lakeland POWER

Distribution Ltd.

Distribution System Plan

Filed with

LPDL's 2025 COS

Historical Period: 2019-2024

Forecast Period: 2025-2029

[October 31, 2024]

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5.2 DISTRIBUTION SYSTEM PLAN

Lakeland Power Distribution Ltd ("**LPDL**") has prepared this Distribution System Plan ("**DSP"**) in accordance with the Ontario Energy Board's ("**OEB"**) Chapter 5 Filing Requirements For Electricity Distribution Rate Applications dated December 15, 2022 (the "**Filing Requirements**") in support of its 2025 forward test-year cost of service ("**COS**") rate application (the "**Application**"). LPDL retained Utilis Consulting Inc. ("**Utilis**") for the assistance and preparation of this DSP.

The DSP is a stand-alone document filed in support of LPDL's Application. LPDL submitted the last cost of service application in September 2018. Based on the following quote from the Ontario Energy board directions, this 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 2019 to 2024 which includes 2019 as the test year of the last DSP, with 2024 being the bridge year for this DSP, and a forecast period of 2025 to 2029, with 2025 being the test year of this DSP.

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

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

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

5.2.1 Distribution System Plan Overview

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

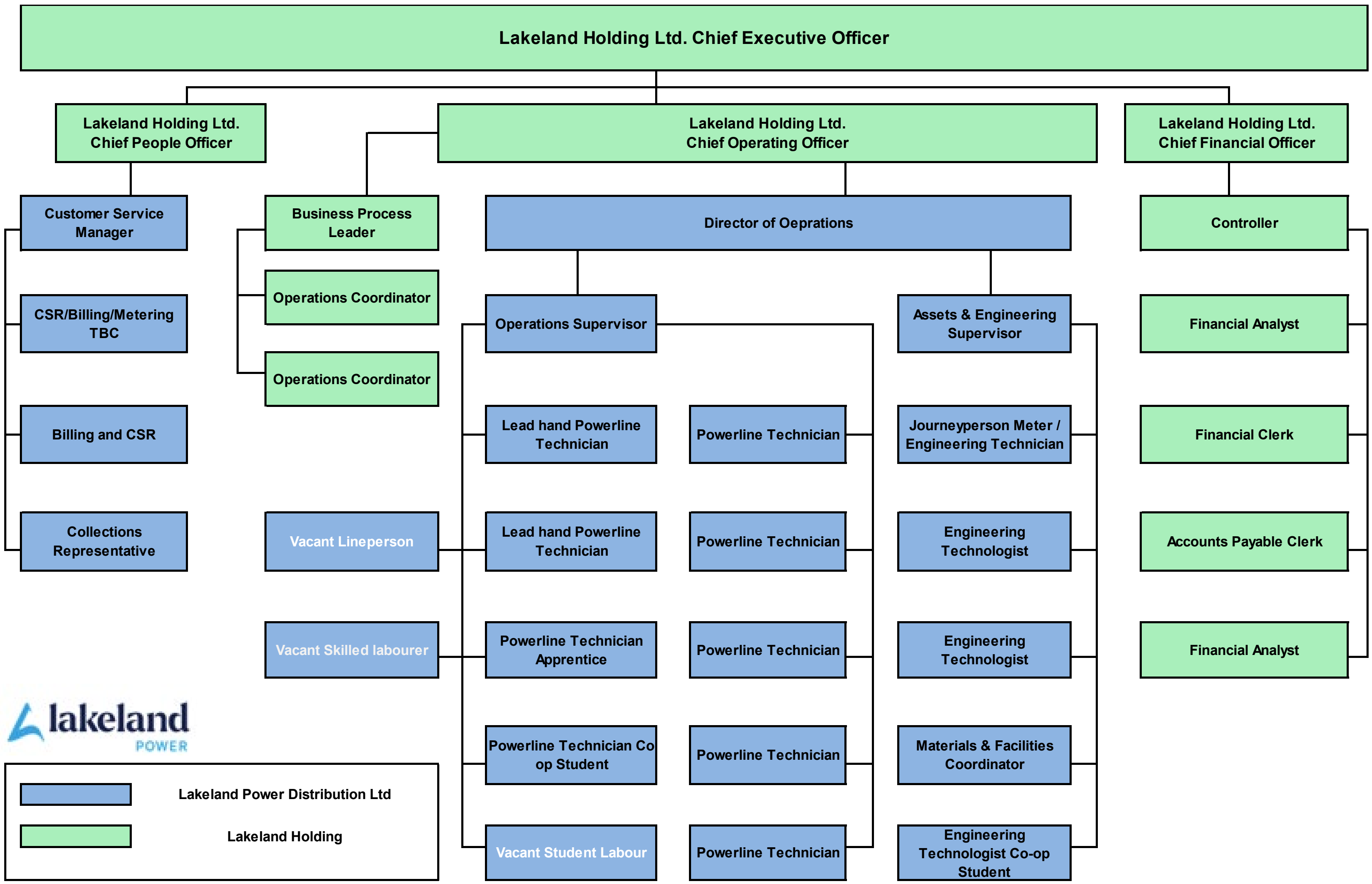
5.2.1.1 Description of the Utility Company

LPDL was formed in 2000, with the merger of Bracebridge, Burks Falls, Huntsville, Magnetawan and Sundridge utilities and a further merger in 2014 with Parry Sound Power. LPDL is a for-profit private corporation carrying on the business of distributing electricity to customers safely and reliably. LPDL is a subsidiary of Lakeland Holding Limited ("**LHL**"), which is governed by an independent Board of Directors. LPDL is a licensed Local Distribution Company ("**LDC**") holding distribution licence ED-2002-0540.

LPDL is a member of the Cornerstone Hydro Electric Concepts Association (CHEC), a cooperative that provides shared resources and encourages collaboration between its 15 LDC members representing more than 100,000 customers. LPDL's membership with Utilities Standards Forum (USF). provides access to a common set of design, construction and material standards. LPDL is also an active member of the Electricity Distributors Association (EDA) and the Municipal Electric Association Reciprocal Insurance Exchange (MEARIE) Group.

LPDL's 2024 organizational chart is illustrated in Figure 5.2-1.

Figure 5.2-1: LPDL 2024 Organizational Chart



5.2.1.1.1 *MISSION AND VISION*

Our mission is to distribute electricity safely and reliably to customers in Bracebridge, Burk's Falls, Huntsville, Magnetawan, Parry Sound and Sundridge. We are accountable to these towns that also are our shareholders. Our objective is to be one of Ontario's top performing distribution companies in both customer service and reliability.

LPDL's Vision: as a company, we strive to be an organization that:

- Provides a safe environment for our employees;
- Provides safe, reliable and economic services for our customers;
- Continues to prosper and be a good place to work; and
- Provides a safe environment for and maintains good relations with the general public and suppliers;
- All with consideration of the Environment.

5.2.1.1.2 *SERVICE AREA*

LPDL owns, maintains and operates the distribution system covering a 147 sq. km. service territory of which 128 sq. km. is rural. LPDL distributes electricity within the municipalities of Bracebridge, Burk's Falls, Huntsville, Magnetawan, Sundridge and Parry Sound.

Figure 5.2-3 through Figure 5.2-8 show the LPDL service territory within each of the municipalities.

LPDL owns a total of ten municipal substations ("**MS**").
Four of the substations are in the territory of Bracebridge:

- Bracebridge MS3
- Centennial MS
- Douglas MS
- Golden Beach MS

Two of them are located in Huntsville:

- Huntsville MS1
- Huntsville MS2

Four substations are in Parry Sound territory:

- Parry Sound MS1
- Parry Sound MS3
- Parry Sound MS4
- Parry Sound MS5

LPDL also services nine islands within in our service territory which are connected through submarine cables:

1. Peninsula Island - Bracebridge
2. Summer Island - Bracebridge
3. Frank island - Bracebridge
4. Ennis Island - Bracebridge

5. Auburn Island - Bracebridge
6. Sandspit Island - Bracebridge
7. Caisse Island - Bracebridge
8. McVittie Island - Bracebridge
9. Mill Lake/Limbert's Island - Parry Sound

