumseh	Leamington	Amherstburg	LaSalle	Unknown Area	Total
Very Good	10	5	21	16	0	52
Good	0	1	0	3	0	4
Fair	1	0	0	0	0	1
Poor	0	0	0	0	0	0
Very poor	0	0	0	0	0	0
Unknown HI	2	3	0	5	0	10
Total	**13**	**9**	**21**	**24**	**0**	**67**

Table 3-21: Switching Cubicle HI Results by Service Area

Condition	Number of Switching Cubicles by Service Area					
	Tecumseh	Leamington	Amherstburg	LaSalle	Unknown Area	Total
Very Good	11	4	15	3	0	33
Good	2	2	0	1	0	5
Fair	3	1	1	1	0	6
Poor	0	0	0	0	0	0
Very poor	0	1	0	0	0	1
Unknown HI	0	0	0	0	0	0
Total	**16**	**8**	**16**	**5**	**0**	**45**

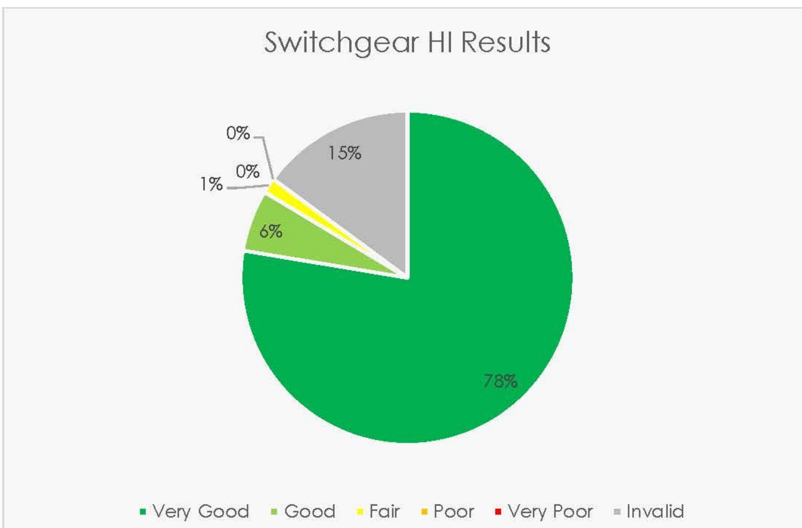


Figure 3-21: Switchgear HI Results

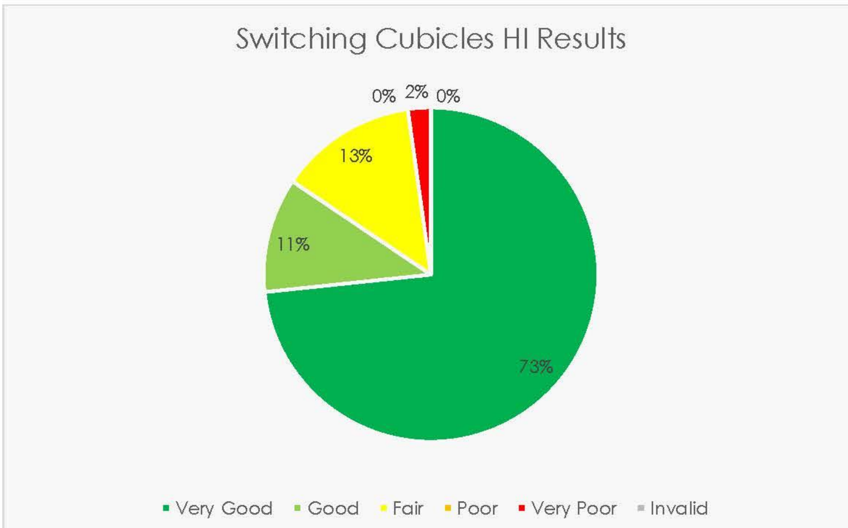


Figure 3-22: Switching Cubicles HI Results

3.2. Primary Conductors and Cables

3.2.1. Overhead Primary Conductors

Condition Assessment Methodology

OH conductor assets tend to be renewed when poles are replaced, when voltages are upgraded, or when lines are restrung for technical reasons. It is very rare that the conductor condition would drive a distinct replacement investment program. There is one recognized conductor risk, namely the tendency for small copper conductors to age at an accelerated rate and become brittle. Although laboratory tests exist to determine the tensile strength and assess the remaining useful life of conductors, distribution line conductors rarely require testing. An appropriate proxy for estimating the tensile strength of conductors and estimating the remaining life of an asset is the use of service age. BBA's recommended HIF for OH conductors is shown in Table 3-22.

Table 3-22: OH Conductor HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	2	A,B,C,D,E	4,3,2,1,0	8
Small Conductor Risk	1	A,E	4,0	4
			Total Score	**12**

Data Collection and Assumptions

The asset information provided by EPLC was used to complete the assessment of OH conductors. A valid HI could not be completed for this asset class due to the poor availability of conductor age information and the lack of small conductor risk data. Age information is only recorded for 9% of the conductor line segments. A TUL of 60 years was used to determine age demographics.

Demographics

EPLC owns 180.4 km of OH primary conductors throughout its four service areas. Figure 3-23 presents the age distribution by service area for EPLC's OH conductors. LaSalle currently has the highest OH conductor length. Figure 3-24 presents the cumulative length of primary OH conductors by installation year. The largest installation of OH conductors by length took place in 2013, where 3.4 km of OH conductors was installed.

Figure 3-25 shows the age demographics by TUL for primary OH conductors. The TUL for OH conductor is 60 years. OH conductor within 20 years of TUL were classified as Approaching TUL. The service age is unknown for 91% of OH conductors. Therefore, there was a lot of uncertainty in the TUL results.

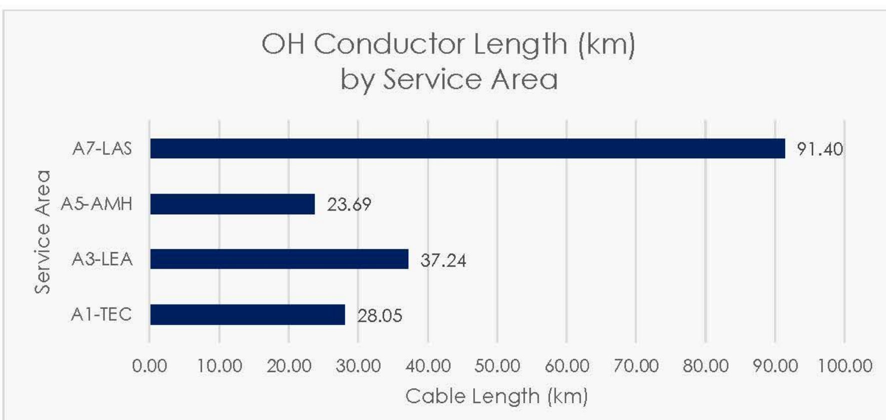


Figure 3-23: OH Conductor Age Demographics by Service Area

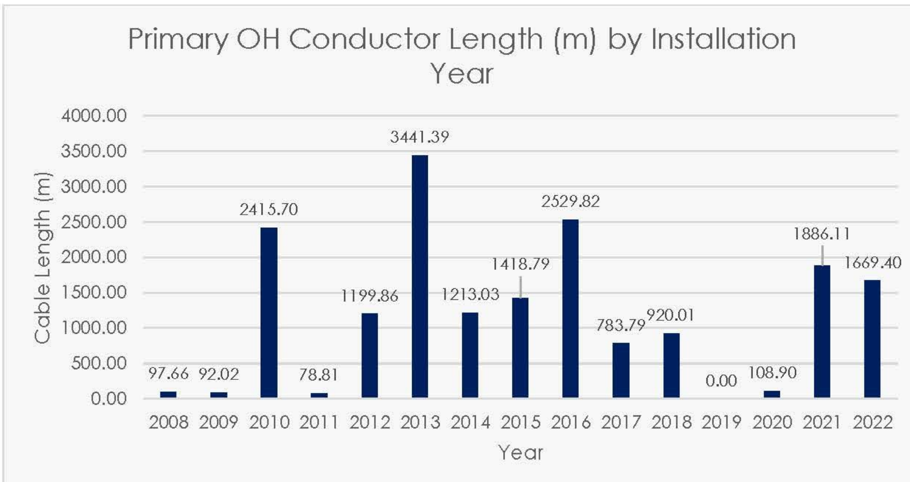


Figure 3-24: Primary OH Conductor Length (m) by Installation Year

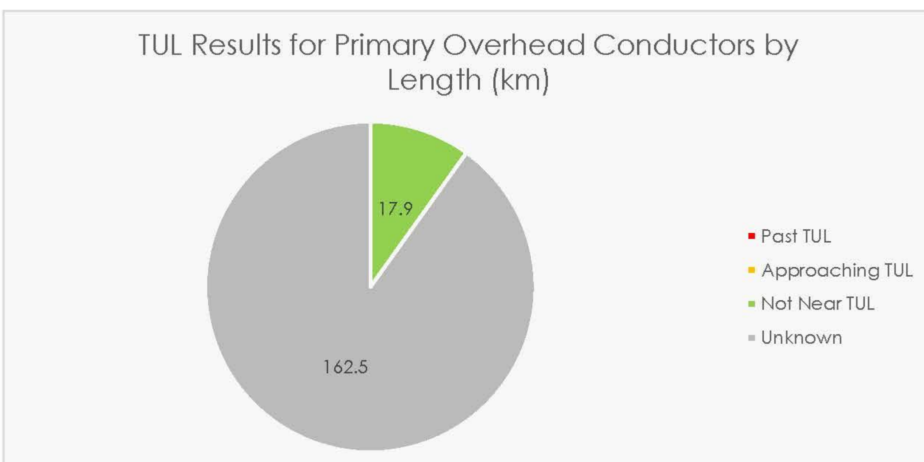


Figure 3-25: Primary OH Conductor Age Summary by TUL

3.2.2. Primary Underground Cables

Condition Assessment Methodology

Distribution UG primary cables are one of the more challenging assets in electricity systems from a condition assessment viewpoint. Although several test techniques, such as partial discharge testing, have become available over recent years, it is still very difficult and expensive to obtain accurate condition information for buried cables. The standard approach to managing cable systems has been monitoring cable failure rates and the impacts of in-service failures on reliability and operating costs. In recognition of these difficulties, cables are replaced when the costs associated with in-service failures, including the cost of repeated emergency repairs and customer outage costs, become higher than the annualized cost of cable replacement.

Service age provides a reasonably good measure of the remaining life of cables with the lack of visual inspection for cable defects. As a minimum, age-based parameters and the knowledge of past failure instances will allow the comparison of a given cable segment to other cables of similar vintage. An additional parameter that can be considered is that any cable sections that have previously experienced a fault are considered a higher risk for recurrence although the data on this topic requires further research.

Many test labs are offering partial discharge ("PD") measurements to assess the condition of cables in service. PD testing of cables is performed online without disrupting the plant or facilities or offline when required. The data obtained from PD tests can provide critical information regarding the quality of cable insulation and its impact on cable system health. Table 3-23 provides the HIF for UG cables. EPLC should consider collecting data for some or all of the HIF condition parameters to support future ACAs for UG cables.

Table 3-23: UG Cable HI Algorithm

Condition Parameter	Weight	Ranking	Numerical Grade	Max Score
Service Age	10	A,B,C,D,E	4,3,2,1,0	40
Cable Failure Analysis	10	A,B,C,D,E	4,3,2,1,0	40
Field Testing	10	A,B,C,D,E	4,3,2,1,0	40
Condition of Concentric Neutral	9	A,B,C,D,E	4,3,2,1,0	36
Outage Records in Last 5 Years	8	A,B,C,D,E	4,3,2,1,0	32
Loading History	5	A,B,C,D,E	4,3,2,1,0	20
			Total Score	**208**

Data Collection and Assumptions

A valid HI could not be completed for this asset class due to the absence of condition or testing records. Instead TUL was estimated based on service age and installation method (Conduit or Direct Buried), which is shown in the table below.

Table 3-24: UG Cable TUL

Asset Class	TUL (years)
Direct-buried Primary UG Cables	30
Primary UG Cables in Conduit	40

Demographics

EPLC owns 279.0 km of primary UG cable throughout its four service areas. The installation year is known for 83% of the total UG cable length. Figure 3-26 presents the distribution of EPLC's UG Cables by service area. LaSalle currently has the largest UG cable length. Figure 3-27 and Figure 3-28 present the cumulative cable length by installation year for both conduit and direct primary UG cables. For cables installed in conduit the largest length of UG primary cables was installed in 1990. For cables directly buried the largest length of UG primary cables was installed in 1994.

Figure 3-29 shows the age demographics of primary UG cables by TUL. The TUL for direct-buried UG cables is 30 years and the TUL for UG cables in conduit is 40 years. UG cables within 10 and 13 years of TUL were classified as Approaching TUL for direct-buried cables and cables in conduit respectively. A total of 158.4 km of UG cables are in very good condition. Furthermore, a total of 34.1 km of UG cables are of unknown age, which adds some uncertainty to the results.

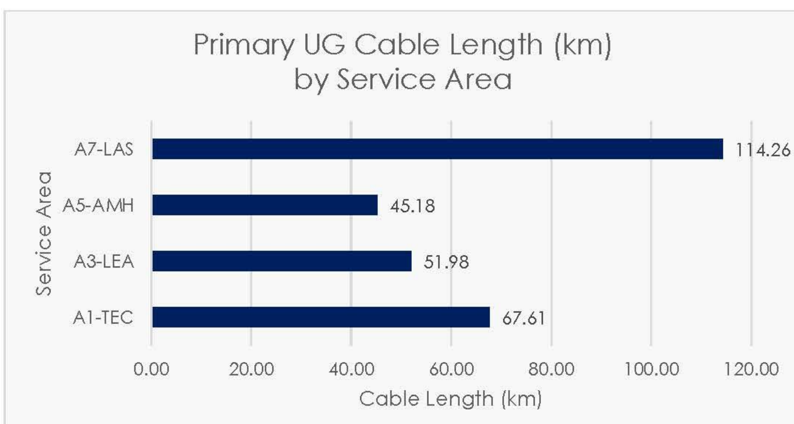


Figure 3-26: UG Cable Age Demographic by Service Area

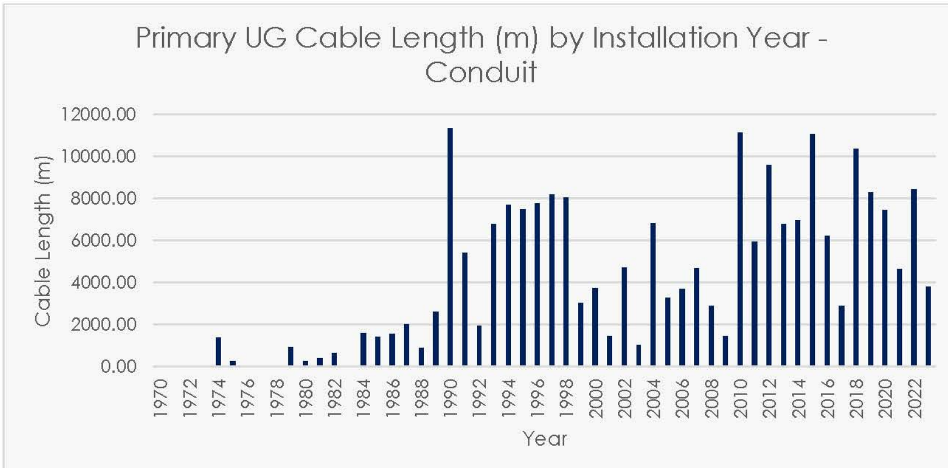


Figure 3-27: Primary UG Cable Length (m) by Installation Year – Conduit

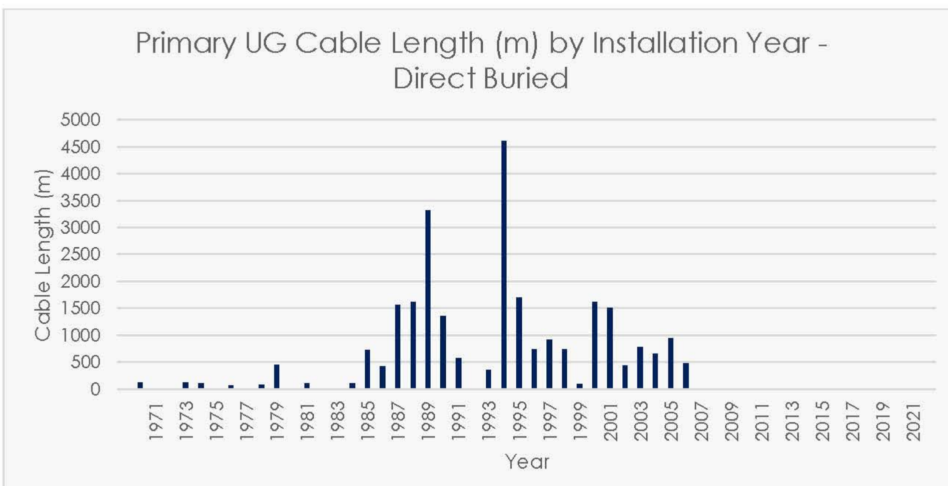


Figure 3-28: Primary UG Cable Length (m) by Installation Year – Direct Buried

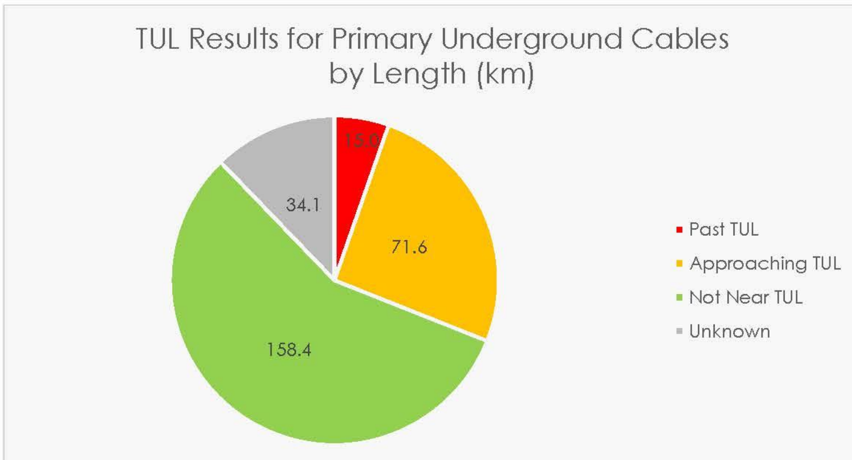


Figure 3-29: Primary UG Cable Age Summary by TUL

4. Conclusions & Recommendations

4.1. Conclusions

On top of a condition assessment of EPLC's major asset classes, this report provided EPLC with a broad range of recommendations with respect to specific types of information that it may choose to collect to enhance it's AM analytics. HI and age demographics presented in this document will help EPLC understand both the current condition of their assets and how it will change into the future. The results of this ACA give EPLC the resources they need to plan for short and long-term care of their assets.

Keeping records of assets' condition is good practice, as it may assist in planning and assessing the quality of assets to be replaced. BBA recommends collecting and keeping condition records consistent for all assets inspected. Obtaining and organizing more comprehensive inspection data records would establish a stronger baseline of the asset health indices rather than being dependent on age. BBA suggested additional variables for EPLC to keep track of. For example, keeping track of cable failure analysis records, field testing records, and outage records for UG cables would allow BBA to calculate a proper HI. BBA recommends that EPLC incorporate a five-level grading scheme for any asset condition inspections, where applicable to bring its practices closer to the ISO55000 recommended approaches. A five-level grading scheme will allow for more discrepancy between assets and their respective HI values that will be used for prioritizing assets.

4.2. Recommendations for Asset Investment Planning

A proactive asset investment strategy should focus on replacement of Very Poor and Poor-condition assets over the short term. These replacements can be prioritized based on asset risk. Table 2-1 notes that assets in Fair condition may also require replacement or remedial work depending on their criticality (and its effect on risk). Long-term planning should consider the asset demographics and plan to address assets at or reaching their TUL over the next ten years. This is a sustainable investment approach because it avoids harvesting the assets and mitigates current and future risk on the system.

4.3. Recommendations for Data Improvement

BBA recommends that EPLC should focus their efforts on collecting missing asset data noted in this study and collecting data for new condition parameters to improve the accuracy and add incremental value from a more granular approach. The advanced parameters typically represent the measurements associated with equipment degradation processes known to be most detrimental to the normal operation of electrical assets over time.
BBA recommends that EPLC should focus their efforts on collecting missing asset data noted in this study and collecting data for new condition parameters to improve the accuracy and add incremental value from a more granular approach. The advanced parameters typically represent the measurements associated with equipment degradation processes known to be most detrimental to the normal operation of electrical assets over time.

The following set of recommendations consolidates BBA's suggestions provided throughout Section 3**Error! Reference source not found.**. The recommendations target additional condition parameters or the means of collecting and storing the data already being utilized. The recommendations are based on the advanced ACA framework for assets and should not be interpreted as suggesting that immediate action is warranted.

4.3.1. Wood Poles

EPLC's inspection records generally provided useful condition information for wood poles. EPLC should ensure that remaining strength, overall condition, surface decay and mechanical damage are all recorded when pole inspections are completed. EPLC should consider consolidating its inspection records and asset registry. Inspection comments were recorded in two columns that contained similar information. One suggestion would be to combine inspection comments into a single column. Another option would be to store the most recent visual inspection results for wood poles (e.g., presence of cracks, woodpecker, or insect damage) in the asset registry file. These suggestions would allow asset information and inspection records to be combined and correlated easily for future condition assessments. The condition data currently being collected for wood poles is detailed and should be comprehensively recorded for all assets.

4.3.2. Concrete Poles

EPLC's asset and inspection records for concrete poles are stored in the same files as wood poles. Therefore, BBA has similar suggestions for both wood and concrete poles. It should be noted that concrete poles comprise a very small amount of the pole population so creating separate files for concrete poles is not immediately necessary. Recognized HI guides recommend more than a two-parameter formulation to develop a robust index for concrete poles. A best-practice formulation would consider various condition parameters recorded during a visual inspection in addition to service age. This would include:

- Evidence of rust/corrosion;
- Evidence of concrete spalling; and
- Evidence of other mechanical damage or defects.

4.3.3. Dip Poles (Primary Risers)

EPLC's asset and inspection records for Dip Poles are stored separately from wood and concrete poles. Overall, the inspection results for Dip Poles were clear and well organized. Suggestions include keep asset information consistent across all asset classes.

4.3.4. Distribution Transformers

It is recommended that EPLC establish transformer demographics for all distribution transformers as part of a regular inspection. The inspection data currently being collected for distribution transformers is detailed and should be comprehensively recorded for all assets.

4.3.5. Load-Break Switches

Unlike for distribution transformers BBA did not receive an IR report for Load-Break switches. EPLC mentioned that the absence of the report indicated that no issues were found in the IR inspection. BBA recommends EPLC to standardize their IR reports across all asset classes. It is recommended that ELPC conduct inspection testing on load-break switches, as the most recent inspection data is from 2020. EPLC should consider standardizing the load-break switch inspection comments to streamline the process of condition assessment. Ideally, all condition assessments should implement a five-level grading scheme. Condition data should be collected for any additional assets that are in service but do not exist in the inspection file.

Recognized HI guides recommend a multi-parameter formulation that can include service age, condition of blades, and operating mechanism condition, in addition to what EPLC is currently collecting.

4.3.6. Switchgear & Switching Cubicles

EPLC will need to improve the age availability of switching cubicles. Service Age was only available for 36% of switching cubicles. This would allow EPLC to have a better understanding of the age demographic of their assets.

4.3.7. Overhead Conductors

EPLC will need to improve the age availability of OH conductors. Service Age was only available for 9% of primary OH conductors. It is recommended that EPLC record the Facility ID of the closest pole to each conductor line segment. Once this is done, the age of each line segment can be estimated based on the age of the closest distribution pole.

EPLC should also ensure that all OH conductor segments of #4 or #6 copper are tagged in the asset registry. These small copper conductors tend to age at an accelerated rate and become brittle. This condition parameter is important to include in the OH conductor Health Index Formulation ("HIF").

4.3.8. Underground Cables

Asset information for Primary UG Cables was clear and organized. Service age was available for 88% of UG cables. Cable failures are tracked but these are not linked to a specific cable ID or circuit.

Recognized HI guides recommend a multi-parameter HIF for UG cables. It is recommended that EPLC perform cable failure analysis, conduct cable testing, and track cable outages by cable/circuit ID to support future ACAs for UG cables.

Appendix A: Condition Parameters Grading Tables

A.1 Wood Poles

Table A-1: Criteria for Wood Pole Inspection Results

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

Table A-2: Criteria for Wood Pole Service Age

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	51 years or older

Table A-3: Criteria for Wood Pole Cavity Test

Condition Rating	Corresponding Condition
A	Cavity < 10% for both tests
B	Cavity ≥ 10% for either test
C	Cavity ≥ 20% for either test
D	Cavity ≥ 30% for either test
E	Cavity ≥ 50% for one test and ≥ 40% for second test

Table A-4: Criteria for Wood Pole Decay Test

Condition Rating	Corresponding Condition
A	Decay < 10% for both tests
B	Minor decay ≥ 10% for one test
C	Significant decay ≥ 20% for one test
D	Major decay ≥ 30% for one test
E	Severe decay ≥ 40% for one test

A.2 Concrete Poles

Table A-5: Concrete Pole Outstanding Issue Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

Table A-6: Criteria for Concrete Pole Service Age

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	51 years or older

A.3 Dip Poles (Primary Risers)

Table A-7: Dip Poles Outstanding Issue Condition Grading

Asset Condition	Inspection Results
Good	No outstanding issues
Fair	One/two low priority issue(s) outstanding
Poor	More than two low priority issues or one/two medium priority issue(s) outstanding
Very Poor	One or more high priority issues or more than two medium priority issues outstanding

Table A-8: Criteria for Dip Pole Service Age

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years
E	51years or older

A.4 Distribution Transformers

Table A-9: Distribution Transformer Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

Table A-10: Criteria for Transformer Service Age

Condition Rating	Age
A	0 to 10 years
B	11 to 30 years
C	31 to 40 years
D	41 to 50 years

E	51 years or older

Table A-11: Distribution Transformer IR Results Grading

Condition Rating	Corresponding Condition
B	No issues were noted
C	Low Temp between 0℃-20℃ at second inspection
D	Med Temp between 20℃-40℃ at second inspection
E	High Temp above 40℃ at second inspection

A.5 Load-Break Switch

Table A-12: Load-Break Switch Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding
C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

Table A-13: Load-Break Switch IR Results Grading

Condition Rating	Corresponding Condition
B	No issues were noted
C	Low Temp between 0℃-20℃ at second inspection
D	Med Temp between 20℃-40℃ at second inspection
E	High Temp above 40℃ at second inspection

A.6 Switchgear & Switching Cubicles

Table A-14: Switchgear & Switching Cubicles Outstanding Issues Condition Grading

Condition Rating	Corresponding Condition
A	No outstanding issues
B	One low priority issue outstanding

C	Multiple low priority issues or one medium priority issue outstanding
D	Multiple medium priority issues outstanding
E	One or more high priority issues outstanding

Table A-15: Criteria for Switchgear & Switching Cubicles Service Age

Condition Rating	Age
A	0 to 10 years
B	11 to 20 years
C	21 to 25 years
D	26 to 30 years
E	31 years or older

APPENDIX C: CUSTOMER ENGAGEMENT SURVEY REPORT

Essex Powerlines

2023 Rate Application Survey

Residential and Small Business Results

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.