Figure 5.2-2: LPDL’s Service Territory

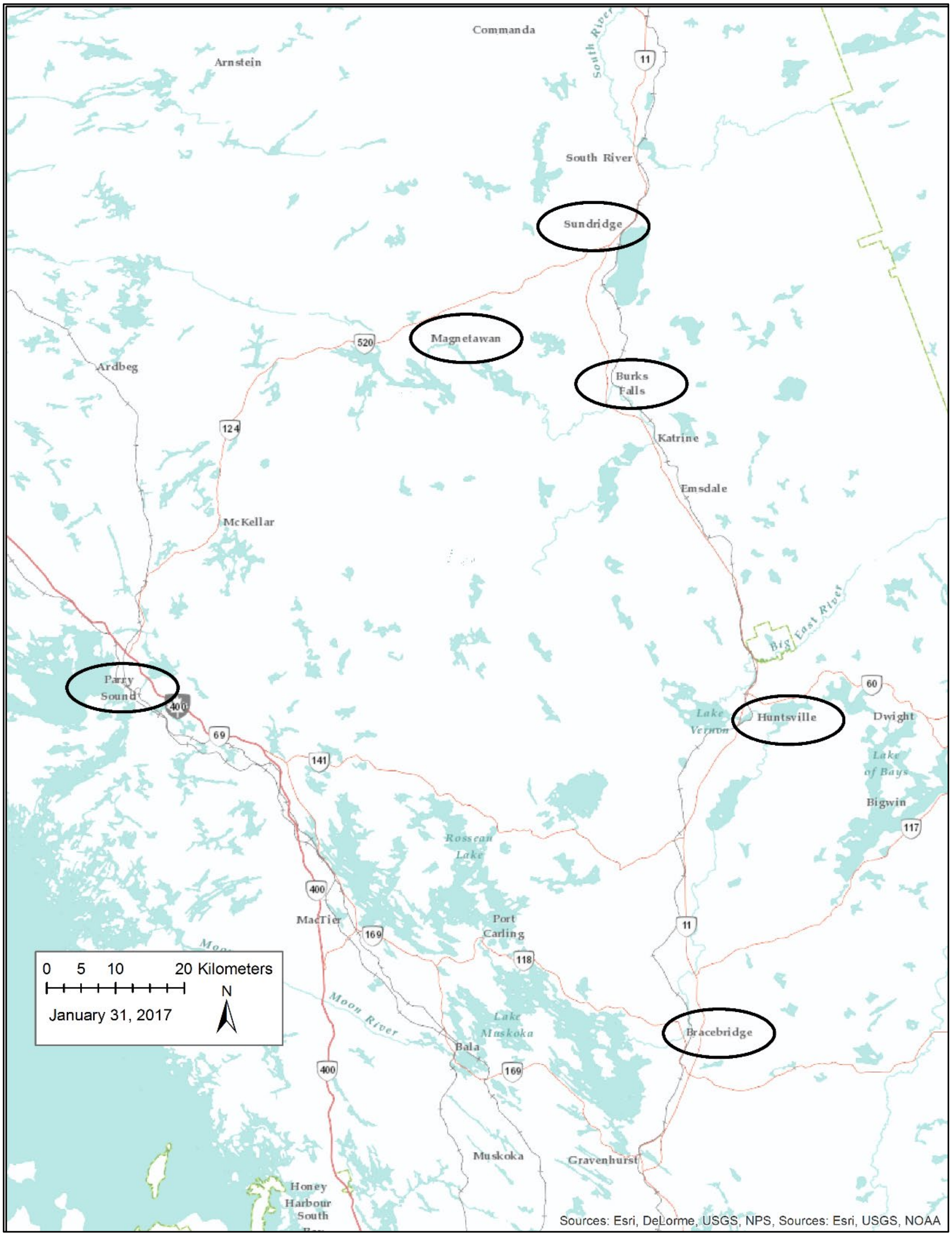


Figure 5.2-3: LPDL Bracebridge Service Territory

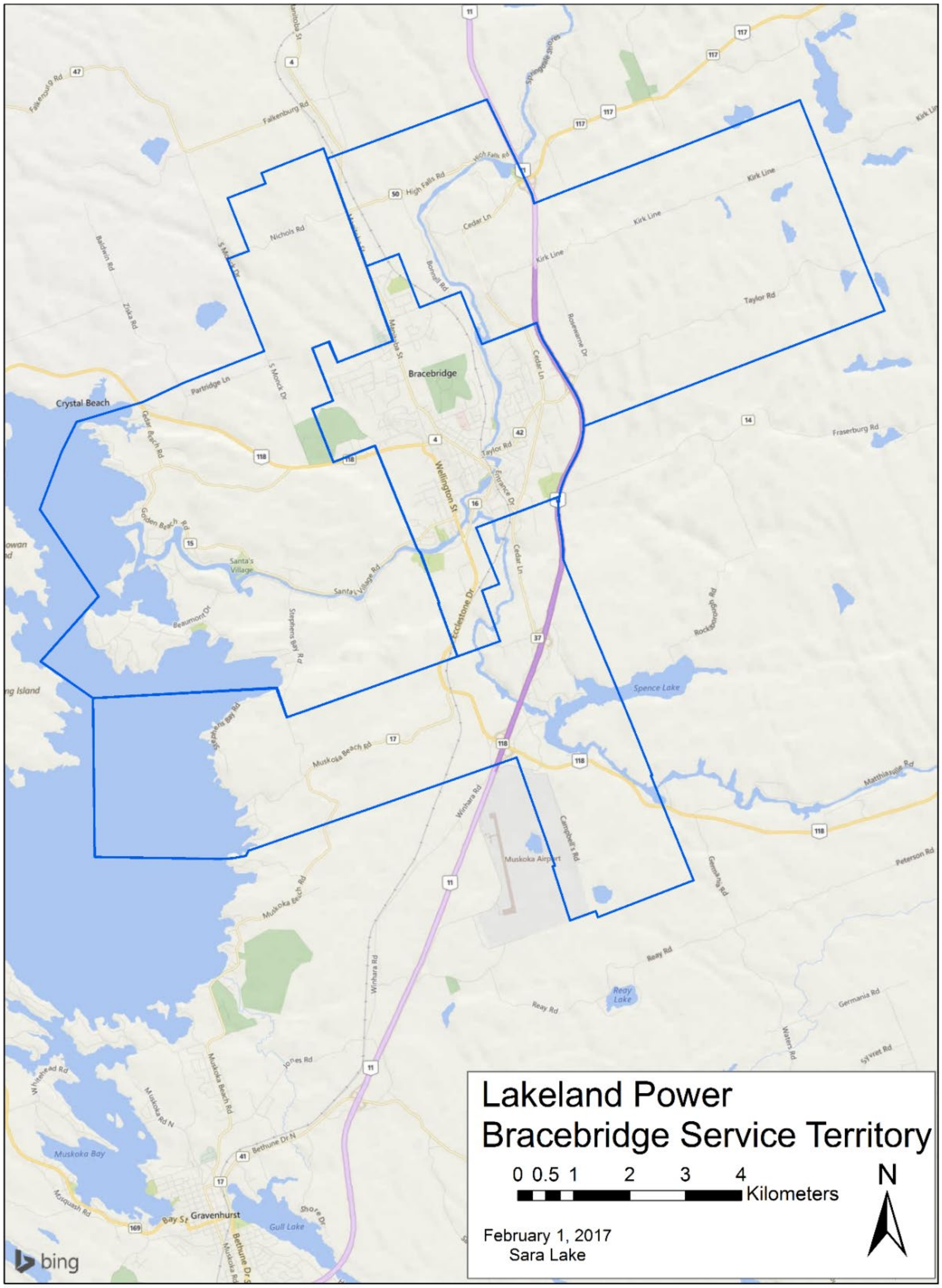


Figure 5.2-4: LPDL Burk's Falls Service Territory

Figure 5.2-5: LPDL Huntsville Service Territory

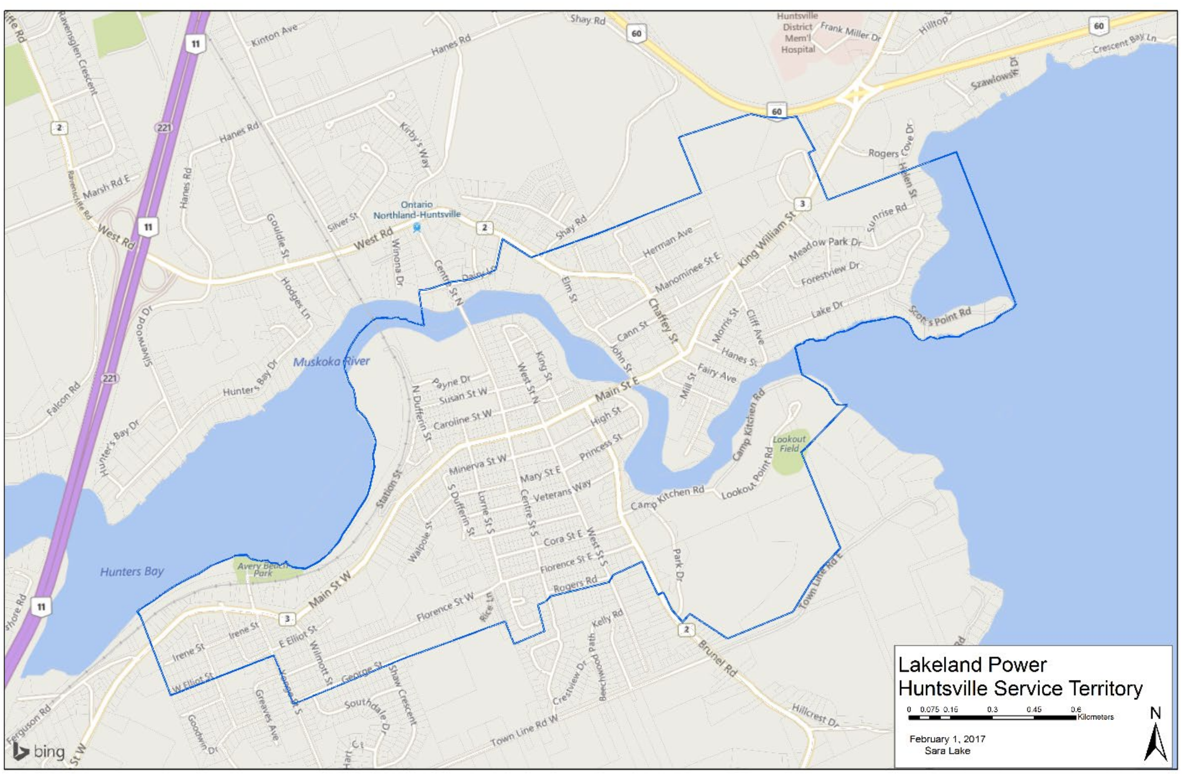


Figure 5.2-6: LPDL Magnetawan Service Territory

Figure 5.2-7: LPDL Parry Sound Service Territory

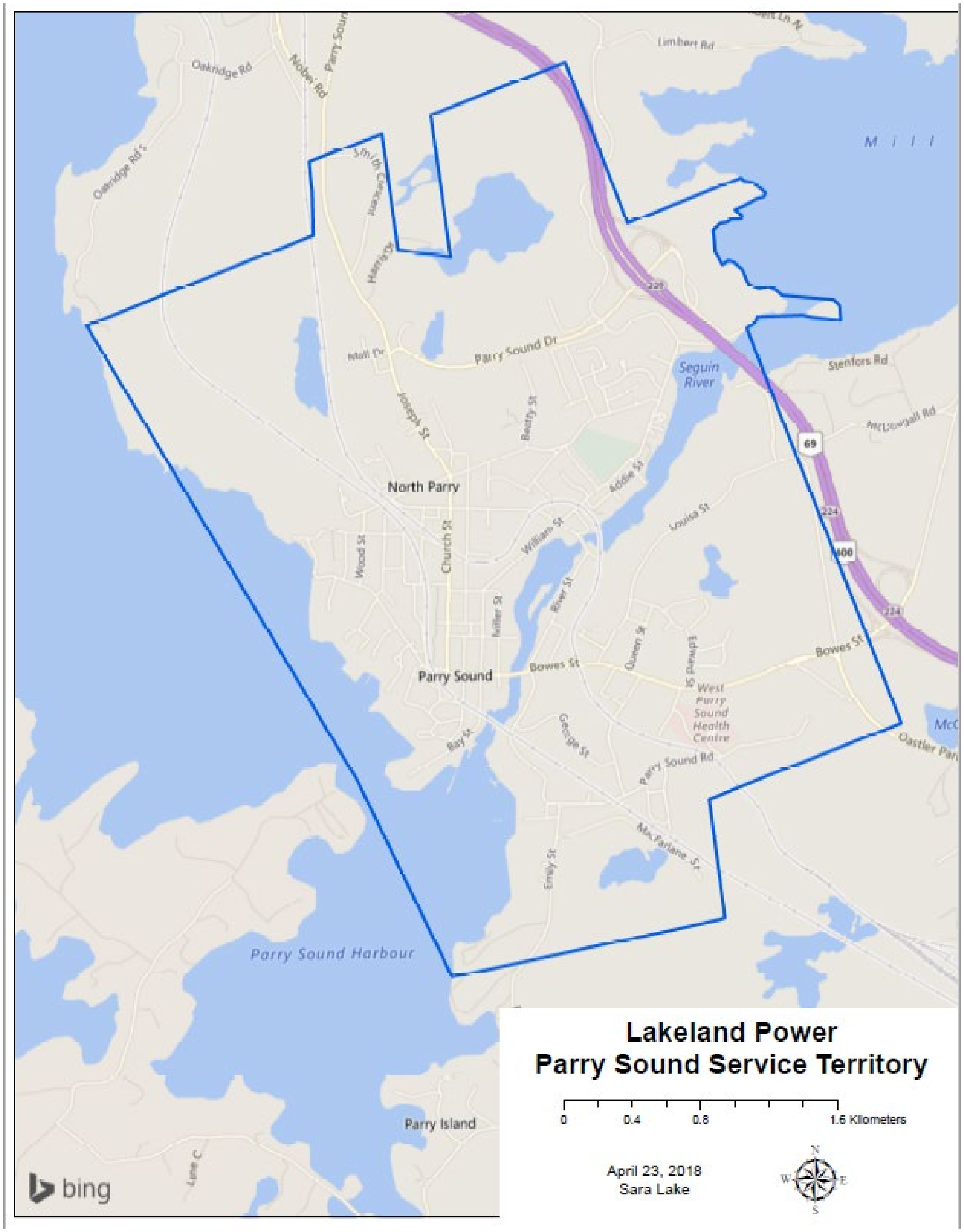
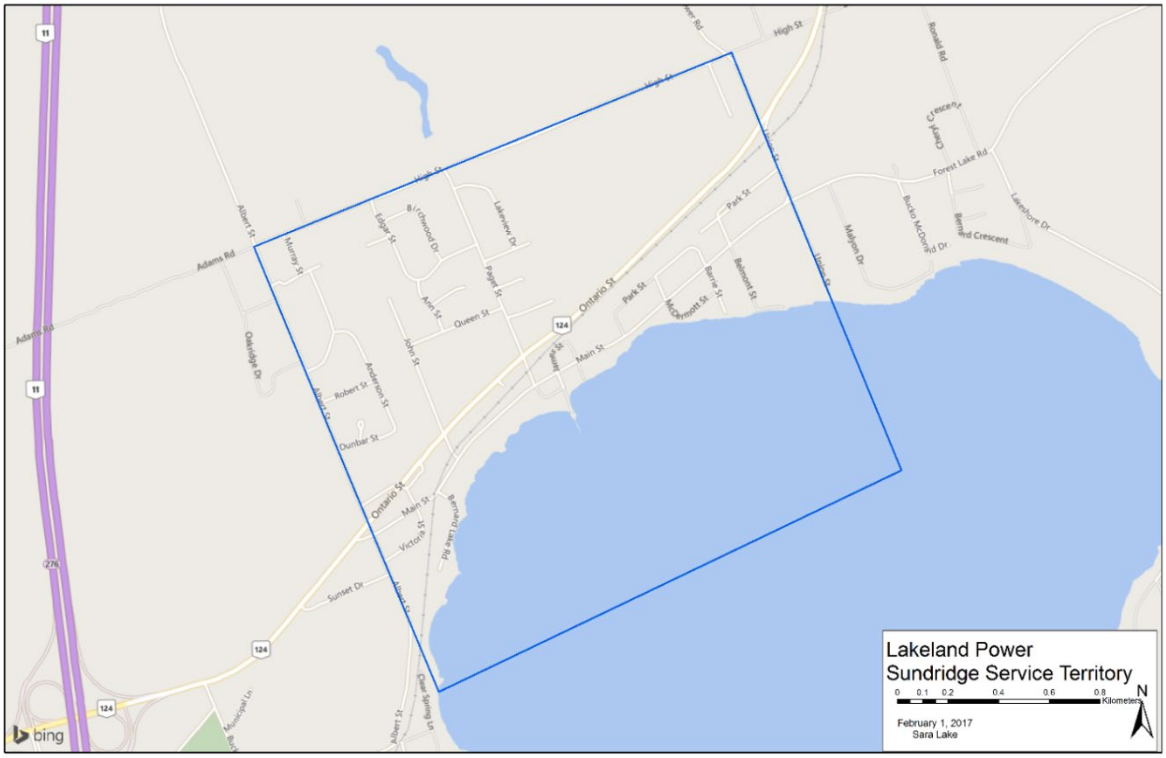


Figure 5.2-8: LPDL Sundridge Service Territory



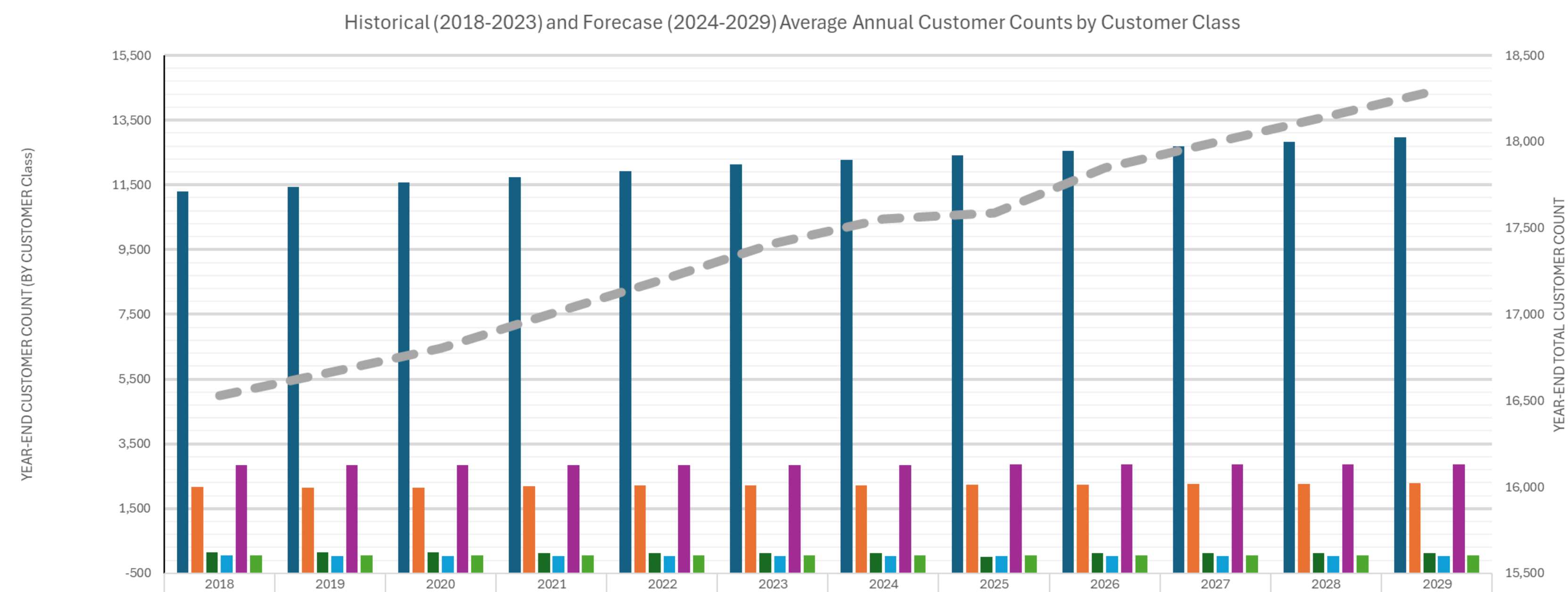
5.2.1.1.3 *CUSTOMERS AND LOAD*

LPDL distributes electricity to approximately 17,552 customers/connections, which includes 2,852 streetlight connections. 70% of the connections are residential accounts. LPDL has experienced a relatively steady minimal growth over the historical period and a similar trend is expected over the forecast period.

LPDL has six customer classes: Residential, General Service less than 50 kW ("**GS<50**"), General Service equal or greater than 50 kW but less than 5000 kW ("**50GS<5000**"), Streetlights connection, Sentinel lights connections, and Unmetered Scattered Loads ("**USL**").

Figure 5.2-9 breaks down the year-end customer counts by customer class for both historical (2019-2024) and forecast (2025-2029) years.

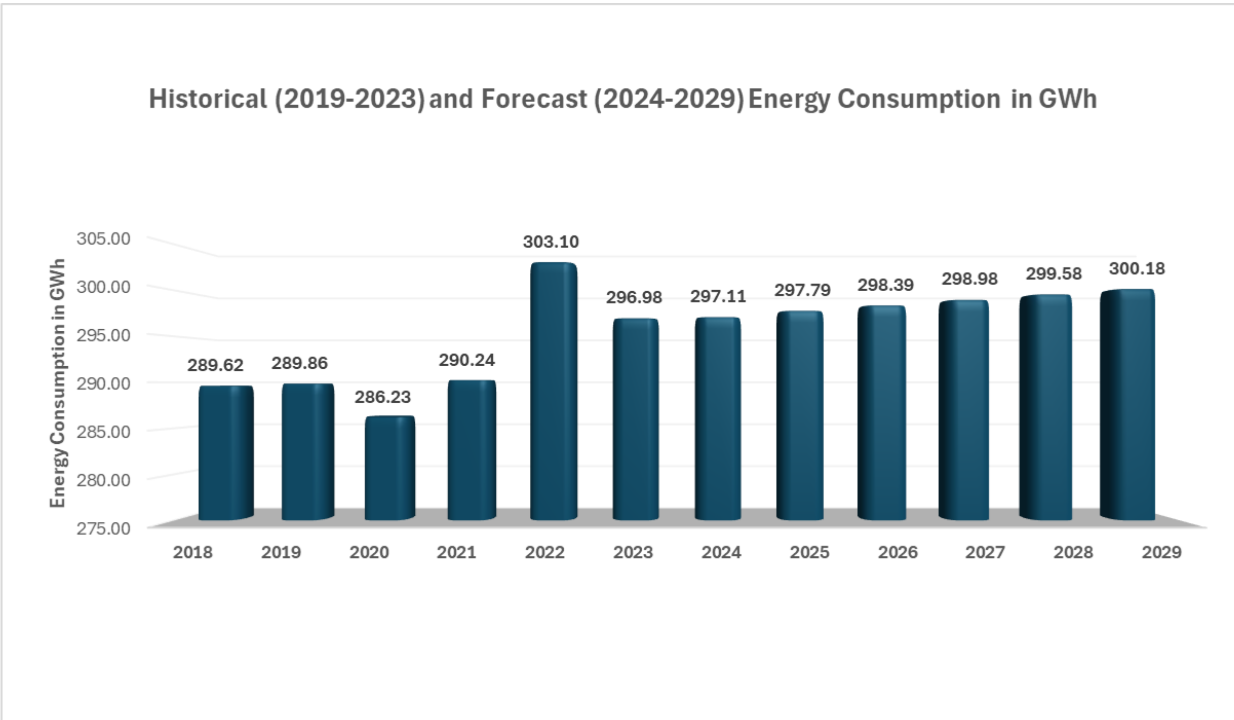
Figure 5.2-9: Historical and Forecast Average Annual Customer Counts by Customer Class



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential	11,289	11,430	11,566	11,726	11,912	12,125	12,262	12,400	12,540	12,681	12,823	12,968
GS<50	2,159	2,154	2,155	2,191	2,205	2,206	2,218	2,229	2,242	2,254	2,265	2,277
50SGS<5000	138	137	136	131	129	130	126	12	121	119	117	114
Sentinels	44	41	40	40	38	33	31	29	27	25	23	21
Streetlights	2,849	2,849	2,851	2,851	2,851	2,851	2,852	2,853	2,853	2,853	2,853	2,853
USL	51	55	56	65	64	63	64	65	64	64	64	64
Total Customer	16,530	16,666	16,804	17,004	17,199	17,408	17,553	17,588	17,847	17,996	18,145	18,297

Figure 5.2-10 Figure summarizes the actual energy delivered by LPDL to its customers from 2019 to 2023 and forecast energy consumption over the years of 2024-2029. Energy consumption per customer is expected to trend downward with energy conservation efforts and improved technology.

Figure 5.2-10: Historical (2019-2023) and Forecast (2024-2029) Energy Consumption



5.2.1.1.4 *Embedded Generation*

As of 2024, LPDL has a total of 66 Renewable Energy Generation ("**REG**") connections with 55 connected microFIT, 5 connected FIT, 5 connected HCI and 1 RESOP connection representing a total installed capacity of 13,479kW in its distribution system. Table 5.2-1 lists the REG connections.

Table 5.2-1: List of Installed REG connections (2010-2024)

Contract Type	Technology Type	Town	Connection Date	Capacity (kW)
microFIT	Solar	HUNTSVILLE	2010-03-12	10
microFIT	Solar	HUNTSVILLE	2010-07-20	10
microFIT	Solar	BRACEBRIDGE	2010-12-17	10
microFIT	Solar	HUNTSVILLE	2011-01-19	10
FIT	Solar	BRACEBRIDGE	2011-05-06	60
microFIT	Solar	SUNDRIDGE	2011-06-21	10
microFIT	Solar	SUNDRIDGE	2011-06-21	10
microFIT	Solar	SUNDRIDGE	2011-06-21	10
microFIT	Solar	SUNDRIDGE	2011-06-21	10

Contract Type	Technology Type	Town	Connection Date	Capacity (kW)
microFIT	Solar	SUNDRIDGE	2011-06-21	10
microFIT	Solar	BRACEBRIDGE	2011-07-27	10
microFIT	Solar	BRACEBRIDGE	2011-08-23	10
microFIT	Solar	HUNTSVILLE	2011-09-21	10
microFIT	Solar	BRACEBRIDGE	2011-10-04	10
microFIT	Solar	BURKS FALLS	2011-11-02	10
microFIT	Solar	BRACEBRIDGE	2011-11-23	10
microFIT	Solar	MAGNETAWAN	2012-03-16	10
microFIT	Solar	BRACEBRIDGE	2012-03-20	10
microFIT	Solar	BRACEBRIDGE	2012-11-09	10
microFIT	Solar	BRACEBRIDGE	2012-11-20	10
microFIT	Solar	BRACEBRIDGE	2012-12-04	10
microFIT	Solar	BRACEBRIDGE	2012-12-04	10
microFIT	Solar	BRACEBRIDGE	2013-01-08	10
microFIT	Solar	BRACEBRIDGE	2013-03-26	10
microFIT	Solar	BRACEBRIDGE	2013-05-10	10
microFIT	Solar	BRACEBRIDGE	2013-05-28	10
microFIT	Solar	BRACEBRIDGE	2013-06-18	10
microFIT	Solar	BRACEBRIDGE	2013-07-09	10
microFIT	Solar	BRACEBRIDGE	2013-07-09	10
FIT	Solar	BRACEBRIDGE	2013-07-26	175
microFIT	Solar	BRACEBRIDGE	2013-07-30	10
microFIT	Solar	MAGNETAWAN	2013-08-09	10
microFIT	Solar	BRACEBRIDGE	2013-08-20	10
microFIT	Solar	BRACEBRIDGE	2013-09-05	10
microFIT	Solar	BRACEBRIDGE	2013-10-08	10
microFIT	Solar	BRACEBRIDGE	2013-10-15	10
microFIT	Solar	BRACEBRIDGE	2013-11-04	10
microFIT	Solar	BRACEBRIDGE	2013-12-13	10
microFIT	Solar	HUNTSVILLE	2014-01-14	10
microFIT	Solar	HUNTSVILLE	2014-01-24	10
microFIT	Solar	HUNTSVILLE	2014-01-24	10
microFIT	Solar	HUNTSVILLE	2014-10-02	10
FIT	Solar	BRACEBRIDGE	2014-10-03	134
microFIT	Solar	BRACEBRIDGE	2014-11-26	10
microFIT	Solar	BRACEBRIDGE	2015-03-24	10
microFIT	Solar	PARRY SOUND	2015-06-10	6.25
FIT	Solar	PARRY SOUND	2015-07-13	26
microFIT	Solar	BRACEBRIDGE	2015-07-20	10
FIT	Solar	BRACEBRIDGE	2015-08-10	100

Contract Type	Technology Type	Town	Connection Date	Capacity (kW)
microFIT	Solar	HUNTSVILLE	2015-08-18	10
microFIT	Solar	SUNDRIDGE	2015-10-30	10
microFIT	Solar	BRACEBRIDGE	2016-04-13	10
microFIT	Solar	MAGNETAWAN	2016-05-31	10
microFIT	Solar	MAGNETAWAN	2016-06-14	10
HCI (upgraded from 1200 kW to 2973 kW)	Hydroelectric	PARRY SOUND	2017-10-06	2973
microFIT	Solar	BRACEBRIDGE	2017-11-28	10
microFIT	Solar	BRACEBRIDGE	2018-03-02	10
microFIT	Solar	BRACEBRIDGE	2018-03-20	10
microFIT	Solar	BRACEBRIDGE	2018-07-12	10
microFIT	Solar	BRACEBRIDGE	2019-06-01	10
microFIT	Solar	HUNTSVILLE	2019-06-28	10
Net Meter	Solar	MAGNETAWAN	2022-08-08	7.6
Net Meter	Solar	BURKS FALLS	2019-04-26	30
Net Meter	Solar	PARRY SOUND	2023-11-14	7.68
Net Meter	Solar	HUNTSVILLE	2019-10-15	7.4
Net Meter	Solar	PARRY SOUND	2019-04-26	10
Net Meter	Solar	PARRY SOUND	2020-12-17	1757
Net Meter	Solar	PARRY SOUND	2019-04-26	192
Net Meter	Solar	BRACEBRIDGE	2024-04-17	10
Net Meter	Solar	BRACEBRIDGE	2022-11-18	10
Net Meter	Solar	BRACEBRIDGE	2024-05-01	10
Net Meter	Solar	BRACEBRIDGE	2024-05-14	8
Net Meter	Solar	BRACEBRIDGE	2023-12-07	9.77
Net Meter	Solar	BRACEBRIDGE	2024-04-10	22
Net Meter	Solar	BRACEBRIDGE	2024-06-18	10
Net Meter	Solar	BRACEBRIDGE	2024-01-22	6.3
Net Meter	Solar	BRACEBRIDGE	2020-10-05	10
Net Meter	Solar	BRACEBRIDGE	2019-04-26	2.51
Net Meter	Solar	BRACEBRIDGE	2023-12-21	6

5.2.1.2 Capital Investment Highlights

LPDL’s capital investments over the planning period have been aligned to the 4 categories of system access, system renewal, system service, and general plant outlined in the Filing

Requirements. Table 5.2-2presents LPDL's historical actuals and forecast expenditures for both capital and Operations & Maintenance ("**O&M**") categories.

Table 5.2-2: Historical capital expenditures and system O&M

CATEGORY	Historical ($'000)					Bridge
	2019	2020	2021	2022	2023	2024
System Access	1449	1392	2728	2126	2388	1600
System Renewal	1254	408	920	1326	1416	1220
System Service	410	194	239	288	506	240
General Plant	360	347	640	633	691	840
TOTAL EXPENDITURE	3473	2341	4527	4373	5001	3900
Capital Contributions	-902	-769	-2139	-1779	-1979	-900
NET CAPITAL EXPENDITURES	2571	1572	2388	2594	3022	3000
System O&M	$1,710.65	$2,131.99	$2,043.48	$2,438.22	$2,452.00	$2,666.00

Table 5.2-3: Forecast capital expenditures and system O&M

CATEGORY	Forecast ($'000)				
	2025	2026	2027	2028	2029
System Access	1130	1035	1040	1045	1045
System Renewal	1335	1300	850	1210	1280
System Service	775	1755	3105	810	860
General Plant	1030	485	565	565	475
TOTAL EXPENDITURE	4270	4575	5560	3630	3660
Capital Contributions	-800	-600	-600	-600	-600
NET CAPITAL EXPENDITURES	3470	3975	4960	3030	3060
System O&M	$2,811	$2,952	$3,099	$3,254	$3,417

Note: The 2024 Bridge Year values are actual from Jan-Sept and extrapolated through Dec to show the expected total for the entire year, for both capital and O&M projects.

Careful planning is necessary to ensure that LPDL remains reliable, sustainable and affordable for all customers. The 2025-2029 capital plan will enable LPDL to prudently grow and maintain its distribution infrastructure to meet future needs.

To maintain quality of service and reliability for our customers, LPDL has carefully balanced the capital plan spending for the forecast period. The substation project and replacing exiting substation transformers is as important as the day-to-day operations or unplanned events.

Each investment category is discussed in detail below:

5.2.1.2.1 *SYSTEM ACCESS*

LPDL's System Access investments are modifications (including the relocation of assets) to the distribution system that LPDL 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:

- Connecting residential, commercial, and industrial customers.
- Metering investment to connect new customers and comply with Measurement Canada guidelines.
- Connecting subdivision and townhouse lots.

In the historical period, LPDL saw an unexpectedly high level of system access driven by Bell's Fiber-to-the-home ("**FTTH**") initiatives. These initiatives involved substantial investments primarily funded by Bell.

During the consultation with Bell, it was communicated that while the FTTH projects under the Universal Broadband Fund (UBF) are nearing completion, there remain projects outside the scope of the UBF, as well as additional joint-use projects that will continue to progress.

LPDL anticipates that investment in System Access will decline following the completion of Bell's projects under UBF in 2025 but not substantially. Afterward, we foresee expenditures stabilizing.

Capital contributions to the System Access category are mainly for subdivisions and general service connections. The forecast trend for customer general service connections is very smooth, and several subdivisions that are expected in 2025-2029 are included in the capital contributions forecast. Based on on-going consultations with economic development and planning departments in our communities, there are no new industrial, commercial or institutional large customers expected. Existing large customers have not indicated any plans for increasing load significantly.

LPDL participates actively in the IESO led Integrated Regional Resource Planning activities and calculated that the forecasted load growth is minimal.

The historical numbers are skewed high due to the effects of the COVID-19 pandemic and the increase in connections resulting from the population migration from larger urban centres to smaller communities.

In addition, with the completion of the 4.16kV conversion project and recent distribution asset upgrades, there is now new infrastructure that reduces the costs associated with new connection requests. These projects have significantly contributed to reducing the customer contribution as the infrastructure is already upgraded, and therefore the capital contributions from the customers for new connections is forecast lower than in the historical period.

Forecast details for the System Access category can be found in Table 5.4-43.

5.2.1.2.2 *System Renewal*

System Renewal investments address assets at risk of failure, impacting reliability. LPDL uses its ACA (Figure 5.3-21) as a key input when planning necessary renewal investments.

Budgeting for System Renewal is enhanced by the improvements to the AM process. Using the results of the ACA, better determination of the necessary expenses can be determined.

Replacing old assets offers numerous benefits, including reduced maintenance costs and enhanced safety. Modern systems are more reliable, require less frequent repairs, and pose fewer hazards like electrical faults and fires. Additionally, new infrastructure supports environmental sustainability by being more energy-efficient.

Moreover, updated assets often come with advanced technologies, such as smart grid capabilities and automated fault detection, which streamline operations and reduce downtime for customers. These upgrades also enhance customer satisfaction by ensuring reliable and efficient service, demonstrating LPDL's dedication to high-quality service and meeting evolving customer needs.

Through these renewal projects, LPDL ensures its infrastructure meets current demands and is prepared for future challenges.

Based on needs identified in the Asset Risk Rating (Figure 5.3-21), primary underground cable replacements are planned for 2025, as well as the years 2028 and 2029. These strategic replacements will not only ensure the continued reliability and resilience of the electrical distribution network but also significantly enhance the overall safety and efficiency of our infrastructure by mitigating the risks associated with aging and potentially faulty cables.

For instance, the replacement work planned for Westvale Drive is primarily driven by LPDL's Asset Condition Assessment ("**ACA**"), which has identified several high-risk cables in need of urgent attention. Additionally, this initiative will provide the secondary benefit of reducing the load on substations owned by Hydro One Networks Inc. ("**HONI**"), thereby optimizing the distribution network's performance and capacity.

Similarly, the Meadow Heights Drive replacement project, also steered by the findings of LPDL's ACA, will offer multiple advantages. Apart from addressing the immediate needs of replacing deteriorating cables, this project will further contribute to the reduction of load on HONI-owned substations. This will lead to a more balanced and efficient distribution network, ultimately improving service reliability for customers and decreasing the likelihood of interruptions.

Moreover, these proactive cable replacement efforts reflect LPDL's ongoing commitment to maintaining and enhancing the quality of service provided to our customers. By investing in robust infrastructure upgrades, we aim to deliver uninterrupted and high-quality electricity services, support future growth, and ensure that our system remains adaptable to emerging technologies and increasing energy demands.

Throughout the forecast period, LPDL will continue the systematic conversion of systems from 4.16kV to 27.6kV in Bracebridge, ultimately decommissioning its last remaining 4.16kV substation. While these projects offer several advantages, the 4.16kV conversions in Bracebridge are classified as System Renewal due to the replacement of our oldest and most at-risk assets. This initiative aims to reduce line losses, increase capacity to meet rising electricity demands, enhance redundancy between feeders, and improve the flexibility of the 27.6kV system.

LPDL will strategically reduce system renewal expenditures in 2025 to prioritize and support the completion of 4.16kV conversions. Historical figures on pole replacement average 100-150 replacements per year. On-going physical asset condition assessment on poles are expected to continue this trend.

Forecast details for the System Renewal category can be found in Table 5.4-44.

5.2.1.2.3 System Service

5.2.1.2.3.1 Distribution Automation

Expenditures in the System Service category are driven by the need to ensure that the distribution system continues to meet operational objectives (such as reliability, grid flexibility and distributed energy resource (DER) integration) while addressing anticipated future customer electricity service requirements (i.e.: station capacity increases, feeder extension, etc.). The investments comprising the System Service expenditures include station rehabilitation projects as well as several switch installations, restringing of line and commissioning projects, installation of fault indicators, protection and control devices and communication improvements.

LPDL is committed to ongoing investments in SCADA systems and grid automation, both at our substations and at the feeder level. These strategic investments have already demonstrated significant benefits, including enhanced switching capabilities and reduced restoration times.

Moreover, the implementation of advanced automation technologies ensures a higher degree of operational efficiency and reliability. By automating routine tasks and enabling remote monitoring and control, we can swiftly address potential issues, thereby minimizing service disruptions and improving overall grid stability.

In addition to operational improvements, these upgrades contribute significantly to cost savings by reducing the need for manual interventions and lowering maintenance expenses. The integration of smart-switches and automated systems also paves the way for future innovations, allowing for seamless incorporation of emerging technologies and adaptive responses to evolving energy demands.

Expenses include Recloser Installation/Replacement Project, at 12% of the System Service Budget. Further forecast details for the System Service category can be found in Table 5.4-45 and Table 5.4-46.

5.2.1.2.3.2 New 27.6kV Substation

A major planned investment into System Service is the construction of a new 27.6kV substation in Bracebridge. This will replace the 4.16kV Bracebridge MS3 – the only remaining 4.16kV substation remaining in that territory. Conversion work described in System Renewal is projected to be completed by 2026. Thus, construction of the substation is planned for the same year and continuing into 2027. This will be 41% of the total budget, with the majority of the costs expected in 2027.

The new 27.6kV substation will be serviced by a different HONI Transformer Station (Bracebridge TS) than our other 27.6kV substations, greatly decreasing the duration of loss-of-supply outages.

Furthermore, this new substation will enhance the overall resiliency of the electrical grid by improving redundancy and reducing the risk of widespread outages.

In addition to improving reliability, the new substation will also support future growth in the area by increasing the capacity to meet rising electricity demands. By incorporating advanced technologies, such as smart grid functionalities and automated fault detection systems, the substation will ensure a more efficient and responsive distribution system.

5.2.1.2.3.3 12.5kV Conversions in Parry Sound

Beginning in 2026, LPDL will commence the systematic conversion of systems from 4.16kV to 12.5kV in Parry Sound. In 2025, LPDL plans to install smart-switches at Parry Sound MS5, leveraging its available capacity throughout the forecast period. Several locations suitable for conversion work are also identified in our ACA as elevated risk, thus providing multiple benefits. In addition to reducing line losses and increasing capacity, this initiative will enhance grid stability and future-proof the infrastructure to accommodate future growth. Through the forecast period, this project will be 23% of the total System Service budget.

5.2.1.2.3.4 Capacity Upgrades

Through feeder-modelling and consultation with developers and Electric Vehicle Supply Equipment ("**EVSE**") installers, LPDL has identified critical areas in the north end of Parry Sound that require new conductors to meet the increasing demand. This includes a new subdivision, a high school, a recreation centre, two level-three EVSE charger locations, and several vehicle dealerships installing EVSEs. LPDL plans to commence this essential work in 2025, to support the electrification of transportation. This project will continue through 2027, and contributes to 11% of the category budget over the forecast period.

5.2.1.2.4 *General Plant*

Expenditures under the General Plant category are necessitated by the requirement to modify, replace, or augment assets that do not form part of the distribution system but are essential for supporting LPDL's ongoing operations. These include land, buildings, fleet, tools and equipment, rolling stock, and electronic devices along with operational software. LPDL's investments in this category encompass continuous upgrades to IT hardware and software (including Cybersecurity and GIS Utility Network Model), process enhancements, ongoing improvements to buildings and fixtures, the replacement of a bucket truck, and investments in miscellaneous tools and equipment.

Capital spending on buildings includes maintenance and updates to the LPDL Operations Centre in 2026, which houses the majority of the staff, the fleet, equipment and materials. With respect to fleet, major expenditures include a Double-Bucket Truck in 2025 and a dump truck in 2027/2028, as well as the other vehicles identified in the Fleet Management Plan. Tools and Equipment are expected to be replaced on an as-needed basis, as well as rolling stock which includes cables, conductors, transformers and poles that are used through the year and must be replaced. Electronic Power Quality Devices are also included in this category as they need to be repaired, replaced or upgraded.

This category of expenditures is further explained in Section 5.4.1.2.4. Forecast details for the General Plant category can be found in Table 5.4-47.

5.2.1.3 Key Changes Since Last DSP Filing

COVID-19 Pandemic: This global event changed much about the world, and those changes are persisting today, and are expected to impact the 2024-2029 forecast period. Significant increases in material and equipment costs, a strained labour market, and supply chain constraints may result in project delays. To accommodate these concerns, options are considered well in advance of the project start.

Asset Condition Assessment (ACA): LPDL has adopted new ACA procedures and software. While still in the early stages, LPDL is committed to dedicating additional resources towards enhancing our ACA practices. This initiative not only ensures improved accuracy in our assessments but also strengthens our capacity to anticipate and mitigate potential operational risks.

Project Prioritization Process: As indicated in the previous DSP, the Project Prioritization Process has been updated and enhanced using the new information available through the Asset Condition Assessment (ACA) software and procedures. More details on project prioritization criteria and weighting are available in Section 5.3.1.3.3.

Feeder Modelling: LPDL engaged a third-party consultant to model our systems in the municipalities experiencing the greatest growth, specifically Bracebridge and Parry Sound. This initiative not only ensures that our infrastructure can accommodate future demand but also identifies opportunities for enhancing energy efficiency and sustainability. This will help to improve power quality for customers by allowing different models to be executed and evaluated. This improves system performance and increases customer satisfaction.

PCB: All PCB-contaminated transformers have been removed from our system, and all associated storage facilities have been decommissioned.

27.6kV Substation: In the previous Distribution System Plan, LPDL outlined the intention to relocate Golden Beach MS to Bracebridge MS3 upon the completion of the system conversions, considering it a strategically central location. However, actual load growth has surpassed our initial forecasts. Coupled with the increased electrification demands, LPDL now plans to construct a new 27.6kV substation, bringing the total to four. This expansion not only accommodates the rising load but also enhances the reliability of our network and supports the integration of renewable energy sources.

Infrared Scanning: Since 2019, LPDL has recorded an increase in pole fires due to equipment failures. To address this, LPDL conducts annual infrared scanning of all infrastructure, focusing primarily on overhead switches and connections. Additionally, LPDL is systematically replacing all overhead porcelain switches with new polymer switches to further reduce the risk of pole fires.

Outage Management Improvements: LPDL has continued to enhance our Outage Management System ("**OMS**"), with Util-assist Inc. providing 24/7 OMS operations. Furthermore, we are in the preliminary stages of implementing TextPower to automatically notify customers affected by power outages. This initiative not only aims to improve customer communication during outages but also enhances our ability to respond swiftly and efficiently to service disruptions.

Cybersecurity: LPDL has significantly invested in cybersecurity, implementing robust firewall systems to safeguard critical infrastructure. This investment not only enhances data protection but also ensures the resilience and reliability of our operations against potential cyber threats.

Customer Engagement Processes: During the COVID-19 pandemic, LPDL re-evaluated how to best communicate and engage with customers electronically, as in-person meetings were no longer an option. LPDL applied and continues to adjust these learnings to better engage with customers in an increasingly digital manner, according to their preferences. This has increased customer satisfaction.

Battery Backup: LPDL has recognized the critical importance of battery backup systems in substations to ensure operational efficiency and maintain communication during outages, particularly in the event of supply interruptions. Consequently, LPDL is actively engaged in the installation of battery backup cabinets.

Centennial MS Failure: In June 2024, LPDL experienced a substation failure at our most critical substation, Centennial MS. While insurance is anticipated to cover the majority of the associated costs, we believe it is prudent to address this incident in our DSP. The failure occurred during a heatwave, which significantly challenged our ability to maintain voltage stabilization throughout this period.

Load Constraints in Parry Sound: In the previous DSP, constraint issues were identified by the Independent Electricity System Operator ("**IESO**") Regional Planning Committee, and the 2017 Long Term Energy Plan ("**LTEP**") in Parry Sound. Since then, LPDL worked with our subsidiary to commission a smart-grid and battery storage facility aimed at reducing constraint on the system. Furthermore, Hydro One has upgraded their Transformer Station, allowing for further development in the area.

5.2.1.4 DSP Objectives

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

- An overview of LPDL's Asset Management ("**AM**") objectives and processes.
- An overview of LPDL's managed assets and asset lifecycle optimization practices.
- An overview of LPDL's coordinated planning and engagement with third parties.
- A review of LPDL's operational performance in the historical period.
- A preview of LPDL's planned expenditures for the forecast period.
- A detailed justification of LPDL'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 LPDL to consider future customer needs and any required changes to its distribution system in advance. This approach enhances LPDL's ability to plan ahead and respond to evolving customer needs in a timely manner while managing and levelling the impacts of expenditures on consumer rates to maintain the affordability of its service.

LPDL's DSP has been prepared to support the four key objectives established in the OEB's Renewed Regulatory Framework ("**RRF**") for electricity:

1. **Customer Focus:** Services are provided in a manner that responds to identified customer preferences.
2. **Operational Effectiveness:** Continuous improvement in productivity and cost performance is achieved, and utilities deliver on system reliability and quality objectives.
3. **Public Policy Responsiveness:** Utilities deliver on obligations mandated by the government (i.e.: in legislation and regulatory requirements imposed further to Ministerial directives to the Board).
4. **Financial Performance:** Financial viability is maintained, and savings from operational effectiveness are sustainable.

To achieve these outcomes, LPDL is focusing on the following key areas:

- Building a safer distribution system for workers, the public, and key partners such as joint-use attachers
- Account for grid-resiliency when making informed decisions
- Ensuring system capacity to facilitate new customer connections
- Improving cost efficiency through planning and analysis
- Improving system reliability by deploying Distribution Automation and improvements to its SCADA technology
- Focus on the replacement of our most at-risk assets utilizing our ACA
- Supporting the deployment of distributed Renewable Energy Generation (REG)

5.2.2 Coordinated Planning with Third Parties

A distributor must demonstrate that it has coordinated infrastructure planning with customers (i.e.: large customers, subdivision developers, and municipalities), the transmitter (i.e.: Regional Infrastructure Planning), other distributors, the Independent Electricity System Operator (IESO) (i.e.: Integrated Regional Resource Planning), or other third parties where appropriate. A distributor should explain whether the consultation(s) affected the distributor's DSP as filed and, if so, a brief explanation as to how.
For consultations that affect the DSP, a distributor should provide an overview of the consultation and relevant material supporting the effects the consultation had on the DSP.
An overview of any consultation(s) should include: The purpose and outcome of the consultation; whether the distributor initiated the consultation or was invited to participate in it; and the other participants in the consultation process (i.e: customers, transmitter, IESO).

> *A distributor should file the most recent regional plan (Integrated Regional Resource Plan, Regional Infrastructure Plan). In the absence of a regional plan, the distributor should file a Regional Planning Status Letter from the transmitter. Further, a distributor is required to identify any inconsistencies between its DSP and any current Regional Plan. If there are any inconsistencies, the distributor shall explain the reasons why, particularly where a proposed investment in their DSP is different from the recommended optimal investment identified in the Regional Plan.*

5.2.2.1 Customers

5.2.2.1.1 *Purpose of the Consultation*

LPDL interacts with customers to share information, educate them, and gather their feedback on services, ensuring their needs and preferences are considered in planning. LPDL has held both formal and informal customer engagements historically.

5.2.2.1.2 *Initiation and Participation*

LPDL initiates consultations in the case of customer surveys, customer education and project consultations. Customer interaction is a fundamental aspect of the business. Customers proactively contact LPDL for consultation particularly when they are in need of assistance with planning for new loads or have concerns about infrastructure in their area such as deteriorated poles or trees that are hazardous to the line.

5.2.2.1.3 *Description*

5.2.2.1.3.1 Educational

LPDL frequently includes educational inserts with our billing statements and shares information on our website and social media platforms, including Facebook, X and Instagram. For a detailed overview, refer to Appendix J, which contains our Annual Social Media Report that highlights relevant data including posts and customer engagement metrics.

5.2.2.1.3.2 Electrical Safety Awareness (ESA) Survey

LPDL conducts a bi-annual survey to gauge customer Electrical Safety Awareness ("**ESA**"). The most recent survey, completed in 2024, was facilitated by Advanis, a consultancy firm. The survey aimed to gather comprehensive insights into customer perceptions and safety awareness regarding electrical services. Detailed outcomes of the ESA survey can be found in Appendix D.

5.2.2.1.3.3 Customer Satisfaction Survey (CSS)

LPDL conducts a CSS bi-annually, with the most recent survey completed in 2023. The last three year's results are included as Appendix C. This survey, facilitated by the consultancy firm Advanis, is essential for gathering detailed feedback from our customers about their experiences and satisfaction with our services. The insights obtained from the CSS are invaluable, helping to shape LPDL's strategic decisions and operational improvements. The feedback collected allows us to identify areas of strength and opportunities for enhancement, ensuring that we meet our customers' needs effectively and continue to provide high-quality serviicu

5.2.2.1.3.4 DSP SURVEY

LPDL conducted a DSP Survey, with the objective of determining our customer bases' priorities. LPDL received 462 responses in 2024, included as Appendix B. The results of the survey conveyed the following top five priorities, out of thirteen priorities provided to chose from, listed in order.

- Affordable cost of electricity
- Maintaining and upgrading equipment to ensure a safe and reliable electricity supply
- Storm hardening (physical infrastructure improvements increasing resistance to weather)
- New technology to support renewable energy generation, electric vehicles, etc.
- Improved outage communication (outage map, social media, etc.)

71% of respondents prioritized affordable cost of electricity. 70% of respondents chose maintaining a safe and reliable electricity supply as a priority. Storm hardening was a priority to just over half of respondents (53%), with the final two of the top 5 coming in at roughly 30% each. This shows the community focus is on affordability and reliability, in line with key priorities across the province. This prioritization is shown in LPDL capital projects such as recloser installation to improve reliability and line replacement to lower line loss, increasing efficiency and saving customer delivery charges.

5.2.2.1.4 *CONSULTATION OUTCOMES AND IMPACT ON THIS DSP*

LPDL has taken into account the five key priorities indicated by the customer satisfaction survey while planning our proposed projects for the forecast period. We have introduced a new section called Customer Preference in our project prioritization matrix.

The paramount concern for our customers was the affordability of electricity. This aligns with LPDLs vision of operating the business with efficiency and economic benefit to our customers. With respect to maintaining a reliable electricity supply, LPDL is committed to continuous improvements in its ACA results through projects such as pole and conductor replacement for 'very poor' assets. Many of the General Plant projects are also addressing reliability of the system. System Service projects such as recloser installation addresses both storm hardening and new technology priorities (such as EV charging) of our customers. Outage communication continues to be a focus with new outage notification processes and remains a budget item for future developments.

5.2.2.2 SUBDIVISION DEVELOPERS

5.2.2.2.1 *PURPOSE OF THE CONSULTATION*

The purpose of consultations with developers is to determine growth load requirements, planning requirements (such as with Municipalities, railways, or other utilities), and design requirements for the distribution system.

5.2.2.2.2 *Initiation and Participation*

Consultation is typically initiated by the developer as they begin preliminary designs or feasibility studies of their particular project. Participants are typically LPDL and the developer, but sometimes will include the Municipality or District planning departments, other entities such as Enbridge gas, water & sewer providers, telecom companies, or railway authorities when applicable.

5.2.2.2.3 *Description*

The manner in which consultations are held varies based on the developer's preference and their existing experience levels with LPDL. At a bare minimum, LPDL will meet with the developer to discuss all requirements of a new subdivision comprehensively. These requirements include, but are not limited to:

- Processes and Procedures: Detailed discussion on the steps to be followed, documentation required, and timelines involved from initiation to completion.
- High-Level Discussions: Overview of the project's scope, potential challenges, and strategic goals to ensure alignment between all stakeholders.
- Agreements: Contractual obligations, service agreements, and any other necessary legal documentation to formalize the partnership.
- Specifications and Design Requirements: Review of technical specifications, engineering designs, and compliance with regulatory standards to ensure the project meets all necessary criteria.
- Economic Evaluation: Comprehensive financial analysis including cost estimates, budget allocations, and economic feasibility to ensure the project is financially viable and sustainable.

5.2.2.2.4 *Consultation Materials*

Outcomes of these consultations include, but are not limited to:

- Detailed maps illustrating the distribution system layout
- Preliminary designs, if available, to provide a visual and technical overview of the project
- Necessary forms and agreements to formalize the consultation and project commitments
- Comprehensive specifications detailing the technical requirements and standards to be met
- Contact information for all involved parties to facilitate ongoing communication and coordination

5.2.2.2.5 *Consultation Outcomes and Impact on this DSP*

Consultation with developers gives LPDL an invaluable insight into potential load growth in key areas of its service territory. Using the insight, LPDL accounts for the expected growth during budgeting and project prioritization. For example, a portion of the justification for the Isabella St. re-conductor project comes from consultation with a developer in the Parry Sound area who plans to further develop the north end of the town.