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.

INNOVATIVE RESEARCH GROUP

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.

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Demographics

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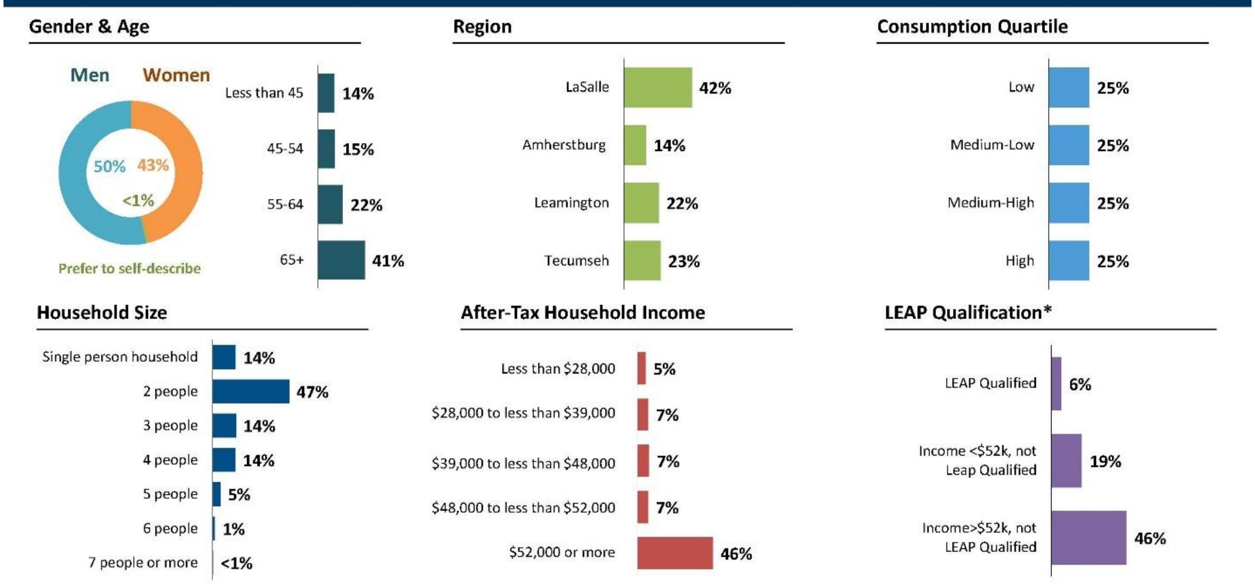
Demographics: Respondent Profile

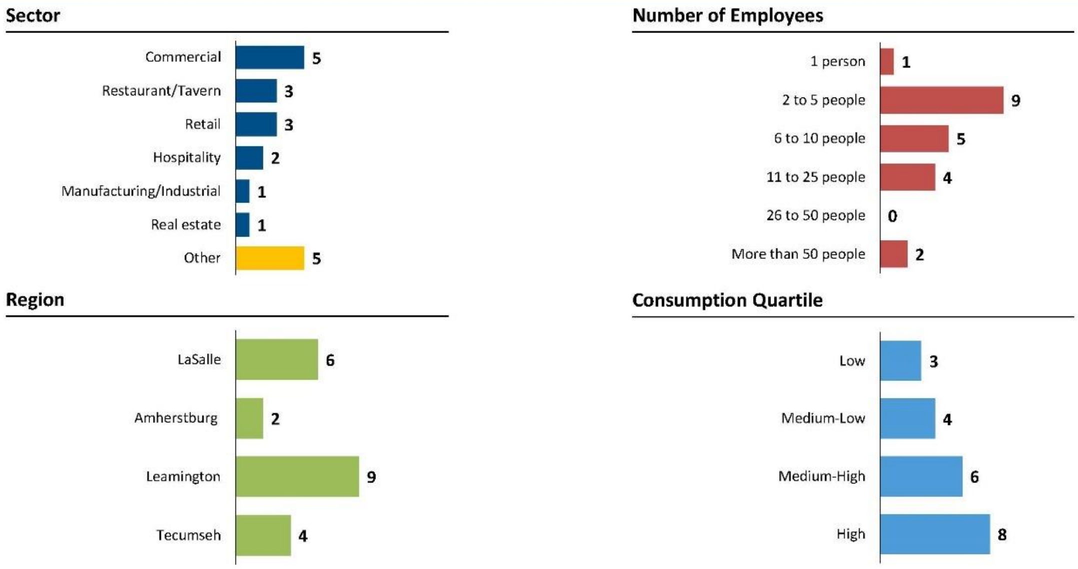
Residential



Note: 'Don't know' and 'Prefer not to say' not shown. *Calculated based on household size and household income

Firmographics: Respondent Profile

Small Business



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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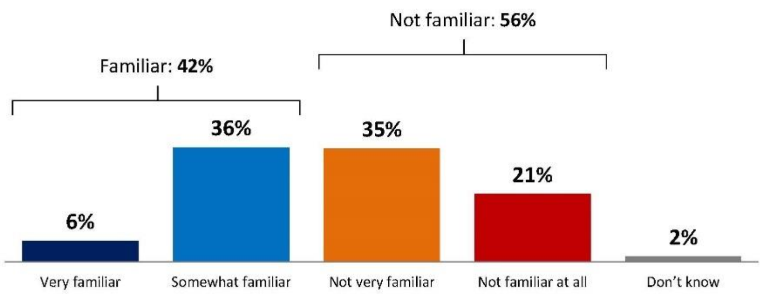
Familiarity with Local Distribution System

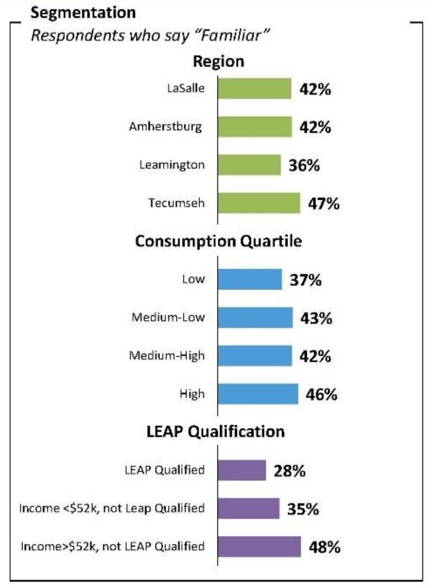
2-in-5 (42%) are very or somewhat familiar with the local electricity distribution system

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.



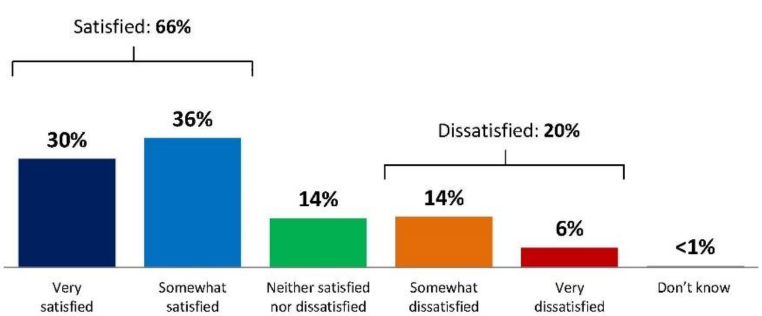


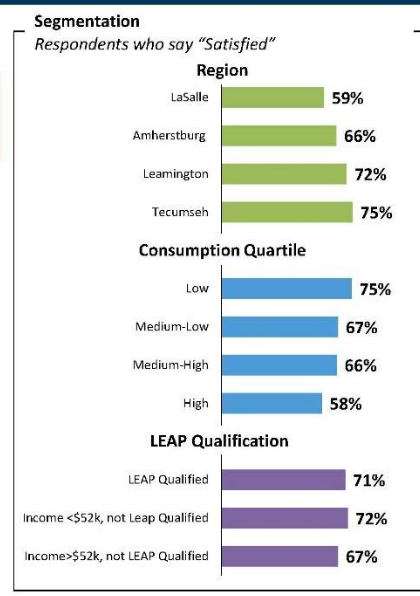
Satisfaction with Service

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.



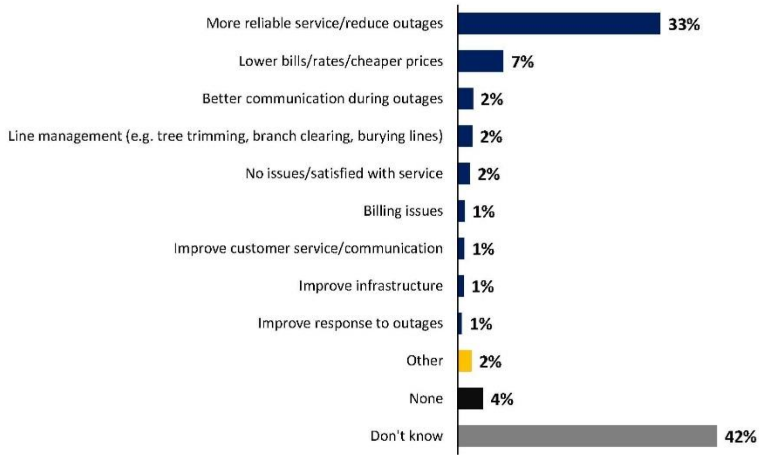


Service Improvement

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



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

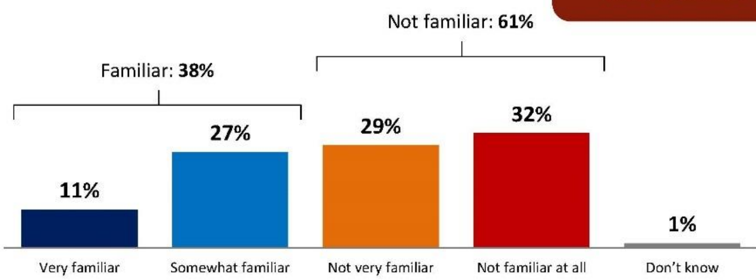
Q

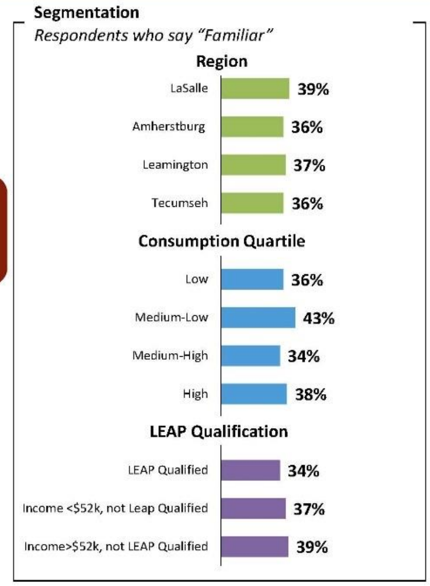
The average [residential/small business] customer pays a fixed monthly service charge of [$29.68/$39.99] which goes to Essex Powerlines. This accounts for approximately 17.8% of a typical [residential/small business] customer's total bill. The rest of the bill goes to power generation companies, transmission 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.





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**.

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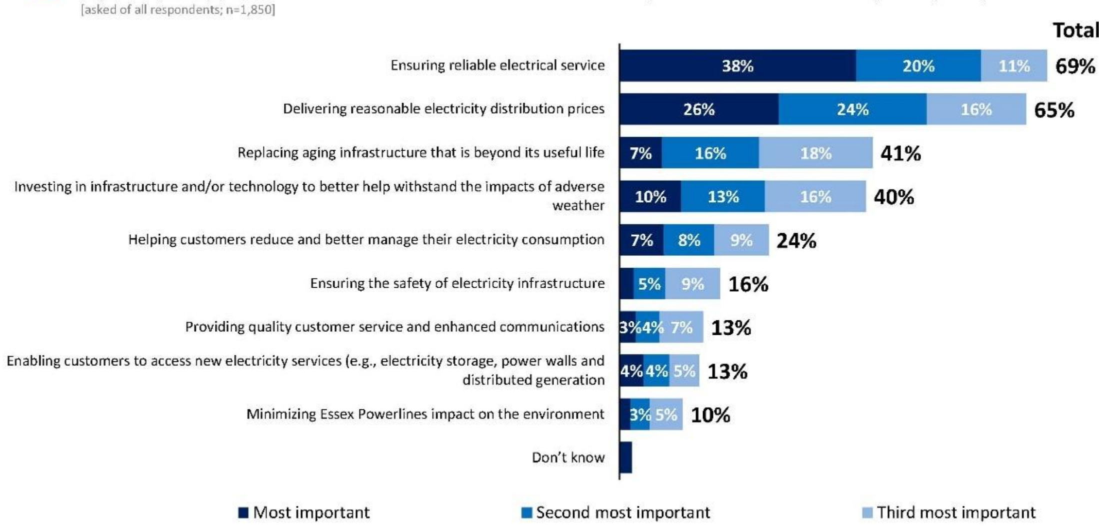
Ranking Priorities

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

19

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]

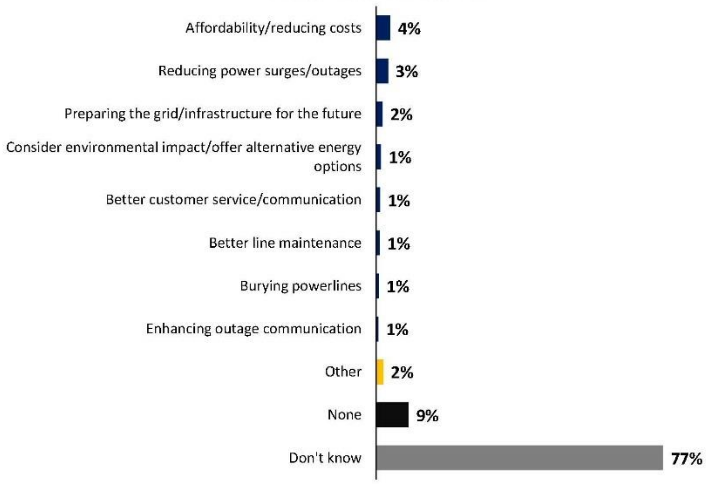
% Select as top three priority	Region				Consumption Quartiles				LEAP Qualification		
	LaSalle	Amherst-burg	Leaming-ton	Tecumseh	Low	Medium-Low	Medium-High	High	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified
Ensuring reliable electrical service	75%	68%	62%	63%	65%	69%	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."