5.2.2.3 Municipalities

5.2.2.3.1 *Purpose of the Consultation*

The primary purpose for LPDL to consult with Municipalities in our territory is to meet the requirements of the Electricity Act. Municipalities of LPDL's service territories are shareholders of the company, and also customers, making them stakeholders on several levels.

In addition, consultation with municipalities generates several benefits such as:

- Efficiencies realized due to coordinating efforts. For example, replacement of underground infrastructure may be in-line with plans for water and/or sewer replacements. This often leads to increased cost efficiency from both parties such as the cost of trenching, road crossings, and remediation work. This also carries the benefit of being less disruptive to residents in the area, resulting in greater customer satisfaction.
- Knowledge of when and where road widening projects may occur. This will be considered when prioritizing projects. For example, our ACA process may recommend replacement of the poles on a street in 2025, but we have knowledge that the road will be widened in 2027 so we may choose to delay the project.
- Mitigate potential conflicts such as with planned infrastructure work by other utilities and telecom companies.

5.2.2.3.2 *Initiation and Participation*

LPDL meets with shareholder and neighbouring municipalities on an as-needed basis, and on a defined schedule appropriate to the project during project implementation. Shareholder municipalities include Bracebridge, Burk's Falls, Huntsville, Magnetawan, Parry Sound and Sundridge. For other municipalities, LPDL regularly reviews plans or permit applications and engages as needed. For each project, LPDL typically joins initial meetings, progress updates, and final discussions.

5.2.2.3.3 *Description*

For the majority of projects, LPDL applies for Roadway Occupancy Permits which typically include the proposed infrastructure design. This process keeps municipalities informed of our plans and provides them with the opportunity to identify potential conflicts with our design proposals. By coordinating with municipalities early in the project planning stages, we can address any concerns they might have and adjust our plans accordingly to minimize disruptions and optimize resource allocation.

Additionally, municipalities forward development proposals to LPDL for review and comment prior to issuing permits to developers. This collaborative approach ensures that new developments are aligned with our infrastructure plans and that any potential impacts on our services are considered and mitigated in advance. By working closely with municipalities, we can foster a cooperative relationship that benefits both parties and enhances the overall efficiency and effectiveness of our infrastructure projects.

Municipalities are a crucial resource in the process of ensuring developers are constructing to all relevant codes and specifications. Through the permitting process, LPDL identifies where developers may be proposing to install infrastructure that threatens the safety, maintainability or operability of our distribution system. For example, LPDL has a vested interest in ensuring that developers follow the Ontario Building Code ("**OBC**") with regard to clearance from high voltage conductors, as well as the Utility Distribution Standards. Furthermore, we are able to work with builders to ensure that objects like septic tanks, trees, etc. are not placed below our lines. The coordination results in an overall more mutually beneficial and respectful relationship.

Additionally, this cooperative relationship proves advantageous for developers, as they can receive comprehensive feedback from all relevant utilities before any permits are issued and construction begins. This pre-emptive consultation process helps to identify and address potential issues early on, thereby preventing costly delays and modifications during the construction phase. It also ensures that all infrastructure installations comply with safety standards and regulatory requirements, ultimately leading to a more efficient and harmonious development process. Through such diligent coordination, LPDL and the municipalities foster stronger, more collaborative partnerships that benefit all parties involved, including the community at large.

5.2.2.3.4 *Consultation Materials*

The outcomes of these consultations are in the form of construction information such as plans and associated schedules and budgets.

5.2.2.3.5 *Consultation Outcomes and Impact on this DSP*

Consultation with the Municipality in Parry Sound has provided substantial support for the Isabella Street Reconductor project. This collaboration has been particularly instrumental in ensuring the successful planning and execution of the project. One notable aspect of this consultation has been the alignment with the Town's plans to construct a new Recreational Centre, which will include the installation of EV chargers. By coordinating efforts with the Municipality, we have been able to synchronize our infrastructural developments with the Town's initiatives, thereby enhancing the overall efficiency and effectiveness of the project, reducing redundancy, and fostering a cooperative relationship that benefits the community at large. This integrated approach not only optimizes resource utilization but also ensures that both current and future infrastructure needs are met in a sustainable and forward-thinking manner.

5.2.2.4 Transmitter & Other LDC's

5.2.2.4.1 *Purpose of the Consultation*

LPDL is partially embedded within HONI service area and is fed from several 44 kV feeders supplied by HONI from Muskoka TS, Bracebridge TS and Parry Sound TS. LPDL often communicates and meets with HONI with the primary objective of providing reliable and cost-effective service to LPDL's customers. All past and future Distributed Generation ("**DG**") connections require co-ordination between HONI, LPDL and the generator to ensure safe and reliable connection to the grid. LPDL shares embedded generation facility Cost Connection agreements with HONI.

5.2.2.4.2 *Initiation and Participation*

Consultations may be initialed by either LPDL or HONI depending on needs and ownership.

5.2.2.4.3 *Description*

In 2021, LPDL and HONI initiated a significant project to enhance the reliability of power supply for LPDL customers. We transferred the load of two substations, Taylor DS and Bracebridge MS3, from the existing Muskoka TS M3 feeder to the new Bracebridge TS M21 feeder. This strategic move was facilitated by the proximity of Bracebridge TS, which is located less than 2km from both substations. As a result, this transfer not only improves the reliability and reduces outage durations for the connected areas but also lays the groundwork for future expansions and enhancements in the region's power infrastructure.

LPDL has coordinated with HONI for the installation and servicing of new 44kV motorized load-break switches. These switches provide HONI with significantly increased flexibility to transfer load remotely from the Ontario Grid Control Centre ("**OGCC**"). This enhancement not only improves operational efficiency but also helps in promptly addressing any disruptions in the power supply, thereby minimizing downtime and improving service reliability for customers. Additionally, the strategic placement of these switches ensures that the infrastructure can adapt to future expansions and modifications, supporting the long-term goals of both LPDL and HONI.

As part of normal business operations, LPDL and HONI coordinate regularly on various activities such as the replacement of poles, the transfer of wires, and the connection of new customers. Additionally, we collaborate on larger projects where HONI's planning or engineering expertise is required, such as the implementation of new Distributed Energy Resources ("**DER**") projects. This ongoing coordination ensures that all infrastructural developments are seamlessly integrated and that the overall reliability and efficiency of the service provided to customers are maintained at optimum levels.

5.2.2.4.4 *Consultation Materials*

Consultation materials may include regional planning documentation, design drawings, reliability and performance statistics, technical feasibility studies, and environmental impact assessments. These materials ensure that all stakeholders have a comprehensive understanding of the project's scope, potential challenges, and strategic benefits. Detailed reports and regular updates provide transparency and facilitate informed decision-making, while technical specifications and schematics guide the implementation processes. By incorporating a wide array of documents and data, the consultation process is thorough, collaborative, and geared towards achieving optimal outcomes for both LPDL and HONI.

5.2.2.4.5 *Consultation Outcomes and Impact on this DSP*

LPDL has undertaken two proposed projects that have emerged from extensive consultation and coordination with HONI. One notable initiative is the development of a joint pole line that spans the Muskoka River. This collaboration aims to create redundancy on both the LPDL-owned 27.6kV system and the two 44kV HONI-owned feeders. This project not only enhances the reliability of the power supply but also ensures a more robust infrastructure capable of handling future demands and potential contingencies.

One of the key justifications for installing a new 27.6kV substation at Bracebridge MS3 is to ensure that we have a substation serviced from an alternative Transformer Station (TS). This strategic move is expected to significantly reduce outage durations caused by loss of supply. Currently, the three existing 27.6kV substations are all serviced from the Muskoka TS M7, which has a history of poor performance. By diversifying the sources of supply, we aim to enhance the reliability and resilience of the power infrastructure, providing more consistent and dependable service to our customers.

5.2.2.5 Other LDCs & IESO

5.2.2.5.1 *Grid Innovation Fund*

LPDL initiated consultation with the Independent Electricity System Operator (IESO) to discuss the Grid Innovation Fund. During discussions, no good fit was found for LPDL. There was no application made, and this consultation has no impact on the DSP.

LPDL engaged in extensive discussions with the IESO regarding the Grid Innovation Fund. These discussions aimed to explore potential collaborations and funding opportunities that could align with LPDL's strategic goals and enhance the overall electricity infrastructure. However, after thorough evaluation, it was determined that none of the available options within the Grid Innovation Fund aligned perfectly with LPDL's current initiatives or long-term plans. As a result, no application was submitted for this particular funding cycle.

Despite this, the insights gained from these discussions were invaluable. The exchange of ideas helped LPDL to better understand the evolving landscape of grid innovation and potential future opportunities. This consultation, while not directly impacting the current DSP, has provided a foundation for future engagements and collaborations with IESO and other stakeholders. It ensures that LPDL remains well-informed and prepared to leverage similar opportunities as they arise, ultimately contributing to the resilience and reliability of the power infrastructure.

5.2.2.5.2 *Long-Term 2 (LT2)*

The IESO initiated meetings, and LPDL attended. The intent was to investigate the new procurement process and timelines from the IESO for new Generation and Demand Response. Consultation materials included the IESO LT2 documents online and LT2 information sessions. The LT2 consultations have no impact on this DSP.

The IESO initiated meetings, and LPDL attended these sessions with the goal of investigating the new procurement processes and timelines from the IESO for new Generation and Demand Response initiatives. Consultation materials included the IESO LT2 documents available online, as well as detailed LT2 information sessions that provided valuable insights. The LT2 consultations do not have a direct impact on the current DSP.

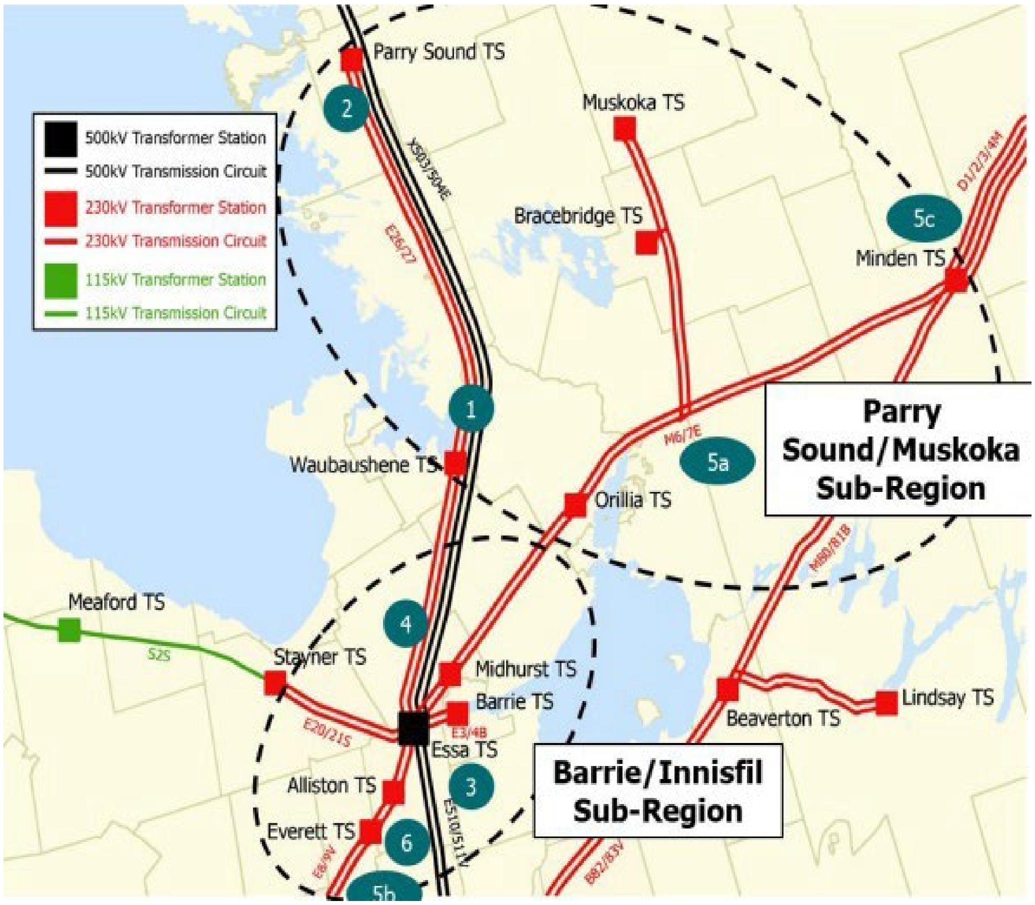
5.2.2.6 Regional Planning Process

The Regional Planning Process 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, HONI conducts a Needs Assessment ("**NA**") and develops a Regional Infrastructure Plan ("**RIP**") that involves representatives from the IESO, and LDCs of the planning region.

Figure 5.2-11: South Georgian Bay/Muskoka region

The South Georgian Bay/Muskoka planning region is further divided into two sub-regions - Parry Sound/Muskoka Sub-region and the Barrie/Innisfil Sub-region (depicted in Figure 5.2-12). LPDL is embedded within the Parry Sound/Muskoka Sub-region.

Figure 5.2-12: Parry Sound/Muskoka Sub-Region



LPDL is part of the South Georgian Bay/Muskoka planning region, shown in Figure 5.2-11. The planning region includes the following participants involved in the scoping assessment and regional planning for the South Georgian Bay/Muskoka region:

- Independent Electricity System Operator
- Alectra Utilities Corporation
- Hydro One Networks Inc. (Distribution)
- Hydro One Networks Inc. (Transmission)
- InnPower
- Orangeville Hydro
- Lakeland Power Distribution Ltd.
- EPCOR Electricity Distribution Ontario Inc.
- Newmarket-Tay Power Distribution Ltd.
- Wasaga Distribution Inc.

The initial regional planning cycle for the area concluded in December 2016 with the publication of the Integrated Regional Resource Plan ("**IRRP**"). This report highlighted that the Parry Sound TS had already surpassed the capacity of its transformers. Additionally, the report evaluated alternative capacity options, including the utilization of the Muskoka TS.

The subsequent cycle of regional planning commenced in January 2020 with a Needs Assessment (NA), adhering to the mandate that regional planning cycles be reviewed at a minimum every five years. The NA report for the South Georgian Bay/Muskoka region was published by HONI in April 2020, identifying several initiatives necessitating regional coordination. The findings from the NA were subsequently incorporated into the Scoping Assessment to define the specific planning process required. Released by the IESO in November 2020, the Scoping Assessment highlighted the need for additional coordination at the sub-regional level to formulate an IRRP for each of the two sub-regions. The IRRP for the Parry Sound/Muskoka sub-region was published in December 2022.

The proposed investments included in the 2025-2029 DSP align with the IRRP, and are not considered to have a major impact on LPDL's capital expenditures.

5.2.2.6.1 *NEEDS ASSESSMENT*

An NA was carried out by HONI for the South Georgian Bay/Muskoka region from January to April 2020. The purpose of the NA was to identify any new needs for the region as well as recommend a path forward for each need by either developing a preferred plan or identifying which needs require further assessment and/or regional coordination. Inputs considered for the NA included:

- Load forecast for all supply stations.
- Known capacity and reliability needs, operating issues and/or major assets approaching the End- of-Life ("**EOL**").
- Planned/foreseen transmission and distribution investments that are relevant to regional planning for the region.

HONI identified Parry Sound TS as in need of upgrade to meet forecast demands. Below is taken from the RPP published in 2022:

"Replace existing 230/44kV 42MVA transformers (T1/T2) with new 230/44kV 83MVA units and replace station protection and station service equipment. Replacement of these power transformers will help to maintain the reliability of supply and provide increased supply capacity to customers in the area by right sizing to 83MVA units."

5.2.2.7 TELECOMMUNICATION ENTITIES

LPDL has been coordinating particularly closely with Bell since 2020, starting with the Fiber-to-the-home ("**FTTH**") project in Parry Sound. This collaboration involves regular site meetings, extensive email correspondence, frequent phone calls, and thorough review and approval of design plans. The partnership ensures that infrastructure developments are synchronized efficiently, minimizing costs and disruptions for residents while enhancing overall service delivery.

Coordination with telecommunication entities is simply a normal part of effective day-to-day operations. The importance of coordinating with telecommunication entities cannot be overstated. This collaboration ensures that any infrastructure upgrades or replacements are efficiently aligned with telecommunications projects, such as the installation of new underground fiber networks. These FTTH projects fall under the New Connections capital project within the System Access category. By synchronizing these efforts, significant cost savings can be achieved through shared resources for trenching, road crossings, and remediation work. Moreover, it minimizes disruptions to residents, thereby enhancing overall customer satisfaction and operational efficiency.

Through consultation we identify areas of concern and coordinate capital expenditures between various entities. With the Universal Broadband Fund (UBF) and AHSIP (Accelerated High-Speed Internet Program) initiatives, it is instrumental that LDCs and telecommunication entities coordinate to ensure the existing infrastructure can support upgraded telecom infrastructure. Many areas that are being built lie in rural communities with aging utility infrastructure that need replacement or refurbishment to satisfy our obligations under Ontario Regulation 22/04.

Currently, no AHSIP applications have been made in LPDL's service territory. Consequently, this DSP is not impacted by the ongoing consultations with telecommunication entities. However, LPDL remains vigilant and recognizes that future AHSIP applications within the forecast period may necessitate adjustments to our capital expenditures. As such, we are committed to ongoing monitoring and coordination with telecommunication entities to ensure any required modifications can be promptly and effectively addressed.

Table 5.2-4: Telecommunications Consultation

Telecommunications Company	Participants	Consultation Frequency
Bell	Engineering Technician, LPDL; Engineering Supervisor, LPDL; Sr. OSP Engineering Team Lead, Vistacare Engineering (Bell Consultant); Specialist Network Provisioning, Bell	As required per project (weekly or bi-weekly)
Lakeland Networks	Engineering Technician, LPDL; Engineering Supervisor, LPDL; Outdoor Operations Manager, Lakeland Networks Manager of Planning, Lakeland Networks	As required per project (weekly or bi-weekly)

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

• The number of consultations that were conducted and a summary of the manner in which the distributor determined with whom to consult.

• A summary of the results of the consultations.

A statement as to whether the results of the consultations are reflected in the capital plan and, if so, a summary as to how.

5.2.2.8 CDM Engagements

LPDL has not had any utility-specific CDM-related consultations that have an impact on this DSP. LPDL is aware of and closely following activity relating to the letter sent from the Minister of Energy to the IESO on February 9, 2024 regarding Conservation and Demand Management Programs. Information to date indicates that the LDC marketing or delivery of CDM programs will be fully funded, and as such does not impact this DSP.

5.2.2.9 Renewable Energy Generation (REG)

A distributor is expected to coordinate with the IESO in relation to REG investments and confirm if there are REG investments in the region.

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

LPDL does not anticipate any REG investment over the forecast period.

5.2.3 Performance Measurement for Continuous Improvement

5.2.3.1 Distribution System Plan

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

In order to continually improve its operating performance, LPDL continually measures and monitors its performance. The performance measures tracked by LPDL align with the 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
- 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 LPDL's performance results over time and helps to benchmark its performance and improvement against other utilities and best practices. Table 5.2-6 summarizes LPDL's performance during historical years from 2019 to 2023.

In the last DSP, Performance measures were as follows:

Table 5.2-5: Performance Measures from the last DSP

Measure	Indicator	Motivation	Metrics
Customer oriented performance	Reliability	Consumer/ Regulatory	SAIFI SAIDI CAIDI Customer outages by cause code
	Customer satisfaction	Consumer /Regulatory	Customer survey results
	Consumer Bill Impacts	Consumer /Regulatory	Percentage Bill increase by customer class
	Power Quality	Consumer /Regulatory	Number of power quality complaints
	Service Quality	Consumer/ Regulatory	Telephone accessibility Telephone abandon rate Low voltage connections High voltage connections Appointments scheduling Appointments met Missed appointment rescheduling Written response to enquiries Emergency response – rural Emergency response – urban Reconnection performance standards Billing accuracy
Cost efficiency & effectiveness	DSP implementation	Regulatory/ Corporate	Physical progress vs. plan Financial progress vs. plan Actual vs. planned cost of work completed
	Total cost	Consumer/ Corporate	Total cost per customer Total cost per km of line
	Efficiency assessment	Regulatory/ Consumer Corporate	PEG efficiency assessment
Asset & systems operations performance	Distribution losses	Corporate	Percentage line loss
	Power Factor	Corporate	Power Factor

Customer Oriented Performance:

The SAIDI, SAIFI and CAIDI results are discussed in Section 5.2.3.2.2, highlighting the impacts of Loss of Supply on measured targets.

Customer Survey Results were fairly consistent from 2019 to 2021 to 2023. See Appendix C for a detailed discussion of Customer Survey Results.

The number of power quality complaints is discussed in Table 5.2-20. The increase in complaints observed in the year 2022 is largely driven by Loss of Supply and Adverse Weather.

Customer Service stats between 2019 and 2023 are consistent or showing an improving trend, as shown in Table 5.2-6 and Table 5.2-7.

Cost Efficiency & Effectiveness:

Budget vs actual from last plan to now (progress vs plan) is discussed in Section 5.4.1.1.

Lakeland Power primarily serves rural areas, where unique land conditions, asset conditions, and post COVID-19 asset cost increases have contributed to a slight upward trend in 2023 in both “Total cost per customer” and “Total cost per kM of line, whereas the trend is pretty much stable for the 2019-2022 period. However, LPDL is actively implementing strategies to maintain these costs at an optimal level within the forecasted period of the Distribution System Plan (DSP). Please refer to Table 5.2-6 for more details.

Asset Systems & Operations Performance:

Percentage line loss statistics are discussed in Section 5.3.2.1.3 specifically Table 5.3-26 and Table 5.3-27. HONI Transmission losses continue to be a significant contribution to overall efficiency numbers. LPDL has several initiatives to address line losses, including converting 4kV lines to 27.6kV.

Power factor drops in some summer months, but remains above 90% in remaining summer months, and all winter months. Improvement can be tracked through the last several years of the historical period. LPDL continues to monitor and take effective actions to address power factor concerns. More discussion on power factor is available in Section 5.3.2.2.1.

The measures from the previous DSP have been re-aligned into the objectives outlined in Section 5.2.1.4 as shown in Table 5.2-6 below:

- Customer Focus
- Operational Effectiveness
- Public Policy Responsiveness
- Financial Performance

Table 5.2-6: DSP Performance Measures

Performance Outcomes	Performance Categories	Measures		2019	2020	2021	2022	2023	Trend	Target: Industry	Target: Distributor
Customer Focus Services are provided in a manner that responds to identified customer preferences.	Service Quality	New Residential/Small Business Services Connected on Time		100.00%	100.00%	100.00%	100.00%	100.00%	⇨	90.00%	
		Scheduled Appointments Met On Time		100.00%	100.00%	100.00%	100.00%	100.00%	⇨	90.00%	
		Telephone Calls Answered On Time		89.61%	89.90%	90.81%	90.21%	93.38%	⇧	65.00%	
	Customer Satisfaction	First Contact Resolution		99.97	99.97%	99.96%	99.96%	99.93			
		Billing Accuracy		99.94%	99.92%	99.92%	99.64%	99.92%	⇩	98.00%	
		Customer Satisfaction Survey Results		75.5	77%	77%	77%	75			
Operational Effectiveness Continuous improvement in productivity and cost performance is achieved; and distributors deliver on system reliability and quality objectives.	Safety	Level of Public Awareness		83.80%	82.40%	82.40%	82.60%	82.60%			
		Level of Compliance with Ontario Regulation 22/04 [1]		C	C	C	C	C	⇨		C
		Serious Electrical Incident Index	Number of General Public Incidents	0	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	Average Number of Hours that Power to a Customer is Interrupted [2]		1.29	5.79	2.62	3.84	1.30	⇩		1.81
		Average Number of Times that Power to a Customer is Interrupted [2]		0.66	1.40	1.48	1.30	0.66	⇩		0.85
	Asset Management	Distribution System Plan Implementation Progress		In Progress	In Progress	In Progress	In Progress	In Progress			
	Cost Control	Efficiency Assessment		2	2	2	2	2			
		Total Cost per Customer [3]		$730	$718	$715	$795	$893			
		Total Cost per Km of Line [3]		$28,074	$28,361	$27,856	$29,642	$33,833			
Public Policy Responsiveness Distributors deliver on obligations mandated by government (e.g., in legislation and in regulatory requirements imposed further to Ministerial directives to the Board).	Connection of Renewable Generation	New Micro-embedded Generation Facilities Connected On Time								90.00%	
Financial Performance Financial viability is maintained; and savings from operational effectiveness are sustainable.	Financial Ratios	Liquidity: Current Ratio (Current Assets/Current Liabilities)		1.69	1.58	0.92	1.31	0.72			
		Leverage: Total Debt (includes short-term and long-term debt) to Equity Ratio		1.18	1.24	1.14	1.15	1.33			
		Profitability: Regulatory Return on Equity	Deemed (included in rates)	8.98%	8.98%	8.98%	8.98%	8.98%			
			Achieved	11.51%	6.07%	12.06%	11.82%	11.02%			

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

Legend:
5-year trend: ⇧ up ⇩ down ⇨ flat
Current year: target met; target not met

A review of LPDL's historical performance above indicates that LPDL has largely met or exceeded expectations over the historical period.

However, LPDL did not meet its SAIDI and SAIFI targets from 2020-2022 due to an increase in adverse weather and foreign interference.

5.2.3.2 Service Quality and Reliability

Chapter 7 of the OEB's Distribution System Code outlines the OEB's expectations regarding Service Quality Requirements (SQR) for Electricity Distributors. A distributor is required to provide the reported SQRs for the last five historical years. A distributor should also provide explanations for material changes in service quality and reliability, and whether and how the DSP addresses these issues. The OEB expects any five-year declining trends in reliability for SAIDI and SAIFI to be explained. If a distributor has reliability targets established in a previously filed DSP, as described below, any under-performance should also be explained.
A completed Appendix 2-G, documenting both the Service Quality and Service Reliability indicators, must be filed. A distributor must confirm that data is consistent with the scorecard or must explain any inconsistencies.
A summary of performance for the historical period using the methods and measures (metrics/targets) identified and described above, and how this performance has trended over the period, should be included. This summary must include historical period data on10:
• All interruptions
• All interruptions excluding loss of supply
• All interruptions excluding Major Events and loss of supply for the following:
o The distribution system average interruption frequency index (SAIFI)
o System average interruption duration index (SAIDI)11
The applicant should also provide a summary of Major Events that occurred since the last Cost of Service (CoS) filing.
For each cause of interruption, a distributor should, for the last five historical years, report the following data:
• Number of interruptions that occurred as a result of the cause of interruption
• Number of customer interruptions that occurred as a result of the cause of interruption
• Number of customer-hours of interruptions that occurred as a result of the cause of interruption

LPDL'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. Table 5.2-6 above shows the DSP Performance Measures from the OEB scorecard for 2023 – showing 2019 through 2023 results. , which is consistent with Appendix 2-G.

5.2.3.2.1 *Service Quality Requirements*

LPDL evaluates and tracks service quality based on its key principle of responsiveness to customer needs, ensuring continuous improvement and high customer satisfaction. LPDL monitors and reports on Service Quality Requirements ("**SQR**") in line with Chapter 7 of the OEB's DSC. Table 5.2-7 displays LPDL's SQR performance for the historical period.

Table 5.2-7: Historical Service Quality Metrics

Service Quality Metric	2019	2020	2021	2022	2023	Minimum Standards
Low Voltage Connections	100.00%	100.00%	100.00%	100.00%	100.00%	> 90%
High Voltage Connections						> 90%
Telephone Accessibility	89.61%	89.90%	90.81%	90.21%	93.38%	> 65%
Appointments Met	100.00%	100.00%	100.00%	100.00%	100.00%	> 90%
Written Response to Enquires	96.43%	93.75%	93.33%	100.00%	100.00%	> 80%
Emergency Urban Response	100.00%	100.00%	100.00%	100.00%	92.31%	> 80%
Emergency Rural Response	100.00%	100.00%	100.00%	100.00%	100.00%	> 80%
Telephone Call Abandon Rate	1.05%	1.08%	1.12%	1.29%	1.14%	< 10%
Appointment Scheduling	80.99%	85.80%	70.65%	67.06%	90.65%	> 90%
Rescheduling a Missed Appointment						> 100%
Reconnection Performance Standard	100.00%	100.00%	100.00%	100.00%	100.00%	> 85%
New Micro-embedded Generation Facilities	-	-	-	-	-	> 90%
Bill Accuracy	99.94%	99.92%	99.92%	99.64%	99.92%	> 98%

A comprehensive review of the service quality indicators data reveals that LPDL has consistently exceeded the SQR expectations over the historical period, with the exception of Appointment Scheduling. From 2019-2022, the industry-wide demand for on-time underground locates posed a significant challenge, particularly during a period of economic growth.

Throughout 2022-2023, LPDL's underground locate provider, G-Tel, undertook a substantial hiring initiative and increased compensation, leading to a marked improvement in locate compliance. Consequently, the cost of locates has increased significantly.

The improvements seen in 2023 highlight LPDL's commitment to excellence and responsiveness to customer needs.

<u>Billing Accuracy:</u>

On matters of billing and payment, LPDL continues to score in the 80th percentile for customer satisfaction in billing accuracy.

Table 5.2-8: Customer satisfaction - Billing accuracy

Satisfaction with the ACCURACY of your bills				
		LPDL	Residential	GS<50kW
NET satisfied	2023	82%	81%	86%
	2021	89%	89%	86%
	2019	81%	81%	81%
NET dissatisfied	2023	1%	1%	0%
	2021	2%	2%	2%
	2019	2%	2%	2%

Pricing:

LPDL customers feel they are receiving value for money, with an upward trend from 2019 to 2023 in customer satisfaction on the percentage of the bill kept by LPDL for services provided.

Table 5.2-9: Customer Satisfaction - Pricing

Do you feel that the percentage of your (household/organizations)'s total electricity bill that you pay to Lakeland Power for the services they provide is...?				
		LPDL	Residential	GS<50kW
NET satisfied	2023	56%	58%	45%
	2021	42%	42%	47%
	2019	46%	46%	44%
NET dissatisfied	2023	12%	13%	7%
	2021	10%	10%	5%
	2019	12%	12%	4%

Reliability:

The 2019, 2021, and 2023 Customer Satisfaction Surveys show a downward trend in customer satisfaction with regards to Reliability.

Table 5.2-10: Customer Satisfaction - Reliability

Satisfaction with the RELIABILITY of your electricity service as judged by the number of power outages you experience.		LPDL	Residential	GS<50kW
Base: total answering		400	360	40
NET satisfied	**2023**	74%	75%	65%
	2021	74%	74%	73%
	2019	80%	81%	79%
NET dissatisfied	**2023**	18%	18%	10%
	2021	19%	20%	14%
	2019	11%	11%	6%

Satisfaction with the amount of TIME IT TAKES TO RESTORE POWER when power outages occur.		LPDL	Residential	GS<50kW
Base: total answering		400	360	40
NET satisfied	**2023**	71%	72%	61%
	2021	77%	77%	74%
	2019	79%	79%	83%
NET dissatisfied	**2023**	15%	14%	21%
	2021	13%	13%	17%
	2019	10%	11%	2%

Satisfaction with the QUALITY OF THE POWER delivered to you as judged by the absence of voltage fluctuations that can result in flickering/dimming of lights/ an affect on equipment.		LPDL	Residential	GS<50kW
Base: total answering		400	360	40
NET satisfied	**2023**	82%	82%	79%
	2021	85%	85%	88%
	2019	84%	85%	82%
NET dissatisfied	**2023**	7%	7%	5%
	2021	5%	5%	5%
	2019	7%	6%	8%

5.2.3.2.2 *Reliability Requirements*

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

1. By including all power interruptions.
2. By excluding interruptions due to Loss of Supply ("**LOS**").

3. By excluding interruptions due to LOS and Major Event Days (“**MED**”).

Historically, LPDL’s main cause of outages has been Loss of Supply from Hydro One.

Table 5.2-11: Historical Reliability Performance Metrics – All Cause Codes

Metric	2019	2020	2021	2022	2023	Average
SAIDI	7.66	11.39	8.99	13.35	2.34	8.75
SAIFI	3.71	4.81	4.16	4.65	1.04	3.67
CAIDI	2.06	2.37	2.16	2.07	2.25	2.18

Table 5.2-12: Historical Reliability Performance Metrics: LOS and MED Adjusted

	Loss of Supply Adjusted (including MEDs, Excluding LOS)					
Metric	**2019**	**2020**	**2021**	**2022**	**2023**	**Average**
SAIDI	1.29	5.78	2.62	4.24	1.30	3.05
SAIFI	0.66	1.40	1.48	1.30	0.66	1.10
CAIDI	1.95	4.13	1.77	3.26	1.97	2.62
	Major Event Days Adjusted (including LOS, Excluding MEDs)					
Metric	**2019**	**2020**	**2021**	**2022**	**2023**	**Average**
SAIDI	7.67	10.42	7.00	6.18	2.34	6.72
SAIFI	3.72	4.35	3.93	3.23	1.04	3.25
CAIDI	2.06	2.40	1.78	1.91	2.25	2.08
	Loss of Supply and Major Event Days Adjusted (Excluding LOS and MEDs)					
Metric	**2019**	**2020**	**2021**	**2022**	**2023**	**Average**
SAIDI	1.29	5.79	2.62	3.84	1.30	2.97
SAIFI	0.66	1.40	1.48	1.30	0.66	1.10
CAIDI	1.95	4.14	1.77	2.95	1.97	2.56

Figure 5.2-13: Historic Performance Measure - SAIDI

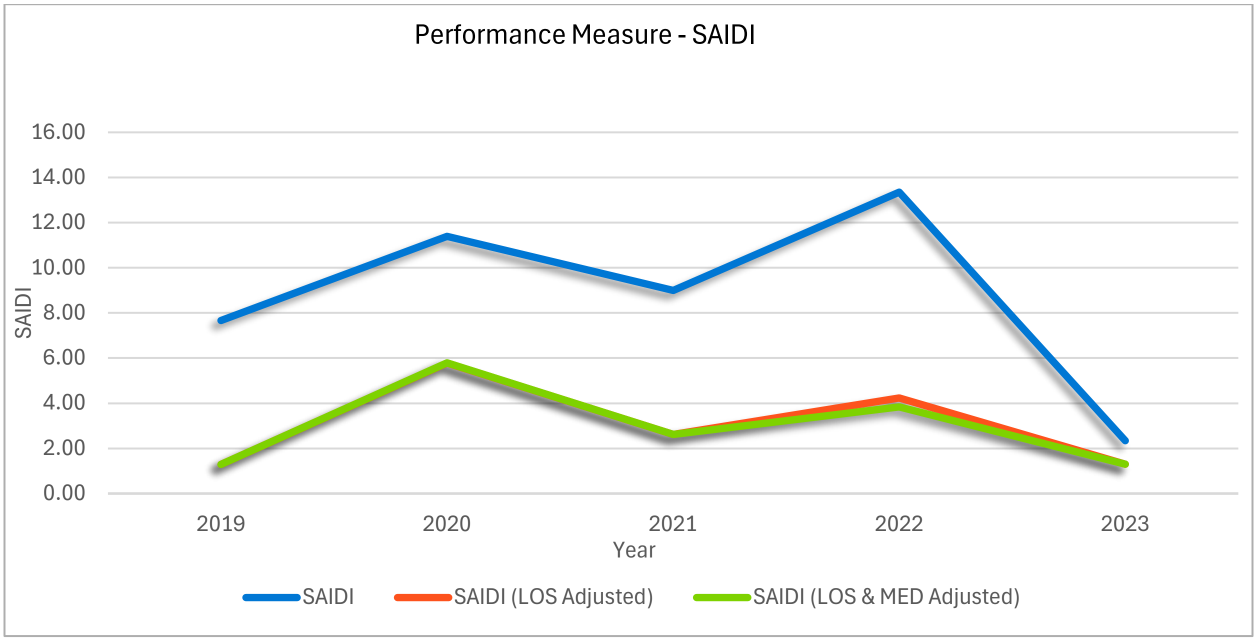


Figure 5.2-14: Historic Performance Measure - SAIFI

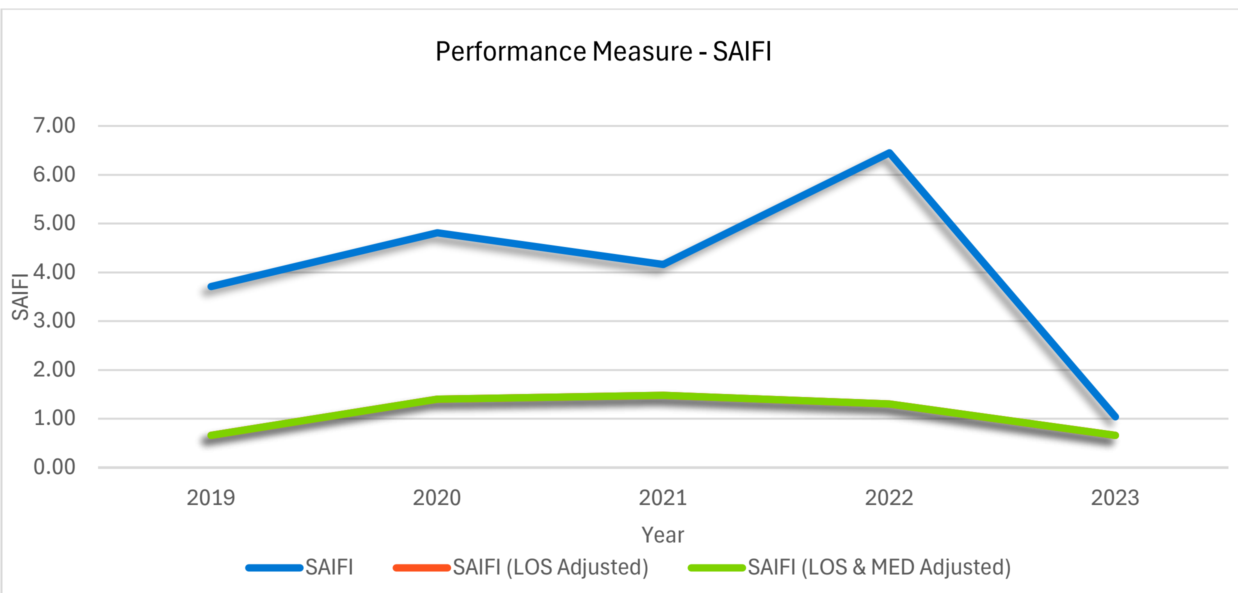
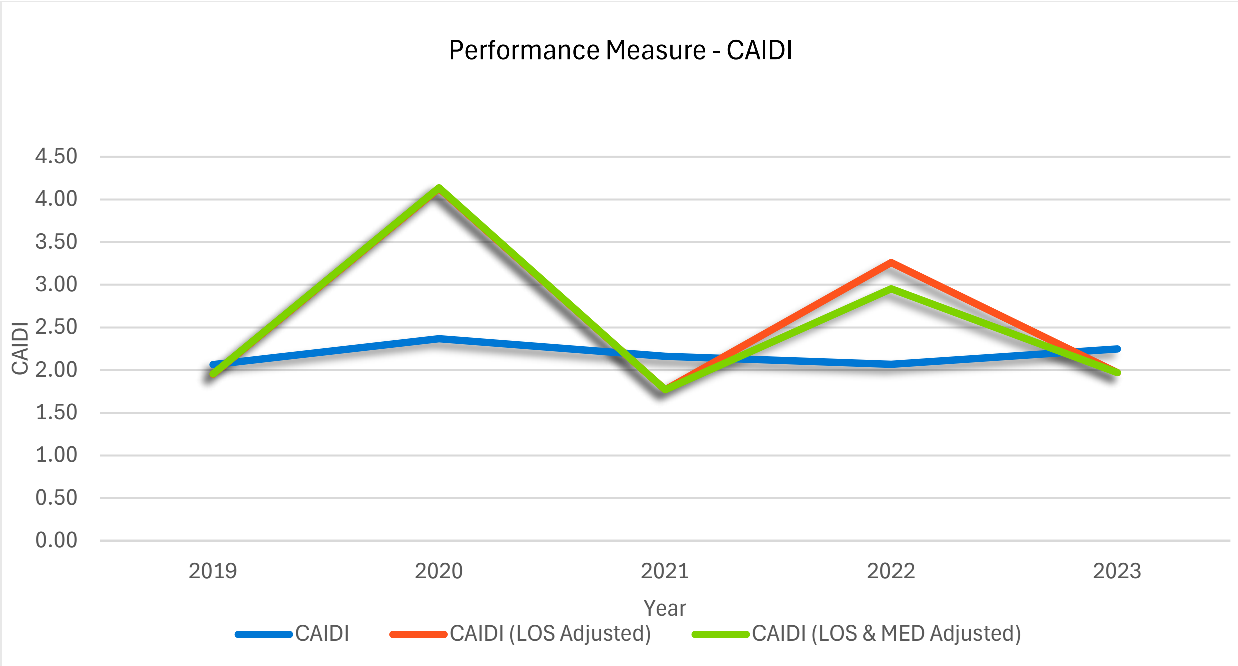


Figure 5.2-15: Historic Performance Measure - CAIDI



Unadjusted SAIDI and SAIFI numbers show declining trends due to events outside of LPDL's control, specifically Loss of Supply from HONI and major weather events. The five-year trends when adjusted for LOS and MED are flat.