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.

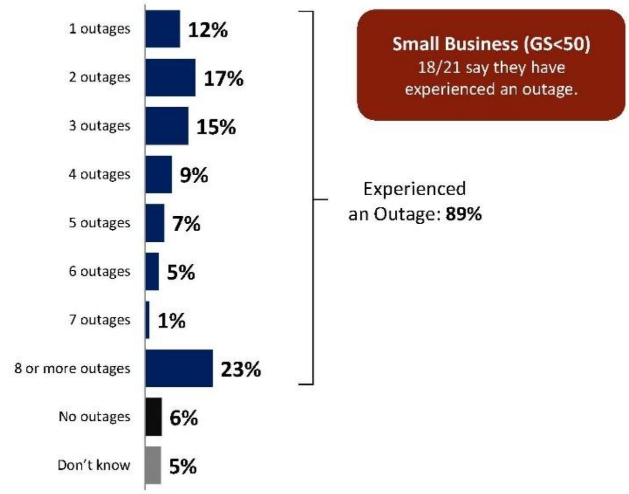
With that said, the average **Essex Powerlines** customer experiences <u>one</u> unplanned power outage per year.

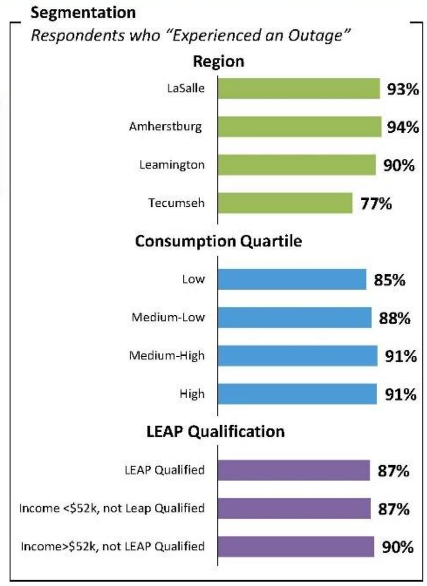
Outage Experiences

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]



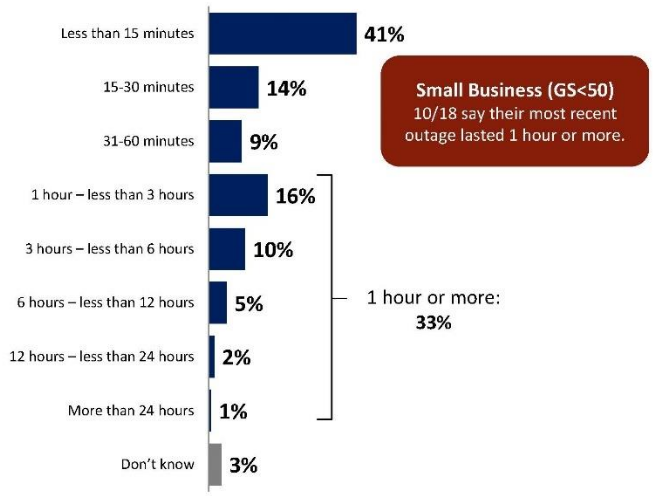


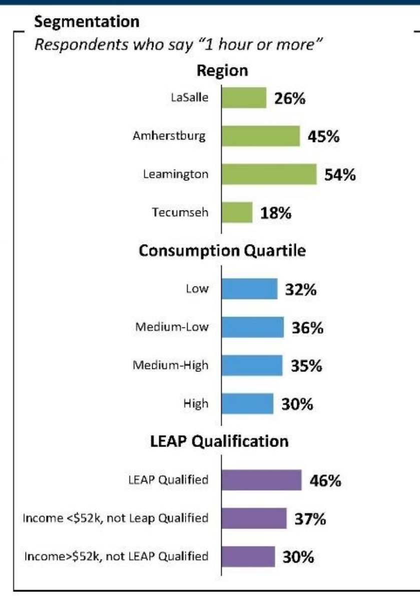
Length of Recent Power Outage

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]

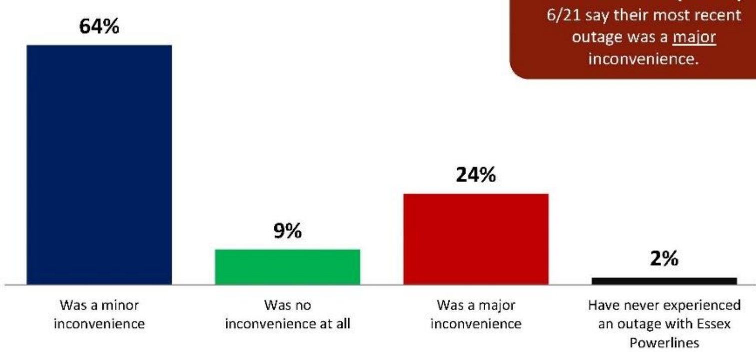




Inconvenience of Outage

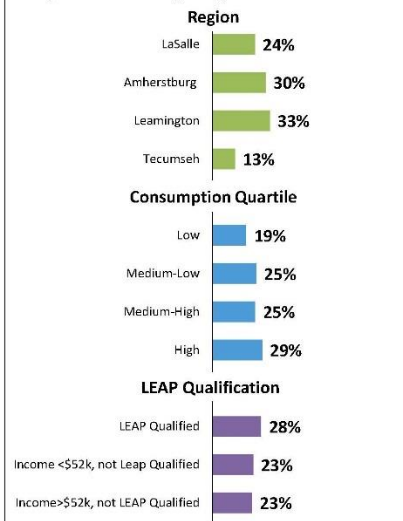
2-in-3 say their latest outage was a minor inconvenience while 1-in-4 say it was a major inconvenience

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"

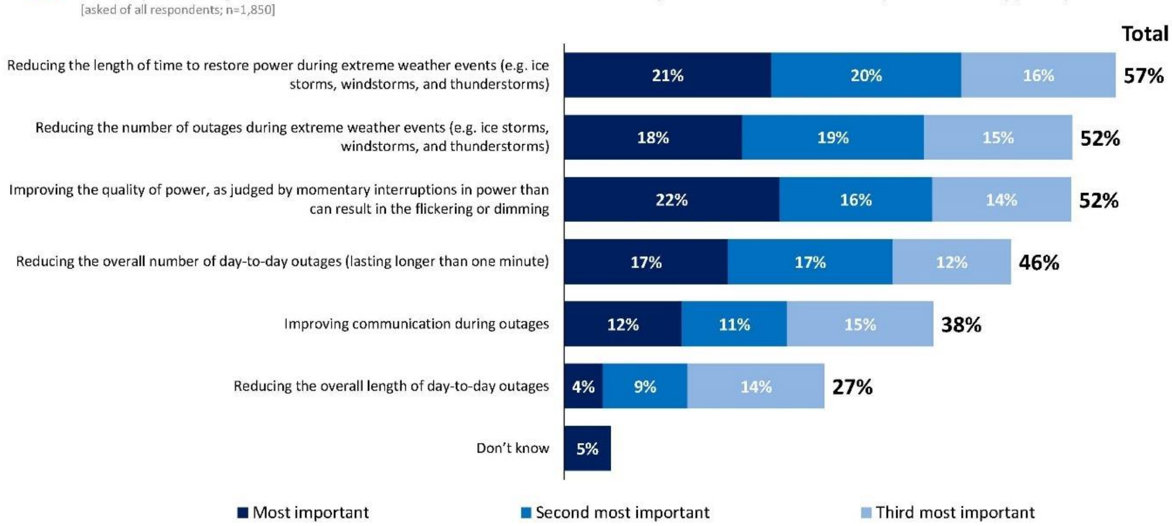


Ranking Reliability Priorities

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%

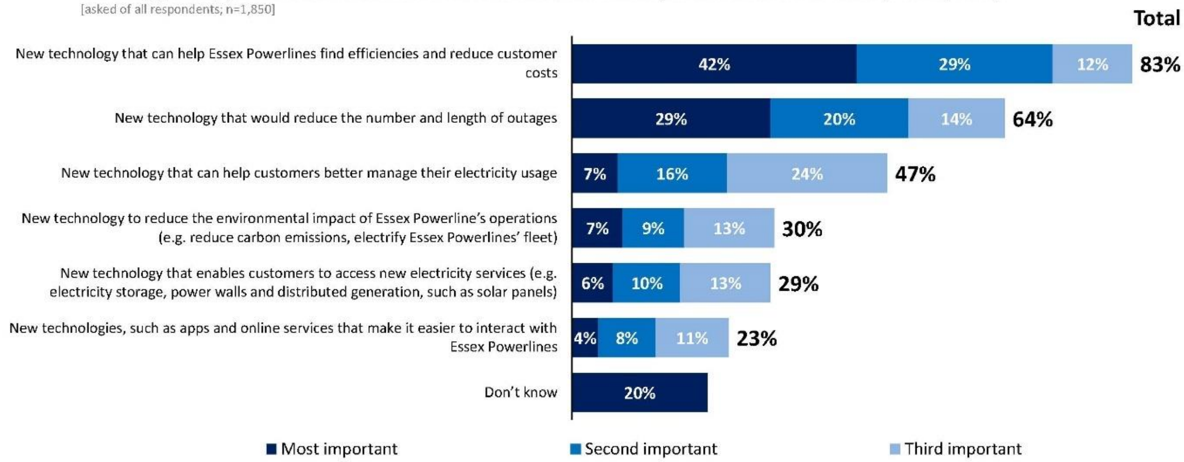
Ranking New Technology Priorities

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 <u>**most**</u> 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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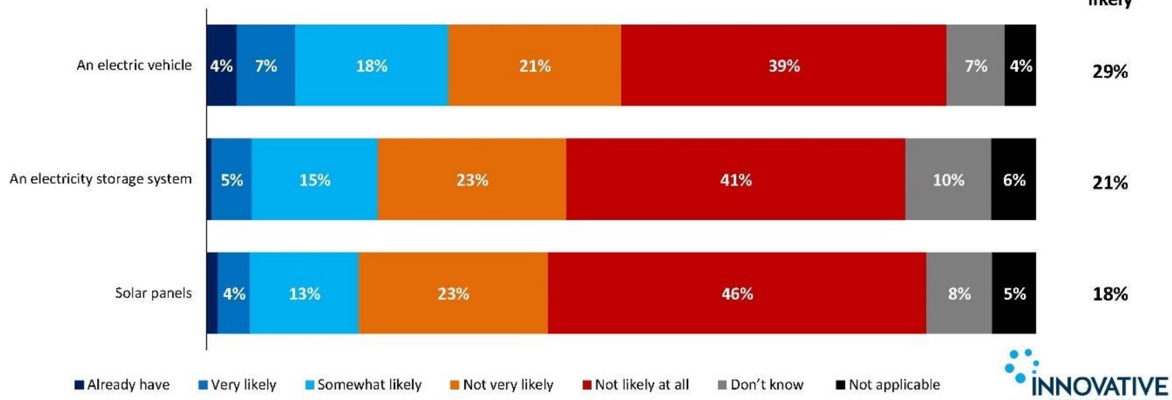
Electrification Investments

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

At least somewhat likely



Electrification 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]

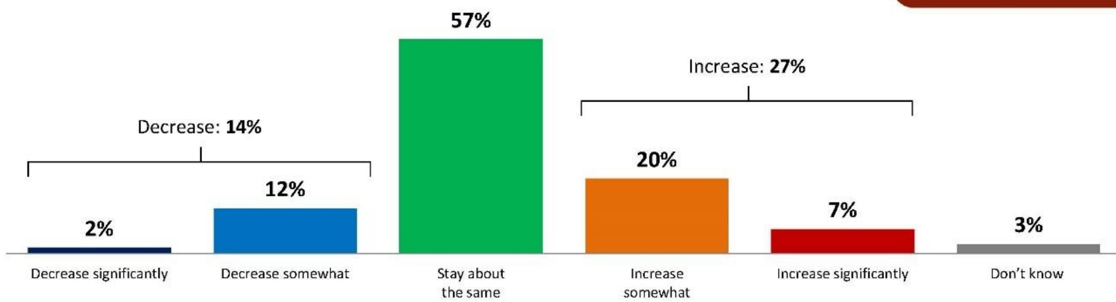
At least somewhat likely	Region				Consumption Quartiles				LEAP Qualification		
	LaSalle	Amherstburg	Leamington	Tecumseh	Low	Medium-Low	Medium-High	High	LEAP Qualified	Income <$52k, not Leap Qualified	Income >$52k, not LEAP Qualified
An electric vehicle	32%	21%	23%	34%	25%	28%	28%	36%	14%	19%	39%
An 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%

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%

Customer Experience

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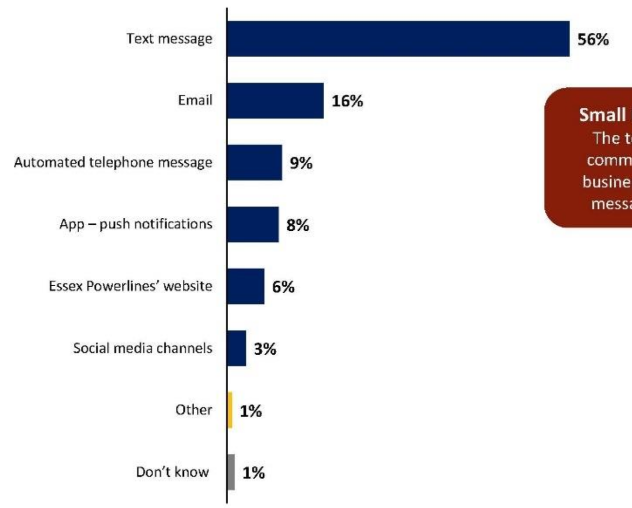
Communicate Outage Information

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).