5.2.3.2.3 *Outage Details for Years 2019-2023*

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

Table 5.2-13: Summary of MEDs over the Historical Period

Year	# of MEDS	Cause of MEDS
2019	0	N/A
2020	2	Adverse Weather - Wind
2021	1	Adverse Weather - Wind
2022	1	Adverse Weather - Wind
2023	0	N/A

Table 5.2-14: List of MEDs over Historical Period

Date	Customer Base Interrupted	Description
June 10th, 2020	922	On June 10, 2020, Bracebridge experienced a tornado that saw the interruption of 922 customers, with 20,937 hours interrupted.
October 23rd,2020	7,965	On October 23rd, 2020, due to a severe storm, LPDL claimed a Major Event. This storm with high winds caused 7,965 customers to be affected, and a total of 26,586 customer hours interrupted.
September 22nd, 2021	3,415	On September 22, 2021, an MED occurred causing 3,415 customers to be affected and a total of 28,680 customer hours interrupted. This again was caused by a storm with high winds
October 22nd, 2022	10,902	On October 20th, 2022, 10,902 customers were affected and a total of 48,457 customer hours interrupted. This was due to a snowstorm during relatively warm weather. The heavy warm snow sticks to trees causing heavy sag and breakage.
December 24th, 2022	11,265	On December 24th, 2022, Adverse Weather caused 11,265 customers to be affected and a total of 39,016 customer hours interrupted. This was due to Loss of Supply

5.2.3.2.3.1 Outages by Cause Codes

Table 5.2-15 presents a summary of total outages that have occurred within LPDL's service territory providing three different categorizations. The table values indicate a slightly decreasing trend of outages within LPDL service territory. A further breakdown by cause codes is provided in the following subsections.

Table 5.2-15: Number of Outages (2019-2023)

Categorization	2019	2020	2021	2022	2023
All Interruptions	196	177	121	122	132
All Interruptions excluding LOS	172	155	101	105	119
All Interruptions excluding MEDS & LOS	172	152	97	101	119

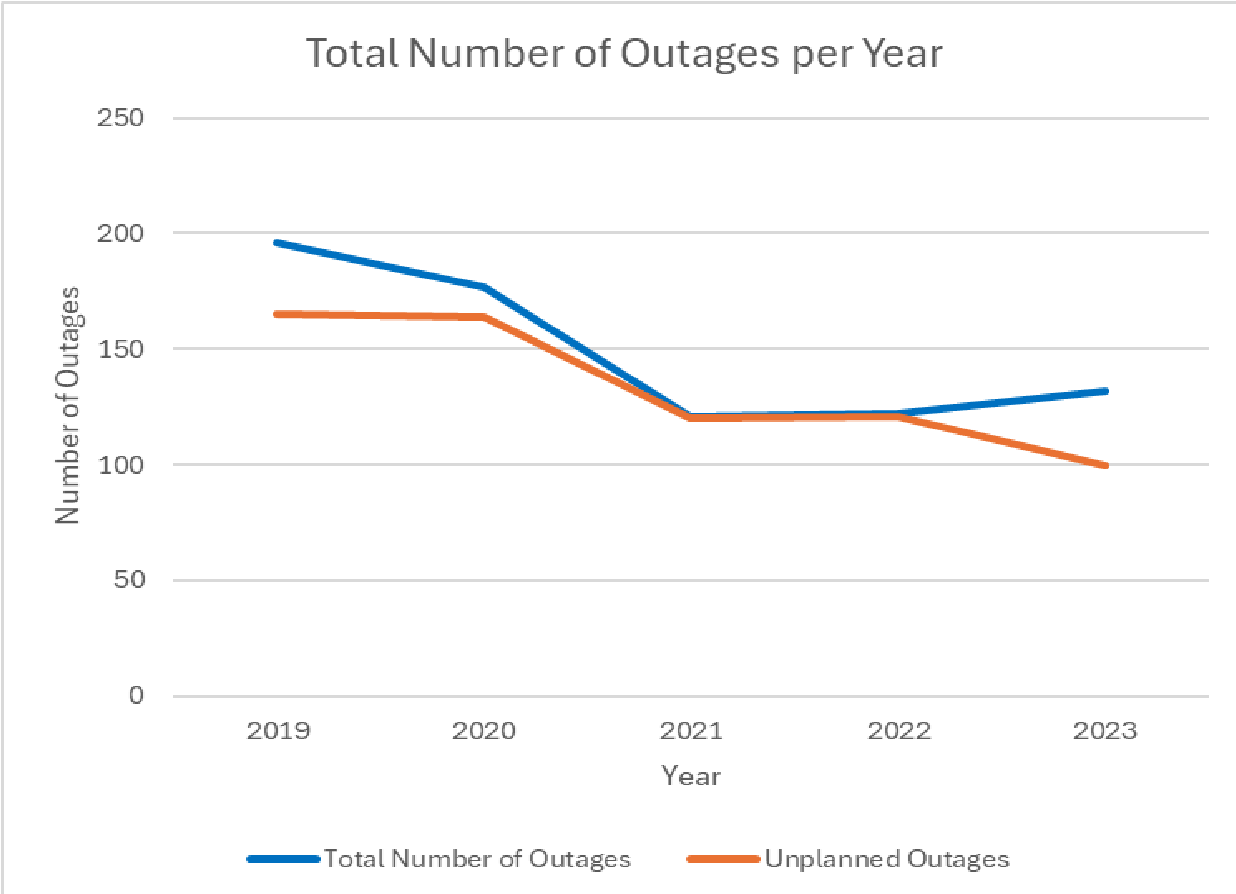
5.2.3.2.3.2 Outages Experienced

Table 5.2-16 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. Lakeland Power continues to assess and execute capital and O&M projects to manage the number of outages experienced.

Table 5.2-16: Outage Numbers by Cause Code – Excluding MEDs

Cause Code	2019	2020	2021	2022	2023	Total Outages	%
0-Unknown/Other	10	17	8	11	8	54	7.22%
1-Scheduled Outage	31	13	1	1	32	78	10.43%
2-Loss of Supply	24	22	20	17	10	93	12.43%
3-Tree Contacts	20	14	16	16	22	88	11.76%
4-Lightning	1	2	3	0	3	9	1.20%
5-Defective Equipment	55	46	28	30	20	179	23.93%
6-Adverse Weather	15	16	15	19	13	78	10.43%
7-Adverse Environment	0	0	0	0	0	0	0.00%
8-Human Element	3	3	0	0	2	8	1.07%
9-Foreign Interference	37	44	30	28	22	161	21.52%
Total	**196**	**177**	**121**	**122**	**132**	**748**	**100.00%**

Figure 5.2-16: Total Number of Outages per Year over Historical Period

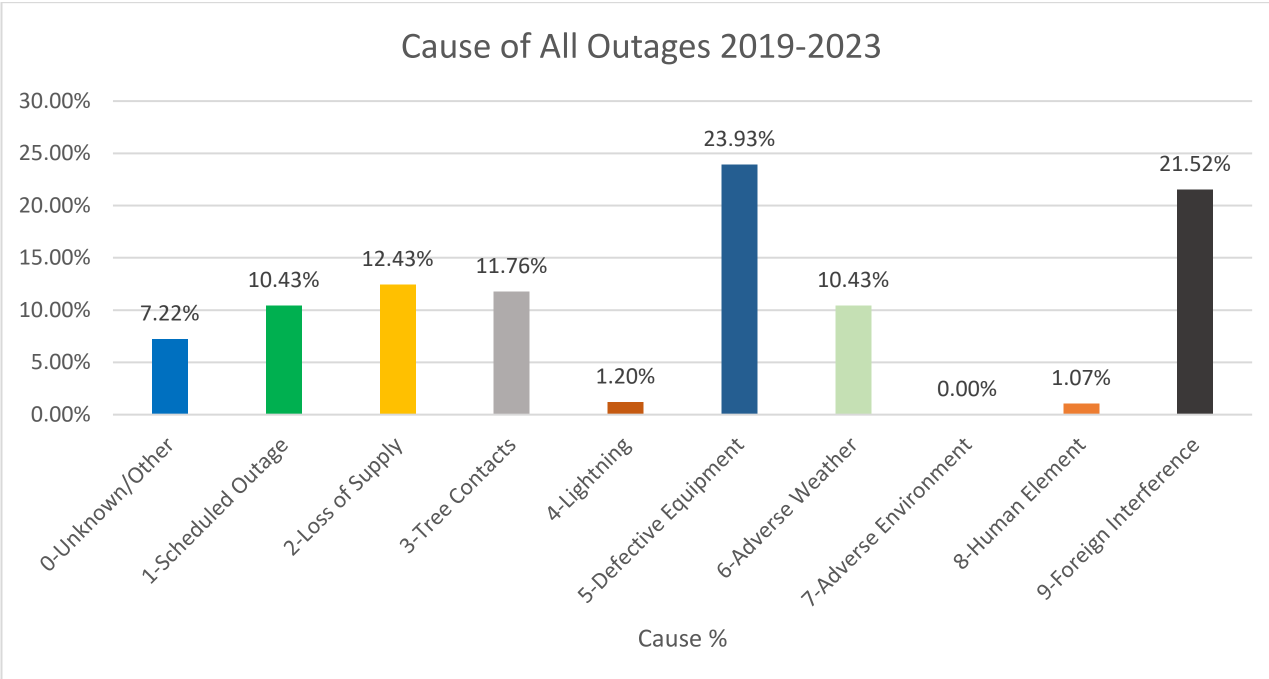


As shown in Table 5.2-16, the number of Defective Equipment outages has decreased year on year. This is a result of Lakeland Power taking the necessary steps to improve our distribution area and provide our customers with a more reliable service.

The total number of interruptions over the historical period is shown in Figure 5.2-16, varying from a low of 121 to a high of 196, with the overall trend decreasing in the period.

A summary of the causes of outages within Lakeland Power's system is presented in Table 5.2-17, along with the percentage of overall outage incidents attributable to each cause type.

Table 5.2-17: 2019-2023 Cause of All Outages



Defective Equipment, Foreign Interference, Loss of Supply, and Tree Contacts have been identified to be the four most common causes for outages on Lakeland Power's distribution system over the historical period. Together, these causes contributed 69% of the total number of outages from 2019 to 2023, excluding MEDs. Defective Equipment is the top contributing cause to the total outages experienced by Lakeland Power. Defective Equipment accounted for 23.9% of the total outages experienced by Lakeland Power over the historical period. These failures result from condition deterioration, ageing effects or imminent failures detected from reoccurring maintenance programs. Lakeland Power has planned investments to prioritize assets for replacement before experiencing a failure that may cause an outage.

At 21.5%, Foreign Interference is the second top contributing cause to the total outages experienced by Lakeland Power. The outages contributing to the cause include animal interference, dig-ins, vehicle collisions and/or foreign objects. Some of these contributing factors can be minimized such as educating the public about calling before digging or installing wildlife guards in areas observed to have a high activity of animals, both of which Lakeland Power 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 outage impact.

Loss of Supply outages is the third top contributing cause to the total outages experienced at 12.4%.

Tree Contacts was identified as the fourth top contributing cause to the total outages experienced by Lakeland Power. Over the historical period, this category has contributed to 11.7% of the total number of outages that occurred. Lakeland Power outsources tree trimming to a third-party entity.

5.2.3.2.3.3 Customers Interrupted and Customers Hours Interrupted

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

Table 5.2-18: Customers Interrupted Numbers by Cause Codes: Excluding MEDs

Cause Code	2019	2020	2021	2022	2023	Total CI	%
0-Unknown/Other	1,507	1,513	295	3,348	1,548	8,211	3.17%
1-Scheduled Outage	1,015	333	2	9	546	1,905	1%
2-Loss of Supply	42,095	55,005	37,936	48,239	5,493	188,768	72.82%
3-Tree Contacts	1,927	802	5,001	1,423	3,368	12,521	5%
4-Lightning	1	405	26	0	369	801	0.31%
5-Defective Equipment	720	964	2,153	1,119	270	5,226	2%
6-Adverse Weather	3,306	7,372	10,114	10,797	2,746	34,335	13.25%
7-Adverse Environment	0	0	0	0	0	0	0%
8-Human Element	169	533	0	0	181	883	0.34%
9-Foreign Interference	469	215	3,408	1,948	537	6,577	3%
Total	**51,209**	**67,142**	**58,935**	**66,883**	**15,058**	**259,227**	100%

Figure 5.2-17: Total Number of Customers Interrupted by Year over Historical Period

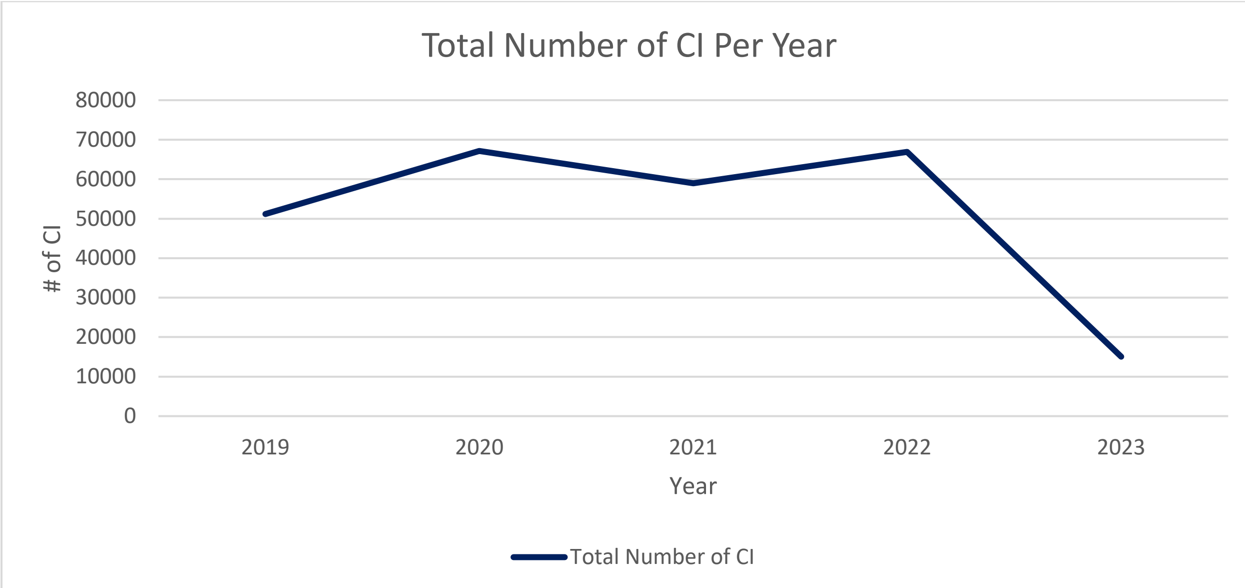
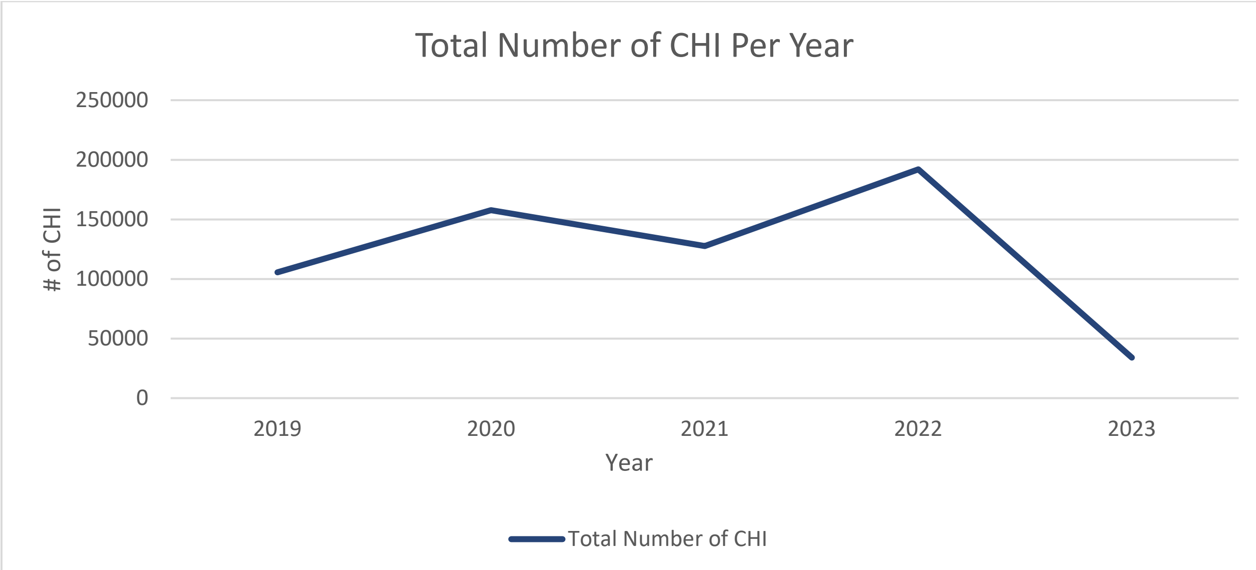


Table 5.2-19: Customer Hours Interrupted Numbers by Cause Code – Excluding MEDs

Cause Code	2019	2020	2021	2022	2023	Total CHI	%
0-Unknown/Other	1,882	2,055	499	2,208	1,419	8,063	1.31%
1-Scheduled Outage	3,571	739	2	4	961	5,277	1%
2-Loss of Supply	87,915	100,038	90,395	131,151	15,160	424,659	68.82%
3-Tree Contacts	3,205	2,374	6,914	2,583	7,911	22,987	4%
4-Lightning	3	1,044	56	0	1,683	2,786	0.45%
5-Defective Equipment	2,105	1,402	3,863	3,076	799	11,245	2%
6-Adverse Weather	6,046	49,073	16,703	44,876	4,850	121,548	19.70%
7-Adverse Environment	0	0	0	0	0	0	0%
8-Human Element	143	798	0	0	121	1,062	0.17%
9-Foreign Interference	819	309	9,143	8,072	1,109	19,452	3%
Total	**105,689**	**157,832**	**127,575**	**191,970**	**34,013**	**617,079**	100%

Figure 5.2-18: Total Number of Customers Hours Interrupted by Year over Historical Period



The trend for total number of CI over the historical period is relatively stable with some increase in 2022 but a large improvement in 2023 and the trend for total number of CHI over the historical period is stable with a large improvement in 2023. The increase in CI observed in the year 2022 is largely driven by Loss of Supply and Adverse Weather, and the increases in CHI observed in 2022 can be largely attributed to Loss of Supply.

LPDL prioritizes issues/concerns that are reported. LPDL immediately addresses concerns such as partial power, flickering lights, and power surges. With Voltage concerns, usage issues requested by customers are usually investigated within 24 hours. Table 5.2-20 lists the power quality complaints over the historical period. There are 0 unresolved complaints.

Table 5.2-20: Historical Power Quality Issues (2019-2023)

Power Issues	2019	2020	2021	2022	2023
Blown Fuse	0	0	0	0	0
Brown Out	1	0	0	0	0
Flickering Lights	1	2	1	2	0
Fluctuation Power	1	0	0	1	0
Part Power	1	0	0	0	0
Power Surges	5	0	0	0	0
Voltage Issue	5	5	2	8	4
Total:	**14**	**7**	**3**	**11**	**4**

5.2.3.3 Distributor Specific Reliability Targets

As established in the Report of the OEB: Electricity Distribution System Reliability Measures and Expectations[12], distributors' SAIDI and SAIFI performance is expected to meet the *performance target set out in the Scorecard. Distributors who wish to establish performance expectations based on something other than historical performance should provide evidence of their capital and operational plan and other factors that justify the reliability performance they plan to deliver. Distributors should also provide a summary of any feedback from their customers regarding the reliability of the distributor's system. Distributors who wish to use SAIDI and SAIFI performance benchmarks that are different than the historical average must provide evidence to support the reasonableness of such benchmarks.*

LPDL relies on the SAIDI and SAIFI performance benchmarks that are established by the OEB and does not use distributor-specific reliability targets.

5.3 Asset Management Process

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

5.3.1 Planning Process

5.3.1.1 Overview

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

LPDL's Asset Management process proactively addresses risks in their electricity distribution system, enabling them to serve customers and communities with cost-effective, reliable, and safe electric power. This comprehensive process is guided by LPDL's internal mission, vision, values, strategic goals, and external regulatory obligations such as the OEB's RRF Performance Outcomes and requirements specified in the DSC and the OEB Act. By adhering to these principles, and ensuring regulatory compliance, LPDL ensures that every facet of their operations is aligned with their commitment to excellence and sustainability. LPDL's objectives, derived from this philosophy, guarantee that customers receive the expected service levels while maintaining financial accountability and making sustainable investments for future growth and innovation. The meticulous planning and execution of asset management strategies are pivotal in achieving long-term reliability and operational efficiency.

LPDL's AM objectives are:

- Public & Worker Safety

- System Reliability & Capacity
- Organizational Efficiency & Productivity
- Customer Preference
- Innovation
- Environmental Sustainability

In addition to the AM objectives, LPDL operates based on corporate values listed below and further detailed in Appendix E.

Safety: We are dedicated to the safety of our employees and communities.

Environmental Stewardship: We are concerned for the environment in everything we do. We are committed to protecting and nourishing the environment by doing better for our planet while we grow.

Reliability: We provide dependable, consistent, and reliable service.

Accountability: We are serious and responsible for our actions and accountable to those we serve.

Partnerships: We draw on one another and our partners to achieve success.

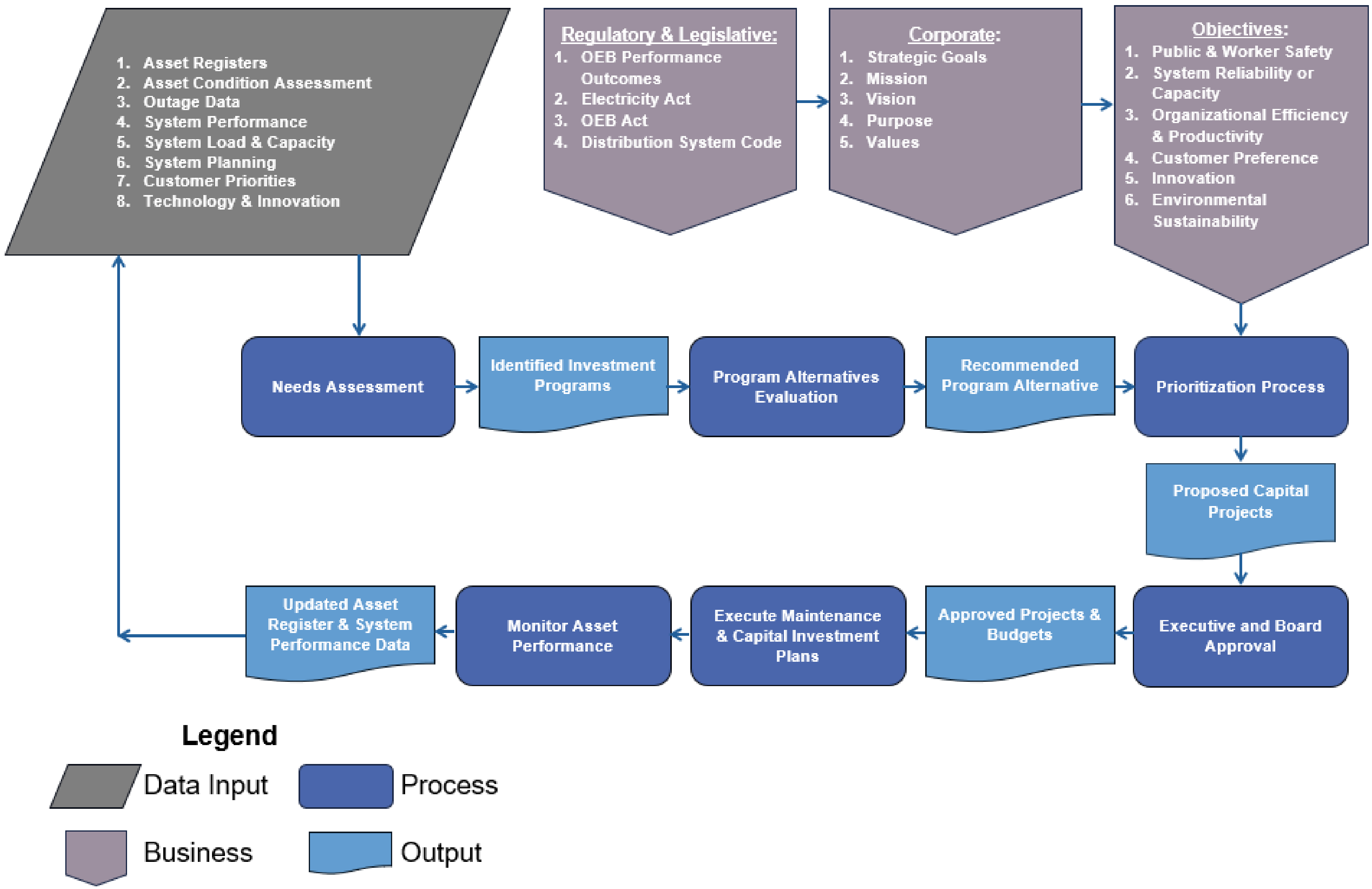
Professionalism: We are dedicated to excellence in management and service delivery. We are inclusive and are committed to providing equitable services and treating all with respect.

Continuous Improvement: We constantly seek new ideas, are future-focused and results-oriented. We are efficient, effective, innovative, and we offer value-added.

Relationship Building & Reconciliation: We are committed to relationship building and reconciliation. We are driven by trust and integrity and we value the knowledge and experience of all.

Figure 5.3-19 provides a visual summary of LPDL's Asset Management process. Detailed explanations of each step are covered in Section 5.3.1.3.

Figure 5.3-19: Asset Management Process Flow Chart



5.3.1.2 Important Changes to Asset Management Process since last DSP Filing

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

Since the last DSP filing, LPDL has implemented significant enhancements to its asset management process. Previously, LPDL's DSP lacked a condition-based asset assessment to aid in identifying the quantity and location of assets requiring replacement. Furthermore, there was no established project prioritization and weighting criteria to ensure that projects selected within fixed funding parameters were of the highest priority. These methodologies have now been developed and incorporated into the current DSP filing.

Key changes to LPDL's asset management process since the previous DSP include the creation of project prioritization and weighting mechanisms to rank and objectively prioritize upcoming discretionary projects. This system ensures that investments are consistently aligned with strategic goals and operational needs.

LPDL has also integrated it's ACA into it's GIS (utilizing ArcGIS Pro) with a detailed asset registry. This integration enables System Renewal projects to be informed by both testing and inspection data. LPDL has initiated the testing of assets, such as poles, to determine their condition rather than relying solely on age demographics. Wherever possible, LPDL utilizes ACA to assign a Risk Rating ("**RR**") score to assets. In addition, assets are rated based on their impact of failure and accessibility.

Using the GIS system, risk rating outputs from the ACA are spatially represented to visually identify areas with clusters of assets in poor or very poor condition. This spatial representation aids LPDL in identifying potential capital projects.

5.3.1.3 Process

A distributor should provide the processes used to identify, select, prioritize (including reprioritizing investments over the five-year term), optimize and pace the execution of investments over the term of the DSP. A distributor should be able to demonstrate that it has considered the correlation between its capital plan and customers' feedback and needs. A distributor should also demonstrate that it has considered the potential risks of proceeding/not proceeding with individual capital expenditures (e.g., the risk/benefit of a reactive service transformer replacement program instead of proactively replacing service transformers).
A distributor should demonstrate how it does grid optimization using an approach that considers the distributor's whole system. This should include, where applicable, assessing the use of non-wires alternatives, distributed energy resources, cost-effective implementation of distribution improvements affecting reliability and meeting customer needs at acceptable costs to customers, other innovative technologies, and consideration of distribution rate funded Conservation and Demand Management (CDM) activities.

A distributor must also demonstrate that it has a planning process for future capacity needs of the distribution system, which must include, among others, increased adoption of electric vehicles. On November 2, 2022, the OEB posted the "Load Forecast Guideline for Ontario" provided by the Regional Planning Process Advisory Group (RPPAG), which provided guidance in the development of demand forecasts to increase consistency among distributors.[14] *Distributors should consider this guidance when developing their load forecasts. The guidance recommended a sensitivity analysis to capture uncertainty in the demand forecast and noted "one of the evolving components with respect to the demand for electricity is electrification which is expected to change the growth patterns such as they are not well represented by historical trends."*[15]

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

LPDL's asset management process has seen significant improvements since its inception, with the benefits being increasingly evident. LPDL remains dedicated to the continuous enhancement of its ACA. Future improvements will include the addition of more assets to our formal ACA, such as station lightning arresters, ensuring compliance with all relevant codes and standards, and mindfully adjusting criteria to ensure the greatest results are generated. This ongoing commitment to refinement and expansion underscores LPDL's dedication to maintaining a robust and responsive asset management strategy. The detailed asset management process of LPDL is illustrated in Figure 5.3-19.

LPDL's AM process can be summarized in the following six steps:

1. Needs Assessment
2. Program Alternatives Evaluation
3. Prioritization Process
4. Executive and Board Approval
5. Execute Maintenance & Capital Investment Plans
6. Monitor Asset Performance

The six steps are elaborated in the following subsections.

5.3.1.3.1 NEEDS ASSESSMENT

LPDL considers asset registers, ACA results, regulatory requirements, outage data, system performance data, system & load capacity, system planning customer priorities, and technology & innovation as its primary inputs for a Needs Assessment (NA). In addition, an important aspect of LPDL's business efficiency is our compact and efficient team, each of which is familiar with the systems in each municipality.

NAs result will vary depending on the investment category and whether the project is discretionary. For example, new customer connections will always be given high priority.

System Access projects, especially new customer projects, are identified by external stakeholders throughout the year. These mandatory projects are planned to meet the timing needs of external supporters. LPDL must consider these high priority in order to meet business obligations.

System Renewal projects are optional and focus on upgrading old infrastructure. The needs for these projects are determined through the ACA by utilizing data such as asset inspections and reliability data.

System Service projects, also optional, address expected load changes that could affect the system's capacity to deliver consistent service. These projects may be guided by the regional planning process, however most often are identified by experienced engineering consultants that recognize a need through discussion with various parties, including customers.

General Plant projects, such as acquiring or replacing fleet vehicles and upgrading software/hardware, are also discretionary. These projects are identified internally by various departments and supported by inspection and maintenance activities, best practices, regulatory requirements, and manufacturer recommendations.

5.3.1.3.2 *PROGRAM ALTERNATIVES EVALUATION*

In almost all cases, considerations for alternatives must be considered before a project will be approved by the Executive team and the Board of Directors.

Alternatives vary greatly depending on the project. For example, when purchasing vehicles, we consider alternatives of downsizing our fleet to conserve costs. For system renewal projects, we consider whether maintenance can be performed to extend the life and/or reliability of assets. While completing long term planning, such as 4.16kV to 12.47kV conversions in Parry Sound, we strongly consider the consequences and the financial benefits vs. drawbacks of maintaining two separate systems.

The results of alternative evaluation depend greatly on staff experience, analysis of the cost and benefit, as well as the expected improvement to the system.

In nearly all scenarios, the evaluation of alternatives is a prerequisite before a project can obtain approval from the executive team and the board of directors.

Alternatives vary considerably depending on the project type. For instance, when assessing vehicle procurement, we evaluate alternative options such as fleet downsizing to optimize cost-efficiency. For system renewal projects, we assess whether maintenance strategies can be implemented to extend asset life and reliability. During long-term planning activities, such as the 4.16kV to 12.47kV system conversions in Parry Sound, we conduct rigorous evaluations of the operational impacts and financial implications of maintaining dual voltage systems.

The outcomes of the alternatives evaluation are heavily reliant on the expertise of staff, detailed cost-benefit analyses, and the anticipated enhancements to system performance.

5.3.1.3.3 *Prioritization Process*

Following the identification and evaluation of project alternatives, a prioritization process is initiated. Inputs such as LPDL's AM objectives, corporate goals, and OEB performance outcomes are considered alongside the identified programs to generate a prioritized project list. Not listed separately, regulatory and legal compliance is built into all of the prioritization factors.

Non-discretionary projects, primarily System Access, are prioritized based on external schedules and needs, occasionally requiring multi-year investments. These are evaluated using factors like growth rates, safety, reliability, performance, condition, and age.

Discretionary projects, including System Renewal, System Service, and General Plant, are prioritized based on value and risk assessments. Multi-year investments such as the Pole Replacement and Transformer Replacement Programs are included. Weights are assigned to AM objectives to enhance the objectivity of the process.

LPDL's Project Prioritization criteria are summarized in Table 5.3-21.

Table 5.3-21: LPDL Project Prioritization Criteria

LPDL Prioritization Criteria	
Objectives	**Weight Factor**
Public & Worker Safety	6
System Reliability or Capacity	5
Organizational Efficiency & Productivity	3
Customer Preference	3
Innovation	2
Environmental Sustainability	2

Each project is rated 0-4 for each prioritization criteria, for a maximum rating of 84. When rating projects, engineering staff take into consideration the risk, consequence, or degree of improvement on the criteria. For example, Cybersecurity was given a 4 for System Reliability, because Cybersecurity is an emerging concern for all technologically-driven companies, and LPDL's Board of Directors has indicated it as LPDL's greatest threat. Projects identified through our ACA are given 4 on System Reliability as they represent our most at-risk components in the system, however are generally given 0 for innovation unless there can be efficiencies realized that align with innovative projects.

5.3.1.3.4 *Executive and Board Approval*

Budgets and proposed capital expenditures are proposed from LPDL's management team to the executive team. Once the executive team approves, the executive team presents to the Board of Directors for approval.

Once the prioritization process is completed, budgets and proposed capital expenditures are prepared by LPDL's management team. These proposals are then submitted to the executive team for initial review and approval. This stage involves a detailed analysis of the projected financial implications, anticipated benefits, and alignment with LPDL's strategic objectives.

Upon receiving approval from the executive team, the proposed budgets and capital expenditures are presented to the Board of Directors. The Board reviews to ensure that every aspect of the proposed projects aligns with the company's long-term goals, regulatory requirements, and financial planning. This step is crucial as it guarantees the allocation of resources to projects that promise the highest returns in terms of system reliability, safety, and overall performance improvements.

Once the Board of Directors grants approval, the projects move forward to the execution phase, marking the transition from planning to implementation.

5.3.1.3.5 *Execute Maintenance & Capital Investment Plans*

Once the projects are approved, they are given to the engineering and operations teams to execute. Spending is monitored through our financial systems, Worktech and Great Plains.

5.3.1.3.6 *Monitor Asset Performance*

Assets are monitored for their performance after the project is completed through our regular asset management program, which includes maintenance and inspection.

5.3.1.4 Data

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

LPDL uses data from various tools and information to assist with its AM process such as asset registers, historical outage data, system load by station and feeder, system performance such as voltage stability, customer preferences, consultations with external parties.

5.3.1.4.1 *Asset Condition Assessment*

A primary component of LPDL's Asset Management (AM) process is the results of the Asset Condition Assessment (ACA).

LPDL employed Barkley Technology Inc. to carry out an ACA. The most recent ACA was conducted using 2024 data, ensuring that the latest and most relevant information was considered in the assessment. This comprehensive evaluation plays a critical role in informing LPDL's maintenance and capital investment decisions.

LPDL considers two main ratings when evaluating assets for replacement or refurbishment:

- Overall Risk Rating: This is a calculated rating that takes into consideration all variables shown in Table 5.3-22, including asset age, condition, historical performance data, and other pertinent factors such as system load and voltage stability. This holistic approach ensures that the assessment reflects the multifaceted nature of asset performance and risks.
- Asset Risk Rating: This rating focuses on specific aspects such as asset age and condition only, providing a more targeted view of the immediate physical state and potential failure risks of individual assets.

By integrating these ratings into the decision-making process, LPDL can prioritize investments and maintenance activities that optimize system reliability, safety, and performance. This structured approach not only aligns with regulatory requirements but also supports LPDL's strategic objectives of sustainable and efficient asset management.

Table 5.3-22: Asset Condition Variables

ASSET RISK	**Asset Age**
	Asset Condition
SYSTEM RISK	**System Impact**
BUSINESS RISK	**Number of Connected Customers**
PHYSICAL RISK	**Equipment Accessibility**
	Potential for Damage
CONSTRUCTION RISK	**Stock Availability**
	Equipment Availability
	Joint Use Attachments

5.3.1.4.2 *Inspection and Maintenance*

LPDL currently performs asset inspections in accordance with the DSC, ensuring compliance with industry regulations and best practices. These inspections are comprehensive, covering various aspects of asset functionality and condition. LPDL participated in a Utilities Standards Forum ("**USF**") working group, which produced the "Asset Inspection and Testing Recommendation Report." This report outlines standardized procedures and criteria for asset inspections, contributing to the consistency and reliability of the assessments.

Inspection records are gathered and maintained using a mobile application called Fulcrum. This application allows inspectors to record data on-site efficiently, reducing the likelihood of errors associated with manual entry. However, recognizing the need for continuous improvement, LPDL plans to transition to an ESRI-based application called Survey123 in 2025. Survey123 offers enhanced capabilities, including seamless data integration from inspectors' devices directly into the asset register. This transition aims to streamline the data management process, minimize human error, and save time, thereby increasing operational efficiency.

5.3.1.4.3 *System Loading & Capacity*

System loading and system capacity are paramount to LPDL's investment decisions. Ensuring that the distribution system can handle current and future demand is essential for maintaining reliability and efficiency. LPDL seeks to align its investments with OEB mandates, which require careful planning to accommodate future growth and changes in consumption patterns. This forward-looking approach is also in line with customer preferences, as identified in our latest survey, which underscores the importance of maintaining robust and adaptable infrastructure.

Detailed analyses of station and feeder loading, including peak load assessments and capacity utilization studies, are provided in Section 5.3.2.2.1. These analyses help identify areas where capacity upgrades or enhancements are needed to prevent overloading and to ensure that the system can sustain future demand without compromising service quality. Additionally, considerations of load distribution and the impact of potential failures on both system capacity and customer service are integral to LPDL's strategic planning.

By focusing on these critical aspects, LPDL can prioritize infrastructure investments that not only comply with regulatory requirements but also enhance system resilience and customer satisfaction. This comprehensive approach to system loading and capacity management is a cornerstone of our commitment to delivering reliable and efficient service to our customers.

5.3.1.4.4 *External Factors*

In addition to quantitative data, LPDL places significant emphasis on qualitative insights, such as customer preferences gathered through comprehensive surveys. This approach ensures that the decision-making process is aligned with the needs and expectations of our customers. Furthermore, LPDL actively coordinates with third-party entities, as detailed in Section 5.2.2, to enhance efficiency and align with strategic objectives. This collaborative effort not only facilitates informed business decisions but also fosters an environment of continuous improvement and operational excellence.

5.3.2 Overview of Assets Managed

Assessment of DSP requires a comprehensive understanding of all aspects of the assets managed by a distributor. Distributors may vary in terms of the level of detail that they choose to record for their distribution assets, but the expectation is that in assessing the condition of major assets (e.g., station transformers and poles), solely using asset age is not sufficient. A distributor should provide an overview of its distribution service area (e.g., system configuration; urban/rural; temperate/extreme weather; underground/overhead; fast/slow economic growth) pertinent for supporting its capital expenditures over the forecast period.

5.3.2.1 Description of Service Area

5.3.2.1.1 *Overview of Service Area*

LPDL owns, maintains and operates the distribution system covering a 147 sq. km. service territory of which 128 sq. km. is rural. LPDL distributes electricity within the municipalities of Bracebridge, Burk's Falls, Huntsville, Magnetawan, Sundridge and Parry Sound. LPDL's service territory is further detailed in Section 5.2.1.1.2.

LPDL's service area is within the colder and snowy climate regions of Muskoka and Parry Sound. Throughout the year, the temperature typically ranges from -30°C during the winter months to a 30°C in the summer. The area experiences significant snowfall, which impacts the maintenance and operation of the distribution system.

Heavy snowfall followed by warm temperatures poses a significant challenge to the maintenance and operation of the distribution system as the accumulated snow becomes dense and heavy. This added weight can cause tree branches to break and fall onto power lines, resulting in outages and requiring prompt repair efforts to restore service.

5.3.2.1.2 *Customers Served*

Table 5.3-23 summarizes the year-end customer counts for each rate class to highlight the changes in LPDL's customer base over the historical period. Residential customers account for LPDL's largest growth over the historical period, averaging around 1.44%. These trends in customer counts are reflective of development of residential subdivisions and condominiums in Bracebridge and Parry Sound.

Table 5.3-23: Changing Trends in Customer Base by Quantity

Customer Class	Historical					Forecast					
	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
Residential	11,430	11,566	11,726	11,912	12,125	12,262	12,400	12,540	12,681	12,823	12,968
GS<50	2,154	2,155	2,191	2,205	2,206	2,218	2,229	2,242	2,254	2,265	2,277
50≥GS<5000	137	136	131	129	130	126	122	121	119	117	114
Sentinels	41	40	40	38	33	31	29	27	25	23	21
Streetlights	2,849	2,851	2,851	2,851	2,851	2,852	2,853	2,853	2,853	2,853	2,853
USL	55	56	65	64	63	64	65	64	64	64	64
Total Excl. SL	**13,817**	**13,953**	**14,153**	**14,348**	**14,557**	**14,701**	**14,845**	**14,994**	**15,142**	**15,292**	**15,444**
Total	**16,666**	**16,804**	**17,004**	**17,199**	**17,408**	**17,553**	**17,698**	**17,847**	**17,995**	**18,145**	**18,297**

LPDL anticipates a modest customer growth rate of approximately 1% over the forecast period. Furthermore, a decline has been observed in the number of General Service customers with demand greater than 50 kW but less than 5000 kW within its service area. Table 5.3-24 provides a detailed summary of the growth rates by customer class, expressed as a percentage.

Table 5.3-24: Changing Trends in Customer Base by Percentage

Customer Class	Historical					Average
	2019	2020	2021	2022	2023	
Residential	1.25%	1.19%	1.38%	1.59%	1.79%	1.44%
GS<50	-0.23%	0.05%	1.67%	0.64%	0.05%	0.43%
50≥GS<5000	-0.72%	-0.73%	-3.68%	-1.53%	0.78%	-1.18%
Sentinels	-6.82%	-2.44%	0.00%	-5.00%	-13.16%	-5.48%
Streetlights	0.00%	0.07%	0.00%	0.00%	0.00%	0.01%
USL	7.84%	1.82%	16.07%	-1.54%	-1.56%	4.53%

5.3.2.1.3 SYSTEM DEMAND & EFFICIENCY

Table 5.3-25 shows the annual peak demand for summer and winter, in kilowatts (kW), as well as the average annual peak from 2019 to 2023. LPDL experiences its overall system peak during the winter months due to our cold climate and prevalence of electric heat in some municipalities.