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Communicate Outage Information by Segments

Across all segments text message is the clear top form of communication for outage information

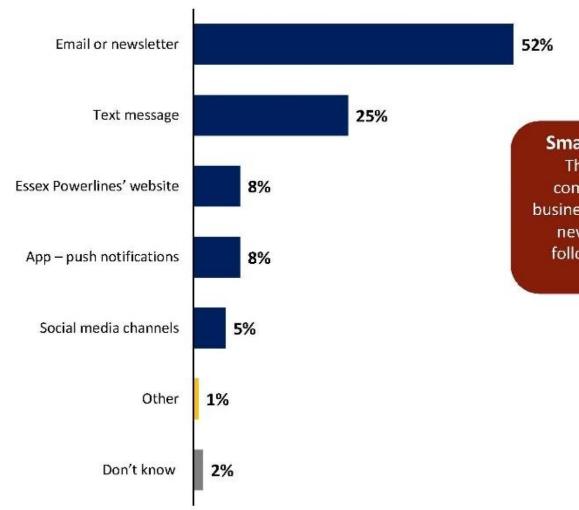
Q There are a number of ways that Essex Powerlines could communicate outage information to customers.
What is the **best way** to communicate outage information to you?
[asked of all respondents; n=1,850]

% 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%

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).

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%	$\boxed{38\%}$	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

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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.*

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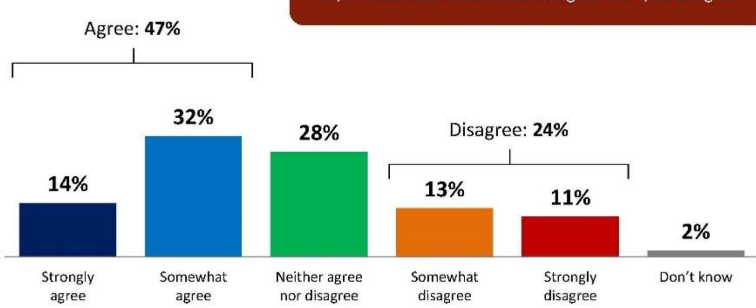
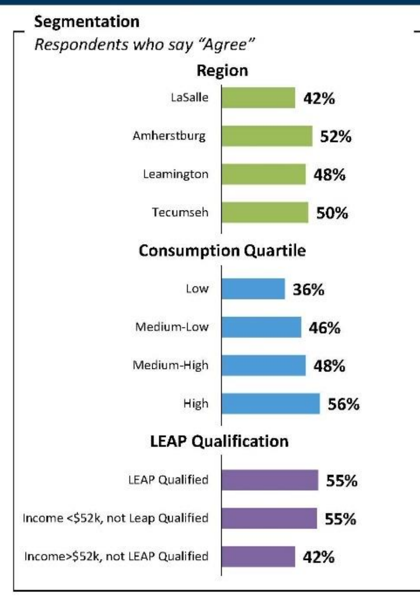
Financial Circumstances

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.



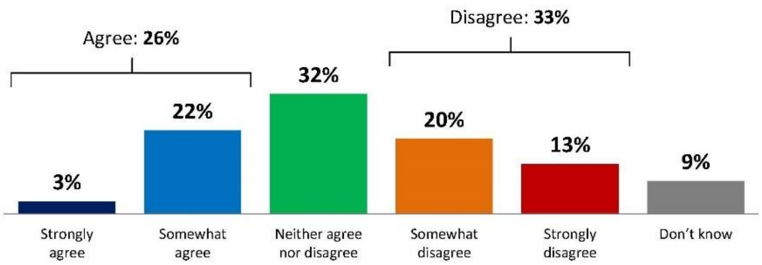


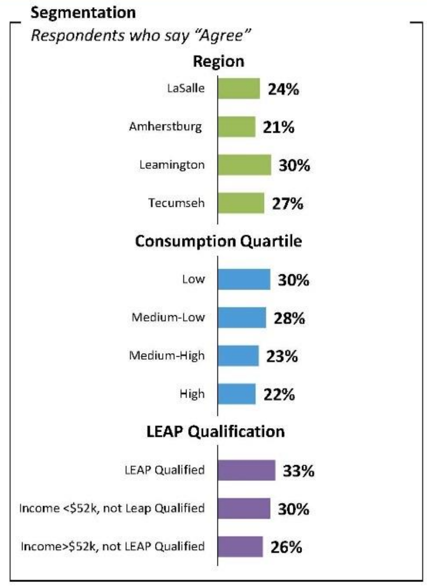
Sector Confidence

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.





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APPENDIX D: EPLC's REG PLAN

ESSEX POWERLINES

Renewable Energy Generation Investments Plan

Prepared for the

Independent Electricity System Operator

To accompany

Essex Powerlines
2024 Cost of Service Application

January 19, 2024

1 Executive Summary

This Renewable Energy Generation (REG) Investments Plan, identifying investment requirements for accommodating Renewable Energy Generation connections, provides information to the Ontario Energy Board and interested stakeholders regarding the readiness of Essex Powerlines Corporation's distribution system to connect renewable energy generation. This includes investment requirements for any expansion or reinforcement necessary to remove grid constraints to accommodate the connections of renewable energy generation over the forecast period of 2025-2029.

There are approximately 35,270 kilowatts (kW) of renewable energy installations connected to Essex Powerlines distribution system, and 0 kW of renewable energy installations connected to Essex Powerlines sub-transmission system under Feed-in-Tariff (FIT), microFIT, RESOP, and Net Metering programs, all of which are solar photovoltaic projects. This includes 15 FIT projects, 186 microFIT, 2 RESOP projects and 13 Net Metering projects. There are currently 5 Net Metering projects with a combined capacity of approximately 585 kW that have applied to Essex Powerlines.

Essex Powerlines has analyzed its circuits for REG connectivity to calculate available capacity for REG connection on each feeder. Based on the findings, Essex Powerlines has no current network investment plans to integrate REG connections.

TABLE OF CONTENTS

INTRODUCTION

Essex Powerlines Corporation is preparing to file a Cost of Service (COS) Application for the prospective rate year of 2025. In accordance with the Ontario Energy Board (OEB) *Filing Requirements for Electricity Transmission and Distribution Applications*, Essex Powerlines has prepared this Renewable Energy Generation (REG) Investments Plan to accompany its Distribution System Plan (DSP) and COS Application.

This REG Investments Plan provides information on Essex Powerlines ability to accommodate new REG connections to its distribution system. The purpose of this REG Investments Plan is to inform the Independent Electricity System Operator (IESO) of any REG investments over the DSP period (2025-2029) and to request the IESO to provide a letter commenting on this information.

Section 3 of this REG Investments Plan provides background information regarding Essex Powerlines distribution system. Section 4 lists the existing and proposed REG connections. Section 5 contains the system assessment to identify constraints. Finally, Section 6 summarizes the proposed investments to facilitate new REG connections.

ESSEX POWERLINES DISTRIBUTION GRID

Essex Powerlines Corporation owns, operates, and maintains a distribution system currently serving approximately 34,0286 customers. Essex Powerlines service area consists of four non-contiguous regions in Essex County located in south-western Ontario: the Town of Amherstburg, the Town of LaSalle, the Municipality of Leamington, and the Town of Tecumseh.

Essex Powerlines industrial customer base is minimal in comparison to residential customers. We have had a steady growth within our service territory in the past 10 years but expect this growth to continue in the next decade. We predict our customer base to grow by approximately 1-2% annually over the next 10 years. Our Business Plan and industry projections support this growth projection.

We currently operate our three-phase distribution system at 27,600 volts. We are completely embedded by Hydro One substations. We currently own, operate, and maintain distribution feeders directly connected into 4 of HONI's substations.

THERMAL CAPACITY CONSTRAINTS

The thermal capacity of the distribution system is the ability of its equipment to carry current. Cables and conductors are rated for the load current they carry. As an embedded electrical distribution company, Essex Powerlines feeder thermal capacity constraints are dependent on HONI substations. The thermal capacities for Essex Powerlines distribution feeders were obtained from HONI's Station and Feeder Capacity Calculator and subject to change.

The table below presents the available thermal capacity for DG at each substation transformer in Essex Powerlines distribution system.

Table 1: Available Thermal Capacity for DG

Distribution Feeder	Connected and In-Progress DG (kW)	Available Thermal Capacity (kW)
KEITH M3	101	4,000
KEITH M4	251	10
KEITH M5	949	15,651
MALDEN M7	224	9,100
MALDEN M9	528	18,750
MALDEN M10	398	10
LAUZON 56M25	72	18,456
LAUZON 56M26	894	17,431
LAUZON 56M4	18	18,645
LEAMINGTON 393M24	849	1,153
LEAMINGTON 393M27	979	17,950

EXISTING AND PROPOSED CONNECTIONS

As of this report date, there are a total of 219 renewable energy generation installations presently connected to Essex Powerlines distribution system under the province's Feed-in-Tariff (FIT), micro-FIT, RESOP, and Net Metering program as summarized below and detailed in Table 2, Table 3, and Table 4, respectively. In summary Essex Powerlines has:

- 15 FIT and 2 RESOP installations with generating capacity of 18,504 kW, listed in Table 2. • 186 micro-FIT installations with 1,563 kW installed capacity, as shown in Table 3.
- 13 solar net-metering installations with 202 kW installed capacity, as shown in Table 4.

There are currently 5 applications in the Net Metering that have not yet proceeded to the development stage, as shown in Table 5.

Table 2 – REG Installations under the FIT & RESOP Program

Address	Fuel Source	Rating (kW)	Station-TS	Feeder	Generation Start Date
12021 McNorton Street, Tecumseh	Solar PV	500	LAUZON	56M26	24-Nov-10
2121 Laurier Parkway, LaSalle	Solar PV	250	KEITH	23M5	9-Dec-11
5890 Malden Road, LaSalle	Solar PV	250	MALDEN	24M9	20-Sept-13
191 Conc 3 North, Amherstburg (RESOP)	Solar PV	10,000	KEITH	23M5	15-AUG-11
191 Conc 3 North, Amherstburg (RESOP)	Solar PV	5,000	KEITH	23M5	15-AUG-11
201 Talbot Street East, Leamington	Solar PV	250	LEAMINGTON	393M24	20-Sept-13
400 Manning Road, Tecumseh	Solar PV	250	LAUZON	56M26	20-Sept-13
83 Sandwich Street South, Amherstburg	Solar PV	250	KEITH	23M5	27-Jun-14
777 Highway 18, LaSalle	Solar PV	200	KEITH	23M5	11-May-15
50 Peter Street, Leamington	Solar PV	150	LEAMINGTON	393M24	10-Aug-15
4 Maxon Avenue, Leamington	Solar PV	226	LEAMINGTON	393M24	11-Oct-16
1950 Kelly Road, LaSalle	Solar PV	112	KEITH	23M5	13-Oct-16

259 Sherk Street, Leamington	Solar PV	146	LEAMINGTON	393M27	18-Oct-16
9201 Howard Avenue, LaSalle	Solar PV	250	MALDEN	24M12	2-Dec-16
24 Oak Street East, Leamington	Solar PV	190	LEAMINGTON	393M27	17-Apr-17
55 Talbot Street West, Leamington	Solar PV	390	LEAMINGTON	393M27	17-Apr-17
129 Erie Street South, Leamington	Solar PV	90	LEAMINGTON	393M27	17-Apr-17
Total		**18,504**			

Table 3 – REG Installations under the Micro-FIT Program

Address	Fuel Source	Rating (kW)	Station-TS	Feeder	Year
42B Chyenne Crt	Solar PV	10	LEAMINGTON	393M27	04-May-10
2145 Normandy	Solar PV	8.36	MALDEN	24M9	08-Sep-10
556 Sacred Heart Dr	Solar PV	6	MALDEN	24M9	01-Sep-10
12822 Riverside Dr	Solar PV	4.6	LAUZON	56M26	13-Jul-10
125 Chene St	Solar PV	10	LAUZON	56M26	15-Sep-10
45 Industrial	Solar PV	9.88	LEAMINGTON	393M27	15-Sep-10
7050 Malden Rd	Solar PV	10	KEITH	23M5	29-Oct-10
364 Fairway Cres	Solar PV	5.06	LAUZON	56M25	14-Dec-10
1359 Reaume RD	Solar PV	10	MALDEN	24M9	14-Dec-10
8565 Broderick Rd	Solar PV	10	MALDEN	24M7	26-Jan-11
644 Lacasse Blvd	Solar PV	10	LAUZON	56M26	21-Dec-10
1301 St Anne Blvd	Solar PV	4.37	LAUZON	56M26	10-May-11
377 Erie St S	Solar PV	10	LEAMINGTON	393M27	11-Oct-11

2715 Front Rd	Solar PV	10	KEITH	23M4	26-Apr-11
9449 Malden Rd	Solar PV	10	KEITH	23M4	12-Apr-11
395 Sunnyside Blvd	Solar PV	10	KEITH	23M4	08-Mar-12
375 Tyler Rd	Solar PV	3.8	KEITH	23M4	08-Mar-11
201 Martin Ln	Solar PV	10	KEITH	23M4	18-Aug-11
6630 Matchette Rd	Solar PV	5	MALDEN	24M9	22-Mar-11
6650 Matchette Rd	Solar PV	5	MALDEN	24M9	22-Mar-11
921 Elmgate Cres.	Solar PV	5	MALDEN	24M10	14-Jun-11
590 Laurier Dr	Solar PV	9.88	KEITH	23M4	30-May-11
1905 Delmar St	Solar PV	10	MALDEN	24M9	24-Aug-11
530 Lafferty Ave	Solar PV	10	KEITH	23M4	12-Oct-11
440 Simcoe St	Solar PV	10	MALDEN	24M7	09-Sep-11
1050 Lesperance Rd	Solar PV	10	LAUZON	56M26	24-Nov-11
1336 Reaume	Solar PV	9.89	MALDEN	24M9	18-Oct-11
885 Revland Dr	Solar PV	6.125	LAUZON	56M26	20-Sep-11
1606 Normandy	Solar PV	10	MALDEN	24M9	12-Sep-11
1529 Heatherglen	Solar PV	10	LAUZON	56M26	21-Dec-11
7745 Malden Rd	Solar PV	10	MALDEN	24M9	22-Jun-12
545 Estate Park	Solar PV	6.5	LAUZON	56M25	22-Nov-11
254 Sunnyside	Solar PV	10	KEITH	23M4	26-Oct-17

450 International	Solar PV	5.7	KEITH	23M4	06-Dec-11
12457 Lanoue St.	Solar PV	3.99	MALDEN	24M10	09-Nov-11
146 Meloche Rd	Solar PV	10	MALDEN	24M7	05-Jan-12
8800 Broderick Rd	Solar PV	10	MALDEN	24M10	12-Dec-11
1459 Stuart	Solar PV	7.2	MALDEN	24M9	22-Dec-11
13265 Meadowland	Solar PV	10	LAUZON	56M4	26-Jan-12
8325 Disputed Rd	Solar PV	10	MALDEN	24M7	22-Dec-11
8315 Disputed Rd	Solar PV	10	MALDEN	24M7	04-Jan-12
8550 Disputed	Solar PV	5	MALDEN	24M7	11-Apr-12
96 Alderton St	Solar PV	5.85	LEAMINGTON	393M24	28-Mar-12
655 Sacred Heart	Solar PV	6.45	MALDEN	24M9	01-May-12
20 Cedar Dr.	Solar PV	9.46	LEAMINGTON	393M24	08-Feb-12
12818 Lanoue	Solar PV	7.095	LAUZON	56M26	25-Aug-12
12755 Lanoue	Solar PV	6.45	LAUZON	56M26	19-Sep-12
43 Robinson St	Solar PV	7.31	LEAMINGTON	393M27	23-May-12
6225 Matchette Rd	Solar PV	10	KEITH	23M5	22-Jun-12
192 Erie St North	Solar PV	10	LEAMINGTON	393M24	05-Jun-12
5 Hodgins St	Solar PV	9.88	LEAMINGTON	393M24	16-May-12
460 International St.	Solar PV	7.74	MALDEN	24M9	19-Sep-12
634 Dorset Park	Solar PV	5.16	LAUZON	56M25	18-Sep-12

406 Amberly Cres	Solar PV	10	LAUZON	56M26	26-Oct-12
13589 Riverside Dr.	Solar PV	7.52	LAUZON	56M26	14-Nov-12
2420 Lovell	Solar PV	7.96	MALDEN	24M7	11-Sep-12
38 Riviera	Solar PV	5.8	KEITH	23M3	30-Jul-12
7985 Broderick Rd.	Solar PV	5	MALDEN	24M7	27-Jul-12
415 Tyler Rd.	Solar PV	6.88	KEITH	23M4	12-Jul-12
1244 Shawnee Rd.	Solar PV	7.53	LAUZON	56M26	10-Aug-12
362 Pentilly	Solar PV	8.6	LAUZON	56M25	13-Sep-12
8155 Snake LN	Solar PV	9.6	KEITH	23M4	11-Feb-13
102 Brush Cres.	Solar PV	8.5	KEITH	23M5	01-Oct-12
2675 Bridgeway	Solar PV	9.03	MALDEN	24M9	31-Aug-12
1280 Woodmont	Solar PV	9.89	KEITH	23M3	23-Aug-12
62 Ivan St.	Solar PV	8.94	LEAMINGTON	393M24	06-Nov-12
60 Ivan St.	Solar PV	8.94	LEAMINGTON	393M24	06-Nov-12
96B Princess St.	Solar PV	10	LEAMINGTON	393M24	06-Nov-12
92-94 Princess St.	Solar PV	10	LEAMINGTON	393M24	06-Nov-12
470 Donlon St.	Solar PV	7.2	KEITH	23M4	18-Jan-13
215 Erie St. South	Solar PV	9.89	LEAMINGTON	393M27	05-Nov-12
448 Simcoe St	Solar PV	10	MALDEN	24M7	02-Oct-12
124 Talbot St. West	Solar PV	9.89	LEAMINGTON	393M27	12-Dec-12

William St.	Solar PV	10	KEITH	23M3	22-Nov-12
12493 Riverside Dr. E	Solar PV	4.52	LAUZON	56M26	28-Sep-12
620 Sacred Heart	Solar PV	9.89	MALDEN	24M9	06-Nov-12
7815 Matchette	Solar PV	10	KEITH	23M4	29-Nov-12
1731 Homestead	Solar PV	6.88	MALDEN	24M7	21-Nov-12
30 Coronation Ave	Solar PV	8.6	LEAMINGTON	393M27	21-Nov-12
143 Arlington	Solar PV	9.68	LAUZON	56M25	26-Feb-13
850 Green Valley Dr.	Solar PV	7.74	LAUZON	56M4	07-Dec-12
517 Dresden Pl.	Solar PV	6.88	LAUZON	56M25	30-Nov-12
8920 Canard Dr.	Solar PV	10	KEITH	23M5	14-Feb-13
15 Countess St.	Solar PV	4.9	LEAMINGTON	393M27	20-Feb-13
14 Orange St.	Solar PV	8.6	LEAMINGTON	393M24	27-Feb-13
44 Wigle Ave.	Solar PV	8.6	LEAMINGTON	393M24	13-Feb-13
1650 Seventh Conc.	Solar PV	7.1	MALDEN	24M7	03-Jun-13
2560 Front Rd.	Solar PV	6.45	KEITH	23M4	12-Jun-13
1923 Edgemore	Solar PV	10	MALDEN	24M9	30-Apr-13
2855 Bouffard	Solar PV	7.8	MALDEN	24M7	23-Dec-13
330 Runstedler	Solar PV	8.6	KEITH	23M4	06-Jun-13
2721 Front Rd.	Solar PV	8.6	KEITH	23M4	07-Aug-13
1058 St. Pierre	Solar PV	6.45	LAUZON	56M26	20-Jun-13

7680 Matchette Rd	Solar PV	9.99	KEITH	23M5	11-Sep-13
323 Simcoe St.	Solar PV	10	KEITH	23M3	23-Sep-13
51 Martin Cres.	Solar PV	10	MALDEN	24M7	23-Sep-13
695 Victory	Solar PV	8.6	KEITH	23M4	14-Nov-13
30 Orange St.	Solar PV	8.17	LEAMINGTON	393M24	17-Oct-13
258 McCurdy	Solar PV	7.53	KEITH	23M3	24-Jun-13
12777 Jacie Court	Solar PV	8.6	LAUZON	56M26	10-Jul-13
50 Victoria Ave. N	Solar PV	10	LEAMINGTON	393M24	30-Sep-13
36 Fox St.	Solar PV	5	LEAMINGTON	393M27	09-Oct-13
8780 Malden Rd	Solar PV	6.45	KEITH	23M5	18-Jul-13
4399 St. Clair Ave	Solar PV	6.45	MALDEN	24M7	30-Jan-14
895 Reaume Rd.	Solar PV	6.45	KEITH	23M5	09-Jan-14
380 Sacred Heart	Solar PV	8.6	MALDEN	24M9	21-Jan-14
1455 Champ Cres.	Solar PV	4.94	MALDEN	56M26	17-Oct-13
7 Seacliff Dr. W	Solar PV	10	LEAMINGTON	393M27	25-Sep-13
570 Dunn St.	Solar PV	7.6	MALDEN	24M9	03-Dec-13
918 Elmgate Cres.	Solar PV	7.6	MALDEN	24M7	30-Jan-14
2727 Front Rd	Solar PV	8.6	KEITH	23M4	08-May-14
792 Michael Dr.	Solar PV	7.8	LAUZON	56M26	06-May-14
12219 Valente Crt	Solar PV	10	LAUZON	56M26	11-Jun-14

135 Antaya	Solar PV	8.6	KEITH	23M4	11-Jun-14
26 Chestnut St.	Solar PV	7.6	LEAMINGTON	393M27	12-Dec-14
26 Pearl Ave.	Solar PV	8.6	LEAMINGTON	393M24	10-Oct-14
1715 Minto Ave.	Solar PV	10	MALDEN	24M9	17-Jul-14
6495 Huron Church Line	Solar PV	8.6	MALDEN	24M7	01-Oct-14
8910 Malden Rd	Solar PV	8.6	KEITH	23M5	21-Jan-15
6435 Huron Church Line	Solar PV	10	MALDEN	24M7	14-Jan-15
410 Huron Street	Solar PV	5.16	KEITH	23M4	26-Mar-15
630 International Ave.	Solar PV	8.6	MALDEN	24M9	16-Apr-15
123 Gore St.	Solar PV	10	KEITH	23M3	11-Sep-15
6 Wallace	Solar PV	5.6	LEAMINGTON	393M24	01-Oct-15
1505 Durocher	Solar PV	9.5	MALDEN	24M7	03-Nov-15
1450 Outram Dr.	Solar PV	8.6	MALDEN	24M9	18-Jun-15
151 Superior St.	Solar PV	7.96	KEITH	23M4	30-Jul-15
600 Michigan Ave.	Solar PV	10	KEITH	23M4	06-Jan-16
1214 Kenwick Way	Solar PV	10	MALDEN	24M7	23-Mar-16
436 Richmond St	Solar PV	10	MALDEN	24M7	07-Mar-16
122 Sturgeon Meadows	Solar PV	7.25	LEAMINGTON	393M27	07-Jan-16
132 Danforth Ave.	Solar PV	9.25	LEAMINGTON	393M24	26-Nov-15
66 Venetian Dr.	Solar PV	10	KEITH	23M3	29-Jan-16

1885 Suzanne St.	Solar PV	4.75	MALDEN	24M9	28-Jan-16
3 Hainer Court	Solar PV	10	MALDEN	24M7	15-Apr-16
2936 Front Rd.	Solar PV	10	KEITH	23M4	04-Apr-16
1019 Heritage Dr	Solar PV	10	MALDEN	24M9	10-May-16
1840 Meagan Dr	Solar PV	10	KEITH	23M5	17-Mar-16
285 Maple Ave.	Solar PV	10	MALDEN	24M9	28-Apr-16
8775 Malden Rd	Solar PV	10	KEITH	23M5	07-Apr-16
32 Alderton	Solar PV	10	LEAMINGTON	393M24	09-Jun-16
574 Michael Cres	Solar PV	9.5	KEITH	23M5	23-Jun-16
1011 Heritage Drive	Solar PV	10	MALDEN	24M9	04-Aug-16
28 Wakefield Avenue	Solar PV	10	LEAMINGTON	393M24	09-May-16
219 Pacific Ave.	Solar PV	6.75	MALDEN	24M7	11-Oct-16
27 Bruce Ave.	Solar PV	10	LEAMINGTON	393M27	27-Oct-16
17A Bruce Ave.	Solar PV	10	LEAMINGTON	393M27	19-Dec-16
176 Meloche Rd	Solar PV	10	MALDEN	24M7	07-Jan-17
83 Danforth Avenue	Solar PV	7.6	LEAMINGTON	393M27	27-Apr-17
425 Superior St.	Solar PV	7.6	KEITH	23M4	06-Jun-17
516 Autumn Ridge Ave.	Solar PV	7.6	MALDEN	24M7	25-Sep-17
8529 Malden Rd	Solar PV	10	KEITH	23M5	19-May-17
299 Grondin St.	Solar PV	7.6	KEITH	23M4	31-Oct-17

63 Foundry St.	Solar PV	7.6	LEAMINGTON	393M24	16-Nov-17
5970 Lasalle St.	Solar PV	7.6	MALDEN	24M9	16-Nov-17
81 Maple Ave.	Solar PV	7.6	KEITH	23M5	28-Nov-17
4305 Betts Ave.	Solar PV	10	MALDEN	24M9	24-Jul-17
41 Sherwood Ave.	Solar PV	7.6	LEAMINGTON	393M24	07-Dec-17
670 Richmond St.	Solar PV	7.6	MALDEN	24M7	11-Dec-17
278 Kempt St.	Solar PV	10	KEITH	23M3	11-Sep-17
24 Hodgins St.	Solar PV	10	LEAMINGTON	393M24	17-Aug-17
5860 Canada St.	Solar PV	10	MALDEN	24M9	11-Sep-17
925 Elmgate Cres.	Solar PV	10	MALDEN	24M9	16-Oct-17
1110 Gabrieau St.	Solar PV	7.82	MALDEN	24M10	17-Sep-17
74 Antonio Crt.	Solar PV	10	LEAMINGTON	393M24	16-Nov-17
465 Donlon St.	Solar PV	10	LEAMINGTON	23M4	07-Nov-17
45 Windwood Dr.	Solar PV	7.6	LEAMINGTON	393M24	20-Dec-17
175 Simcoe St.	Solar PV	5	KEITH	23M3	12-Jan-18
26 Windwood Dr.	Solar PV	7.6	LEAMINGTON	393M24	17-Jan-18
1111 Mia Anne St.	Solar PV	7.6	MALDEN	24M10	07-Feb-18
107 Danforth Ave.	Solar PV	7.6	LEAMINGTON	393M27	15-Feb-18
25 Evans Ave.	Solar PV	7.6	LEAMINGTON	393M24	01-Mar-18
80 Shawnee Crt.	Solar PV	7.6	LEAMINGTON	393M27	01-Mar-18

75 Tennessee Cres.	Solar PV	7.6	KEITH	23M3	05-Mar-18
570 Gary Ave.	Solar PV	5	KEITH	23M4	05-Mar-18
25 Cherrywood Ave.	Solar PV	10	LEAMINGTON	393M27	29-Mar-18
109 Bratt Drive	Solar PV	10	MALDEN	24M7	23-Mar-18
60 Main St. South	Solar PV	7.6	KEITH	23M3	30-May-18
21 Cameo Dr.	Solar PV	5	LEAMINGTON	393M24	22-Mar-18
6029 North Woodmont Cres	Solar PV	10	MALDEN	24M9	11-May-18
1475 Sprucewood Ave	Solar PV	9.8	MALDEN	24M9	23-Mar-18
1595 Lyons Ave.	Solar PV	7.6	KEITH	23M5	16-Mar-18
330 Jolly Ave.	Solar PV	7.6	KEITH	23M4	30-Apr-18
2615 Cousineau Rd	Solar PV	7.6	KEITH	24M9	24-Apr-18
244 Fort St.	Solar PV	7.6	KEITH	23M3	22-May-18
325 Sacred Heart Dr.	Solar PV	7.6	KEITH	23M4	07-May-18
Total		**1556.33**			

Table 4 – REG Installations under the Net Metering Program

Address	Fuel Source	Rating (kW)	Station-TS	Feeder	Connection Date
22 Cherrywood Avenue, Leamington	Solar PV	10	LEAMINGTON	393M27	3-Mar-18
2260 Bondy Avenue, LaSalle	Solar PV	10	MALDEN	24M10	10-Oct-18
326 Burdick Crescent, Tecumseh	Solar PV	8.2	LAUZON	56M26	26-Jul-19
63 Robinson Street, Leamington	Solar PV	7.7	LEAMINGTON	393M24	6-Dec-22
12082 riverside Drive, Tecumseh	Solar PV	10	LAUZON	56M25	17-Mar-22
12458 Riverside Drive, Tecumseh	Solar PV	10	LAUZON	56M25	10-Nov-22

41 Sandwich St. South, Amherstburg	Solar PV	5.59	KEITH	23M5	24-Mar-23
141 Sandwich Street South, Amherstburg	Solar PV	7.2	KEITH	23M5	11-Apr-23
1900 Concession 6, LaSalle	Solar PV	99	MALDEN	24M10	14-Apr-23
1238 Kenwick Way, LaSalle	Solar PV	4.8	MALDEN	24M10	15-May-23
1225 Ashberry Place, LaSalle	Solar PV	10	MALDEN	24M9	30-Jun-23
330 Bouffard Avenue, LaSalle	Solar PV	9.9	KEITH	23M4	4-Oct-23
12710 Riverside Drive, Tecumseh	Solar PV	10	LAUZON	56M25	11-Dec-23
Total		**202**			

Table 5 – REG Applications In-Progress

Address	Capacity (kW)	Generator Type	Station-TS	Feeder	Year
103 Erie Street, Leamington	60	Solar – Net Meter	LEAMINGTON	393M27	2024
96 Princess, Leamington	25	Solar – Net Meter	LEAMINGTON	393M24	2024
1200 Southfield Drive, Tecumseh	200	Solar – Net Meter	LAUZON	56M26	2025
1250 Southfield Drive, Tecumseh	200	Solar – Net Meter	LAUZON	56M26	2025
11873 Tecumseh Rd E	100	Solar – Net Meter	LAUZON	56M26	2025
Total	**585**				

The number of REG connections over the five-year historical period is shown in Table 6. Approximately 2 new net-metering services have been installed each year. Essex Powerlines forecasts the trend of new net-metering projects depicted in Table 6 to continue through the 2025-2029 forecast period. There were no other types of REG connections over the five-year historical period shown in Table 6.

Table 6 – Connections for Services over the Historical Period (2019-2023)

Service	2019	2020	2021	2022	2023
	Count (#)	Count (#)	Count (#)	Count (#)	Count (#)
Net Metering - Solar	1	0	0	3	7

Essex Powerlines has produced a five-year forecast of future REG connections >10kW. For the period 2024-2028 projections have been based on:

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

Based on those factors, the five-year forecast in 7 below has been established with an anticipated connections over the next 5-year period.

Table 7: Forecast REG for 2024-2028

Year	Projected # of Connections	Installed MW
2024	2	0.085
2025	3	0.5
2026	2	0.1
2027	2	0.1
2028	2	0.1
2024-2028 Totals	**11**	**0.885**

SYSTEM ASSESSMENT TO IDENTIFY CONSTRAINTS

Essex Powerlines feeder thermal capacity constraints are dependent on HONI substations. Essex Powerlines has confirmed the thermal capacity available for REG connectivity on each distribution feeder from HONI's Station and Feeder Capacity Calculator and subject to change.

Based on the current availability for REG connectivity on each distribution feeder and the forecasted REG connections, Essex Powerlines has determined that there is sufficient thermal capacity to support the forecasted REG connections. Essex Powerlines is not proposing any capital investments at this time to increase thermal capacity on the distribution system.

FUTURE GROWTH AND ITS IMPACT ON REG CONNECTIVITY

The projected increase in our customer base to 10-20% of its current level in the next 10 years has required Essex Powerlines to expand and/or upgrade several circuits in it long term capital plan to meet new load requirements. This infrastructure investment will further enhance REG connectivity, thus enabling more Essex Powerlines customers to participate in the Net Metering program.

PROPOSED INVESTMENTS TO FACILITATE NEW CONNECTIONS

Essex Powerlines is not proposing any capital investments currently to mitigate constraints or increase thermal capacity on the distribution system. This plan is subject to change based on changing capacity restrictions of HONI substations.

APPENDIX E: IESO COMMENT LETTER

IESO response to Essex Powerlines Corporation REG Investments Plan 2025 – 2029

As part of the OEB's Filing Requirements for Electricity Distribution Rate Applications, a distributor must submit a letter of comment from the Independent Electricity System Operator (IESO) on its Renewable Energy Generation (REG) Investments Plan, which is part of its Distribution System Plan. On January 22, 2024, Essex Powerlines Corporation ("EPLC") sent its REG Investments Plan (Plan) to the IESO for comment. The IESO has reviewed EPLC's Plan and reports that it contains no investments specific to connecting REG for the Plan period 2025 – 2029.

The IESO notes that EPLC's service territory is within the Windsor-Essex region. The Needs Assessment for Windsor-Essex was published by Hydro One Networks Inc on February 15, 2023 indicating further regional planning was required for the region.[7] The IESO's Scoping Assessment Outcome Report outlining the planning approach for the region was published on May 17, 2023.[2] The report determined that an Integrated Regional Resource Plan (IRRP) be undertaken for the Windsor-Essex region. fsc

On Page 10 of 10 of its Plan, under the heading Proposed Investments to Facilitate New Connections, EPLC states that "EPLC is not proposing any capital investments currently to mitigate constraints or increase thermal capacity on the distribution system."

As EPLC has determined it requires no system investments to connect REG over the 2025-2029 Plan period, the IESO submits that no comment letter from the IESO is required to address the bullets points in the OEB's Filing Requirements for Electricity Distribution Rate Applications – Chapter 5, Section 5.2.2 Coordinated Planning with Third Parties[89].

The IESO appreciates the opportunity provided to review the REG Investments Plan of EPLC and looks forward to working together in further regional planning processes.

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[7] Hydro One's Need Assessment, February 15, 2023: https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/windsoressex/Documents/Needs%20Assessment%20https://www.hydroone.com/abouthydroone/CorporateInformation/regionalplans/windsoressex/Documents/Needs Assessment - Windsor-Essex - Final Report.pdf%20Windsor-Essex%20-%20Final%20Report.pdf [2] IESO's Scoping Assessment, May 17, 2023: https://www.ieso.ca/-/media/Files/IESO/Document-Library/regional-planning/Windsor-Essex/windsor-essex-20230517-scoping-assessment-reportand-outcome-report.pdf

[8] OEB's Filing Requirements for Electricity Distribution Rate Applications - Chapter 5, Section 5.2.2, page 10: https://www.oeb.ca/sites/default/files/Chapter-5-DSP-Filing-Requirements-20200514.pdf

APPENDIX F: 2022 Roof Condition Report

EMPIRE ROOFING CORPORATION

Toronto: 416-923-7663 London: 519-850-7663 Windsor: 519-969-7101

ROOF CONDITION REPORT

Date: October 18th, 2022

Location: 2730 No. 3, Oldcastle ON, N0R 1L0

Prepared for:

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5.36 INDEX

INTRODUCTION

Roof Composition

The focus of this report is on the roof areas, as high-lighted in yellow/red and illustrated in the attached satellite image above.

The existing roof consists of:

Item	Material
Ballast	None.
Membrane	2-ply Modified Bitumen Torched
Fibre Board	½ " Fibre Board
Insulation etc.	4" PolyIso
Vapour Retarder	Kraft Vapour Barrier
Deck Type	22-gauge Metal

Core Cut of Roof System

View of Metal Decking

Core Cut Patched

Roof Deck

We cannot comment on the condition of the roof deck. Upon inspection from the interior of the building, the roof deck looked to be in good shape with no signs of rust or deterioration.

Inspection

- Roof is still protecting the building but has exceeded its life expectancy.
- Severe cracking and "alligatoring" of the membrane.
- Improper pitch pockets on roof
- Multiple repairs made in several areas that are beginning to age.
- Curbs, pipes, and protrusions are beginning to delaminate at seams

__________(Initials)

Membrane is cracking and alligatoring due to age and weathering

Blisters forming in roofing membrane

SUMMARY & RECOMMENDATIONS

Design Criteria

We have evaluated the existing roof system using various testing methods with respect to:

- Building operations
- Existing roof deck
- Building`s structural components
- Thermal value requirements
- Wind uplift requirements
- Rooftop mechanical components
- Rainwater management

Based on our inspection, the test cut results, and the above considerations, we recommend a recover application. The test cut showed no signs of moisture, and the roof plys are in excellent condition to allow for a recover.

The new flat roof will consist of:

Item	Material
Membrane	60-MIL TPO (WHITE)
Recovery Board	High Density ½" ISOGARD HD
Insulation	Existing
Vapour Retarder	Existing

5.36.1.1.1.1.2 Example of recent TPO project.

DETAILS & CONDITIONS

Wall Details

The existing walls that surround the roof sections consist of typical parapets. New TPO membrane to be fully adhered to the existing prepared parapet substrates, and carried and over the parapet, to form a continuous seal of the roofing system. Pre-finished Standing- Seam Metal Capping shall be fabricated and installed along parapet walls once the new roof has been installed. Colour to be determined prior to fabrication.

Roof Drainage

Remove and replace all roof drains with new cast-iron type, c/w clamping rings, hardware, and removable strainers.

Irregular Roof Penetrations

Install new TPO pitch pans at all irregular protrusions, conduits, gas lines through roof, etc.

Fill new pitch pans with two-part pourable sealer.

The completed detail requires NO maintenance for the entire life expectancy of the roof.

Vent Stacks, Pipes, E

Install new pre-formed TPO pipe boots at all vent stack locations.

Install stainless steel clamping rings

Seal with manufacturer approved sealant.

Gas Lines, Supports

Place new gas line support blocks where required.

Installed 8' on centre and at all corners, joints, and junctions at gas lines.

Paint gas line in high gloss safety yellow as needed

DETAILED SCOPE OF WORK: TPO ASSEMBLY

1 DESCRIPTION OF WORKS

The works comprise the labor, materials, equipment, and services necessary to recover the existing roof and install a new roof assembly including high-density ISOGARD HD, TPO membrane and associated roofing and sheet metal work. ***Project is located at 2730 No. 3, Oldcastle ON***

2 GENERAL

2.1 All work to be completed in accordance with Manufacturer Project Design Guides.

2.2 All work to be completed to National Roofing Contractors Association Standards of which Empire Roofing Corporation is a member in good standing.

2.3 Empire Roofing Corporation to carry Workers Compensation Coverage.

2.4 All work to be completed in accordance with Labor requirements and policies for safe work practices on construction sites.

2.5 Empire Roofing Corporation to carry $10 million commercial general liability insurance.

2.6 Insurance certificate, WSIB certificate of clearance will be provided to owner in project documents prior to start of work.

2.7 In our experience building permits typically are not required to conduct roofing works provided structural changes are not part of the scope of work; as such, we have not included any costs for building or other permits in our proposal. Should any permit be required, of the cost of such will be the responsibility of the owner. (None anticipated)

2.8 Exterior washroom facilities, cranes, scaffolding, etc. to be provided and maintained by Empire Roofing Corporation.

2.9 There will be a pre-job meeting to discuss the following:

- Questions concerning the project work.
- To determine a materials delivery and set up area.
- To determine a project, start date.

3 ROOF PREPARATION

3.1 Prior to performing any roofing work, all roof top penetrations such as air intakes, drains, etc., will be plugged to prevent infiltration of roof debris into the plumbing system. All plugs will be removed at the end of each working day to prevent a backup on the roof and replaced prior to the next day start up.

3.2 During roofing operations, exterior surfaces of finished walls, etc., shall be protected with tarpaulins to prevent damage.

 __________(Initials)

3.3 All components removed from the designated roof areas will be properly disposed of

_________(Initials)

3.4 Removal of metal flashings, copings, etc., and disposal of same.

3.5 At the completion of each day's work the site will be left clean and free of debris with safety barricades, fencing or caution tape in place as required. The storage of any scaffolding and/or materials will be isolated to minimize any inconvenience to the building owners and tenants.

4 *INSULATION*

4.1 Re-use existing insulation.

4.2 **Install new ½" High Density ISOGARD-HD** over existing roof.

a) Mechanically fasten insulation boards to substrate using 3" galvanized plates and mechanical anchors. Fasteners to be placed according to Manufacturer's recommendations.

b) This insulation is designed for recover application and isapproved by the membrane manufacturer for use with their roofing system.

4.3 All ISOGARD-HD shall meet FM Class 1, and UL Class A Construction approvals.

5 ROOF MEMBRANE

5.1 TPO membrane: A thermoplastic single-ply waterproof membrane; its lap seams are fused together with heat which results in a continuous bonded seam as strong as the rest of the membrane. TPO demonstrates a strong resistance to shrinkage and embrittlement. It provides excellent weatherability and strong resistance to UV radiation, ozone, and common chemicals.

5.2 **Install: 60 mils thick White Reinforced TPO membrane** over entire roof surface in accordance with

manufacturer's specification requirements.

a) Allow the membranes to relax a minimum of 30 minutes.

b) Membrane shall be attached using mechanical fastening/invisiweld.

c) The fasteners to be properly engaged in the deck. Empire will use caution not to overdrive fasteners, which may reduce the pull-out value of the fastener. An electric screw gun with an automatic clutch control or an automatic installation tool shall be used. Once the tools have been set, all fastener installation will be consistent.

d) Seams made with an automatic welder to be a minimum of 1 ½" wide. Seams made with hand welders must be a minimum of 2" wide.

6 SUBSTRATE PREPARATION AND MEMBRANE FLASHINGS

6.1 Evaluate the substrate and the quality of all existing parapet/surrounding walls. The substrate must be smooth and secure to allow for adequate adhesion.

6.2 **Prepare existing parapet walls** to provide a solid surface to adhere TPO membrane.

6.3 Position TPO 6” from the angle break along the wall to be flashed. Apply TPO bonding adhesive at about the same time to both the membrane flashing and the surface to which it is being bonded to allow approximately the same drying time.

- **a)** Apply the adhesive by rolling it onto the mating surfaces evenly, avoiding globs or puddles.
- **b)** Make sure not to apply any adhesive to any area to be welded.

6.4 Complete splice between membrane flashing and the main roof sheet by hot air welding.

6.5 Flash all walls, curbs, pipes, and other protrusions with TPO flashing membrane.

7 ROOF DRAINAGE

7.1 **Remove and Replace** all roof drains with new cast iron type, c/w clamping rings, hardware, and removable strainers.

5.36.1.1.1.1.2.1 a) Owner responsible for all disconnections and re-connections.

8 <u>ROOFTOP HVAC/UNITS</u>

8.1 Existing mechanical equipment is installed in such a manner as to limit proper roofing details to be carried out. As such, disconnecting/lifting of rooftop equipment may be required.

a) Disconnecting and reconnecting units to be done by owner.

9 GAS LINE SUPPORTS

9.1 Install new gas line supports as required, 8’ on center and at all corners of gas lines.

10 METAL FLASHINGS

10.1 **Fabricate and install 26g. pre-finished metal flashings** at all parapet and counter-flashing locations.

- **a)** Install continuous hook strips at all parapet locations.
- **b)** All joints in metal flashings shall have standing seam details. (no caulking required)
- **c)** Install color-matched fasteners placed appx. 24” o.c. on the inside face of the flashing.

11 QUALITY ASSURANCE

11.1 Empire Roofing Corporation is an approved, licensed, and authorized applicator of membrane manufacturer.

11.2 Empire Roofing Corporation is a Firestone Master Contractor (only six (6) exist in Canada).

11.3 The work shall be executed by workmen skilled and trained in the application of TPO membrane and shall be under full time competent supervision.

11.4 Empire Roofing Corporation has been inducted to the Firestone Hall of Fame. Over the past 35 years of Firestone being in the roofing industry only 28 have been inducted worldwide.

11.5 Empire Roofing Corporation has been awarded the highest most sought-after awards in the roofing industry. (Platinum Master Contractor and the Best of the Best in Quality Awards).

11.6 Inspection by Manufacturer: Provide a final inspection of the roofing system by a Technical Representative employed by manufacturer.

11.7 Technical Representative shall not perform any sales functions.

11.8 Contractor shall complete any necessary repairs required for issuance of warranty.

12 WARRANTY

12.1 The membrane manufacturer will supply a **twenty (20) year materials warranty.**

12.2 The membrane manufacturer will supply **fifteen (15) year systems warranty** in accordance with published terms, conditions, and limitations.

12.3 Warranties shall be issued upon receipt once the owner has paid the Contract in full including any additional charges, costs and/or interest as set out herein.

13 SUBMITTALS

13.1 Manufacturer's Design Guides detailing membrane sheet and insulation attachment, insulation fasteners and membrane fasteners.

13.2 Submit current installation instructions and detail drawings being used in this project to the owner in accordance with the general requirements of this Division.

13.3 Submit MSDS Sheets and Technical Information Sheets on products to be utilized on this project.

13.4 Submit Contractor safety policy and documentation specific to the project requirements including Form 1000, Notice of Project (if applicable), WSIB Clearance Certificate as well as Insurance Certificate.

14 TOXIC & HAZARDOUS SUBSTANCES

14.1 For the purposes of the Environmental Protection Act (Ontario) and all other applicable legislation, the owner shall be deemed to have control and management of the place of work, shall take all necessary steps to determine whether any toxic or hazardous substances are present at the place of work, including the retaining of qualified and licensed consultants and engineers and shall provide Empire Roofing Corporation with a written report of all such substances and their locations prior to the commencement of work.

14.2 Not withstanding the above, if Empire Roofing Corporation encounters toxic or hazardous substances at the place of work or has reason to believe that toxic or hazardous substances are present at the place of work have not been dealt with as set out above to its sole satisfaction and as required by all applicable legislation, Empire Roofing Corporation shall have the right to immediately cease the work and shall inform the circumstances to the owner in writing. The work shall not thereafter be resumed until the owner has taken all such steps to remove the toxic or hazardous substances to the sole satisfaction of Empire Roofing Corporation or otherwise satisfy Empire Roofing Corporation that the place of work does not contain toxic or hazardous substances.

15 DELAYS

15.1 Empire Roofing Corporation shall:

a) Not be responsible for any delays attributed to weather conditions.

b) Not be responsible for any delays and/or defaults due to any causes beyond Empire Roofing Corporation's control including not limited to, acts and/or omissions by the owner, the owner's agents, employees, servants, representatives, other contractors or sub-contractors or anyone at the place of work not in the employ of, at the invitation of, or under the control of Empire Roofing Corporation nor shall Empire Roofing Corporation be liable for any delays and/or defaults due to matters beyond its control, including but not limited to, fire, lightning, tempest, flood, war, acts of God, strikes, lockouts, accidents, acts of government and unavailability of materials or labour.

PRICING: TPO ROOF ASSEMBLY

OPTION	SYSTEM TYPE	INSULATION THICKNESS, LTTR VALUE	WARRANTY	MANUFACTURER	PRICE
Roof Area #1	60 Mil TPO	Re-use existing	(20) Year Membrane (15) Year Systems	Firestone / IKO	**$57,244.00 + HST**
Roof Area #2	60 Mil TPO	Re-use existing	(20) Year Membrane (15) Year Systems	Firestone / IKO	**$21,323.00 + HST**
Areas #1 and #2 (simultaneously)	60 Mil TPO	Re-use existing	(20) Year Membrane (15) Year Systems	Firestone / IKO	**$76,067.00 + HST**

NOTES

- Price valid until , Dec 1st, 2022.
- Plumbing and mechanical connections by owner (if required)

Signature:______________________ Date: ______________________

 __________(Initials)

5.36.2 TERMS & CONDITIONS

A) Empire Roofing Corporation will not be altering the building structure or the existing slope of the roof deck in any fashion. Drainage of the new roof replacement may increase or decrease, depending on the weight removed. Empire Roofing Corporation will not be held responsible for any ponding of water. However, on request, a quotation for a custom-designed tapered insulation system to increase positive roof drainage will be supplied. (initials)

B) During roof replacement operations, dust, moisture and debris may be released from the existing roof or dislodged from the underside of the structural deck. This quotation does not include for the protection of the interior fixtures or goods. Protection may be done by the owner/tenant or by Empire Roofing Corporation at an additional cost._(initials)

C) Plumbing Connections by owner______(initials)

D) If rusted or rotted decking is encountered during the re-roof operations, it shall be removed and replaced immediately so as not to hold up the roofing crew and minimize exposing the building's interior to inclement weather. The cost of said repairs shall be $12.00/sq foot. Photographs documenting the areas shall be provided with invoice. Further approval shall not be required by the owner to proceed. n/a (initials)

E) Empire Roofing Corporation will not be responsible for any damages due to water penetration caused by plugged, blocked or improperly installed or maintained drains and/or any other plumbing installations, or gutters. Any extension or modification of existing plumbing connections to accommodate new roof drains and/or roof system is not covered under the terms and conditions of this proposal. All plumbing works are to be carried out by the Owner.______(initials)

F) The removal, replacement and/or reinstallation of any heating, air conditioning, mechanical equipment, satellite dishes, solar panels or equipment, or any other installations shall be the responsibility of others at the expense of the owner._(initials)

G) Empire Roofing Corporation shall not be held responsible for leaks occurring as a result of failures and/or deficiencies in wall-cladding, masonry, architectural panels, windows etc. ____________(initials)

H) This quotation is based on normal working hours. Any overtime work required due to building occupants scheduling restrictions will be extra to this quotation._(initials)

I) The customer shall provide rights of entry for Contractor and/or their representatives and necessary permissions in order for Contractors and/or their representatives to complete its services.
(initials)

J) All contracts subject to final approval by Empire Roofing Corporation's Accounting Department/Management.___________(initials)

K) Payment terms are attached to this proposal as Schedule "A"._(initials)

L) Typically, permits are not required for re-roofing projects. We have not allowed for any permits. If, however, permits are required, they shall be the responsibility of the Owner.

(initials)

M) Traversable transport truck and crane access shall be provided around entire building perimeter as required for the loading/off loading of materials. Should this not be available, additional material handling charges will apply and be calculated on a case-by-case basis. (initials)

SCHEDULE "A"

Agreement of Payment Terms - This Schedule is attached to and forms part of the Contract. Accounts

Payable Contact :____Phone # ______________________

Email Address:____Fax # ________________________

Bill to Address: ____

Job Address: ____

Building Owner Name/Company: ____

Mailing Address: ____

Customer Initials
Initial ALL terms pertaining to the project below

5.36.2.1.1.1.1.1 Payment terms shall be as follows: ______________________________________

1. Commencement/ Start-Up: *5.36.2.1.1.1.1.2* _______*25%*_______
   Due upon material being delivered on site

2. Progress Draws: ________________

3. Substantial Completion: ________________
   Due upon completion of roofing work (less 5% for metal work)

4. Final Draw *5.36.2.1.1.1.1.3* _______*75%*_______
   30 days

5. ______days after substantial completion ________________

6. ______days after substantial completion ________________

It is understood that both Parties have reviewed and acknowledged receipt of this Agreement. It is also understood that if the Customer defaults on payment(s) a 1.5% per month (18% per annum) service charge will apply to the invoice(s) in question.

Authorized by: (Print Name)___________________________________Date: _________________________________

Signature:____Position: _______________________________

Why Deal with Empire Roofing Corporation:

- ✓ Detailed proposals eliminate extra/hidden charges
- ✓ Thorough roof study by an engineer to ensure the right design for your building's roof
- ✓ The most trained, skilled, and awarded labour force in the industry
- ✓ Your new TPO roof has the lowest annual maintenance cost in the industry. Similarly repairs on TPO roofs are the most economical in the industry.
- ✓ Empire Roofing Corporation has been awarded the highest most sought-after awards in the roofing industry. (Platinum Master Contractor and Inner Circle of Quality Awards)
- ✓ We start on time and complete the project on time…. every time
- ✓ As the largest TPO installer in the nation, our buying power ensures you a fair price with exceptional value.
- ✓ Environmentally conscious products. Your new TPO roof, at the end of its life will **<u>not</u>** end up in a landfill, it is fully recyclable. It will end up as a dashboard in your car, fender, bumper, or sun deck.
- ✓ You can feel 100% confident that we will stand behind our work and our warranties.

5.36.2.1.1.1.1.4 Recently Completed TPO Project

APPENDIX G: 2016 Building Condition Report

APPENDIX H: EPLC’s Fleet Purchasing Policy

APPENDIX I: Example EPLC RFQ for purchase of a Fleet Vehicle