Table 5.3-25: Peak System Demand Statistics

Year	Winter Peak with Embedded Generation (kW)	Summer Peak with Embedded Generation (kW)	Average Peak (kW)	Winter Peak without Embedded Generation (kW)	Summer Peak without Embedded Generation (kW)	Average Peak (kW)
2023	51,429	45,232	40,604	57,572	49,330	47,473
2022	51,997	46,374	43,383	57,926	48,219	48,339
2021	45,458	48,124	39,145	51,626	49,930	46,008
2020	46,957	47,322	39,178	55,704	48,925	46,954
2019	50,163	45,670	39,175	56,596	46,981	46,038

As shown in the table above, summer peaks have increased steadily, reflecting the overall growth in energy demand due to heightened usage of air conditioning systems and other cooling devices during the warmer months. Winter peaks, on the other hand, display less consistency, fluctuating based on the severity of the cold season. This variability is influenced by the intensity of heating requirements, which depend significantly on the winter's harshness. Despite the recent trend of milder winters, which has somewhat moderated winter peak demands, LPDL continues to prepare for potential spikes in energy consumption during particularly cold periods.

As seen when comparing Table 5.3-26 to Table 5.3-27, HONI Transmission losses continue to be a significant contribution to overall efficiency numbers, increasing the LPDL Losses as % of Purchased by 2.25 to 2.46%. LPDL has several initiatives to address line losses, including converting 4kV lines to 27.6kV.

Table 5.3-26: Efficiency of kWh Purchased by LPDL (Excl. Transmission Losses)

Annual Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2023	289,860,629	302,995,540	4.53%
2022	286,230,671	298,392,705	4.25%
2021	290,240,292	303,287,862	4.50%
2020	303,102,277	315,241,272	4.00%
2019	296,977,680	308,430,877	3.86%

Table 5.3-27: Efficiency of kWh Purchased by LPDL (Incl. Transmission Losses)

Annual Year	Total kWh Delivered (excluding losses)	Total kWh Purchased	Losses as % of Purchased
2023	289,860,629	309,952,095	6.93%
2022	286,230,671	304,387,702	6.34%
2021	290,240,292	309,941,422	6.79%
2020	303,102,277	322,673,989	6.46%
2019	296,977,680	315,137,434	6.11%

5.3.2.1.4 *Summary of System Configuration*

LPDL owns a total of ten municipal substations ("MS"). Four of the substations (Bracebridge MS3, Centennial MS, Douglas MS and Golden Beach MS) are in the territory of Bracebridge, 2 of them (Huntsville MS1 and Huntsville MS2) are in the territory of Huntsville, and the remaining four (Parry Sound MS1, Parry Sound MS3, Parry Sound MS4 and Parry Sound MS5) are in the territory of Parry Sound.

Table 5.3-28 provides a summary of the ten municipal substations owned by LPDL.

Table 5.3-28: LPDL Municipal Substation Details

Substation Name	# of Transformers	Installed Capacity (MVA)	Voltage	# of Reclosers	# of Feeders
Centennial MS	1	10 MVA	44kV/27.6kV	3	3
Douglas MS	1	5 MVA	44kV/27.6kV	2	2
Golden Beach MS	1	10 MVA	44kV/27.6kV	2	2
Bracebridge MS3	1	5 MVA	44kV/4.16kV	0	3
Parry Sound MS1	1	5 MVA	44kV/4.16kV	2	2
Parry Sound MS3	1	10 MVA	44kV/12.47kV	2	2
Parry Sound MS4	1	5 MVA	44kV/4.16kV	0	4
Parry Sound MS5	1	10 MVA	44kV/12.47kV	3	3
Huntsville MS1	1	7.5 MVA	44kV/4.16kV	0	5
Huntsville MS2	1	8 MVA	44kV/4.16kV	0	4

As of 2024, both overhead ("**OH**") and underground ("**UG**") distribution systems are employed in LPDL's service territory. Currently, LPDL owns 394 km of primary conductors' length, of which

290km is OH primary conductor and 104km is UG primary cable. The number of circuits at each voltage level as well as the associated conductor lengths are summarized in Table 5.3-29.

Table 5.3-29: Circuit Length by Voltage Level

Voltage Level	Number of Circuits	Underground Cable Length (km)	Overhead Conductor Length (km)	Total Circuit Length (km)
4.16kV	22	12.2	45.3	57.5
12.47kV	16	35.7	201.1	236.8
27.6kV	7	56.4	43.7	100.1
Total	**45**	**104.3**	**290.1**	**394.4**

5.3.2.2 Asset Information

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

5.3.2.2.1 *Asset Capacity and Utilization*

The evaluation of system utilization involves comparing the peak load of each feeder and station transformer to their respective ratings. Feeders are assessed on their calculated ampacity, while station transformers are based on their nameplate capacity.

The following table summarizes LPDL's station capacity and utilization during the historical period.

Table 5.3-30: Station Capacity and Utilization

Voltage	Station	Capacity (kVA)	2018 (kVA)	2019 (kVA)	2020 (kVA)	2021 (kVA)	2022 (kVA)	2023 (kVA)	2024 Summer (kVA)
27.6kV	Centennial	10000	11189	8517	7426	10712	10444	5808	
	Golden Beach	10000	9250	8286	6225	6007	9606	5874	14768
	Douglas	5000	5350	1705	1692	1912	2040	2101	3434
12.47kV	Parry Sound MS3	10000	5269	5423	5809	5266	6726	5588	5304
	Parry Sound MS5	10000	2942	3473	4072	2406	2541	4688	2435
4.16kV	Bracebridge MS3*	5000	1364	1327	1162	1279	1728	1335	1275
	Huntsville MS1	7500	4680	6736	5144	6560	4073	4583	5572
	Huntsville MS2	8000	5299	3427	3349	3325	4138	3595	3039
	Parry Sound MS1*	5000	2713	2769	2488	2264	2652	2622	2404
	Parry Sound MS4	5000	3032	3741	3358	3360	6952	4984	5891

Prior to 2024, all of LPDL's stations utilized less than 100% of their full capacity. However, in 2024, LPDL experienced a critical failure at its most crucial substation, Centennial MS. This failure resulted in significant operational challenges, and at the time of filing, LPDL is still in the midst of repair and/or procurement processes, contingent upon investigative results and dealings with our insurance company.

The failure of Centennial MS created substantial difficulty in providing voltage stability for our customers. Fortunately, due to higher-than-normal rainfall in June 2024, additional Distributed Energy Resource (DER) support was available from our subsidiary's hydro-electric plants, which mitigated some of the impact on our grid stability during this period. The continued investigation and repair efforts are crucial for restoring full operational capacity and ensuring reliable service delivery to our customers.

These challenges underscore the critical necessity of constructing a new 27.6kV substation to replace Bracebridge MS3.

The following table summarizes LPDL's maximum feeder ampacity and calculated peak amperages in both the summer and winter months.

Table 5.3-31: Feeder Maximum Ampacity and Utilization

Voltage Level	Feeder	Feeder Limit (A)	2019		2020		2021		2022		2023	
			S	W	S	W	S	W	S	W	S	W
27.6kV	Centennial - F1	240	152	98	91	196	116	188	183	134	89	99
	Centennial - F2	240	18	23	21	22	20	23	60	33	21	24
	Centennial - F3	240	20	22	21	19	18	20	47	28	19	18
	Golden Beach - F6	245	158	132	124	97	125	110	200	162	117	116
	Douglas - F2	245	36	27	37	31	41	34	41	45	45	35
12.47kV	Parry Sound MS3 - F1	360	135	124	149	141	95	100	92	117	92	111
	Parry Sound MS3 - F2	360	106	154	119	130	116	150	112	133	125	149
	Parry Sound MS5 - F2	280	19	23	18	21	17	22	14	23	15	36
	Parry Sound MS5 - F3	280	30	38	32	33	31	38	33	39	32	56
4.16kV	Bracebridge MS3 - F1	400	40	44	43	47	44	63	43	50	46	49
	Bracebridge MS3 - F2	400	24	35	30	36	30	55	30	39	31	38
	Bracebridge MS3 - F3	400	63	93	68	84	67	121	71	96	73	92
	Huntsville MS1 - F1	400	103	153	116	158	117	179	116	205	116	169
	Huntsville MS1 - F2	400	305	247	94	125	360	150	311	145	168	214
	Huntsville MS1 - F3	400	186	209	111	115	99	136	111	137	115	199
	Huntsville MS1 - F4	400	281	99	113	84	315	98	105	100	113	257
	Huntsville MS1 - F5	400	45	56	40	55	47	52	50	53	58	50
	Huntsville MS2 - F1	400		125	163	119	172	136	177	129	173	138
	Huntsville MS2 - F2	400		123	68	62	66	66	64	172	63	162
	Huntsville MS2 - F3	400	226	204	157	175	154	212	139	234	144	166
	Huntsville MS2 - F4	400	87	72	95	68	206	79	90	88	92	72
	Parry Sound MS1 - F1	400	139	185	135	159	139	185	125	193	134	167
	Parry Sound MS1 - F2	400	92	164	104	166	107	196	105	188	116	176
	Parry Sound MS4 - F1	400	110	151	127	154	127	177	203	205	222	183
	Parry Sound MS4 - F2	400	85	89	85	79	82	91	198	82	200	276
	Parry Sound MS4 - F3	400	96	73	45	66	48	74	129	76	151	195
	Parry Sound MS4 - F4	400	169	160	117	172	118	176	111	178	319	169

Most of the feeders supplying LPDL are moderately loaded with enough capacity to address emergency and capacity demands.

Table 5.3-32 illustrates average power factors at the feeder level. Due to the large amount of DERs on Centennial-F1, Golden Beach-F6, and Parry Sound MS3-F1, power factor readings will average slightly lower than actuals due to the synchronous generators on the line.

LPDL is currently investigating where it may recommend capacitor banks to customers contributing to poor power factor, and where we may be able to implement our own.

Table 5.3-32: Summer/Winter Average Power Factor by Substation

Voltage Level	Feeder	Feeder Limit (A)	2019		2020		2021		2022		2023	
			S	W	S	W	S	W	S	W	S	W
27.6kV	Centennial - F1	240	0.90	0.89	0.80	0.91	0.85	0.90	0.93	0.92	0.79	0.88
	Centennial - F2	240	0.94	0.96	0.96	0.97	0.95	0.97	0.95	0.96	0.95	0.96
	Centennial - F3	240	0.98	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99	0.99
	Golden Beach - F6	245	0.93	0.91	0.78	0.91	0.79	0.95	0.95	0.91	0.86	0.91
	Douglas - F2	245	0.99	1.00	1.00	0.99	0.99	0.99	0.99	0.98	0.99	0.98
12.5kV	Parry Sound MS3 - F1	360	0.95	0.99	0.90	0.86	0.84	0.86	0.94	0.72	0.87	0.75
	Parry Sound MS3 - F2	360	0.93	0.97	0.94	0.98	0.95	0.98	0.95	0.98	0.95	0.98
	Parry Sound MS5 - All	280	0.93	0.98	0.97	0.98	0.93	0.98	0.94	0.98	0.95	0.98
4.16kV	Huntsville MS1 - F1	400	0.96	0.99	0.96	0.99	0.97	0.99	0.97	0.99	0.97	0.99
	Huntsville MS1 - F2	400	0.90	0.94	0.88	0.91	0.86	0.93	0.87	0.93	0.87	0.97
	Huntsville MS1 - F3	400	0.89	0.94	0.94	0.97	0.95	0.97	0.94	0.98	0.94	0.93
	Huntsville MS1 - F4	400	0.92	0.96	0.92	0.96	0.93	0.97	0.93	0.96	0.93	0.96
	Huntsville MS1 - F5	400	0.92	0.96	0.93	0.96	0.94	0.97	0.94	0.96	0.94	0.96
	Huntsville MS2 - F1	400		0.68	0.60	0.76	0.66	0.81	0.69	0.81	0.71	0.83
	Huntsville MS2 - F2	400		0.67	0.60	0.69	0.59	0.75	0.58	0.78	0.62	0.81
	Huntsville MS2 - F3	400	0.93	0.98	0.96	0.99	0.96	0.99	0.96	0.99	0.96	0.99
	Huntsville MS2 - F4	400	0.86	0.92	0.87	0.93	0.88	0.94	0.89	0.93	0.88	0.93
	Parry Sound MS4 - F1	400	0.96	0.97	0.92	0.97	0.93	0.98	0.93	0.98	0.94	0.97
	Parry Sound MS4 - F2	400	0.90	0.98	0.92	0.97	0.91	0.98	0.94	0.97	0.94	0.98
	Parry Sound MS4 - F3	400	0.96	0.99	0.96	0.99	0.96	0.99	0.95	0.99	0.95	0.99
	Parry Sound MS4 - F4	400	0.92	0.99	0.96	0.99	0.96	0.99	0.97	0.99	0.97	0.99

5.3.2.2.2 Asset Condition and Demographics

ACA data was originally produced in 2022 and was updated with the latest data in 2024. The study was carried out by Barkley Technology Inc. and LPDL to establish the health and condition of distribution assets in-service.

The DSP will focus on two main results of the ACA: the Asset Risk, which serves as a health index indicating the condition and potential issues of each asset, and the Overall Risk, which amalgamates all the collected data to provide a comprehensive risk rating. This approach ensures that the evaluation is both detailed and holistic, taking into account various factors that contribute to the overall reliability and safety of the distribution system. Figure 5.3-20 and Figure 5.3-21 present the summary results of the ACA in 2024.

Figure 5.3-20: Distribution Overall Risk Results

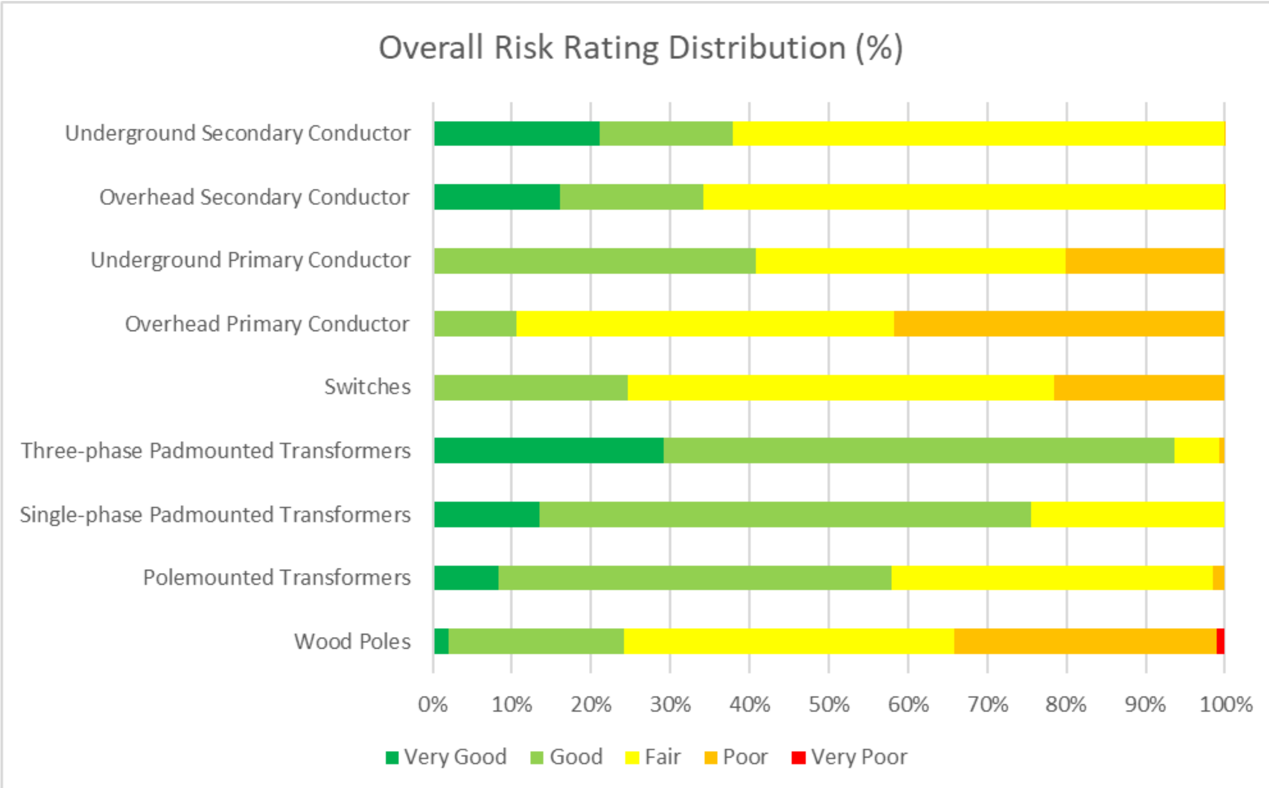
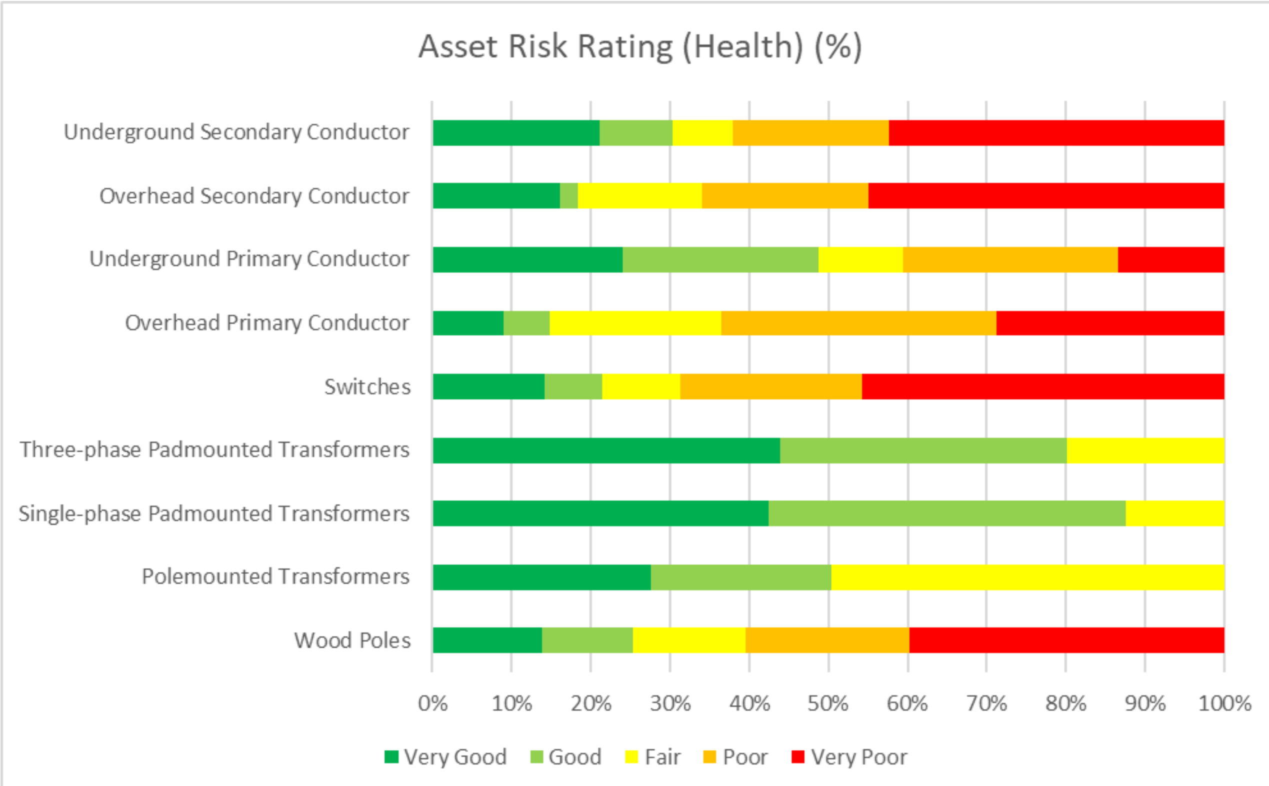


Figure 5.3-21: Distribution Asset Risk Results



Prior to formally conducting the ACA, LPDL has historically considered an asset's system impact when identifying assets for replacement. For instance, poles supporting multiple circuits, particularly sub-transmission circuits, are generally deemed higher risk due to their potential to affect a significant number of customers upon failure. Consequently, Figure 5.3-20 illustrates that LPDL's system exhibits relatively low overall risk.

Conversely, a substantial number of aging assets have been assigned ratings of Very Poor. The disparity between Overall Risk and Asset Risk arises because many assets classified as Very Poor are those with minimal customer impact upon failure, such as radial-feed poles in rural areas or service poles.

LPDL remains committed to enhancing its ACA throughout its duration. This commitment includes incorporating more rigorous physical condition assessments, such as pole testing, and carefully considering the weighting of data to ensure the accuracy and reliability of the assessment.

5.3.2.2.2.1 WOOD POLES

LPDL owns 6,366 wood poles within its territory. While many of these poles are categorized under a poor Overall Risk Rating, very few are rated as Very Poor. In contrast, a significant number of poles have an Asset Risk Rating of Very Poor. The majority of these high-risk poles are situated in rural or densely wooded areas, or serve as service poles for single customers.

A summary of the Overall Risk Rating and the Asset Risk Rating of Wood Poles are shown in Figure 5.3-22 and Figure 5.3-23.

Figure 5.3-22: Wood Pole Overall Risk Rating

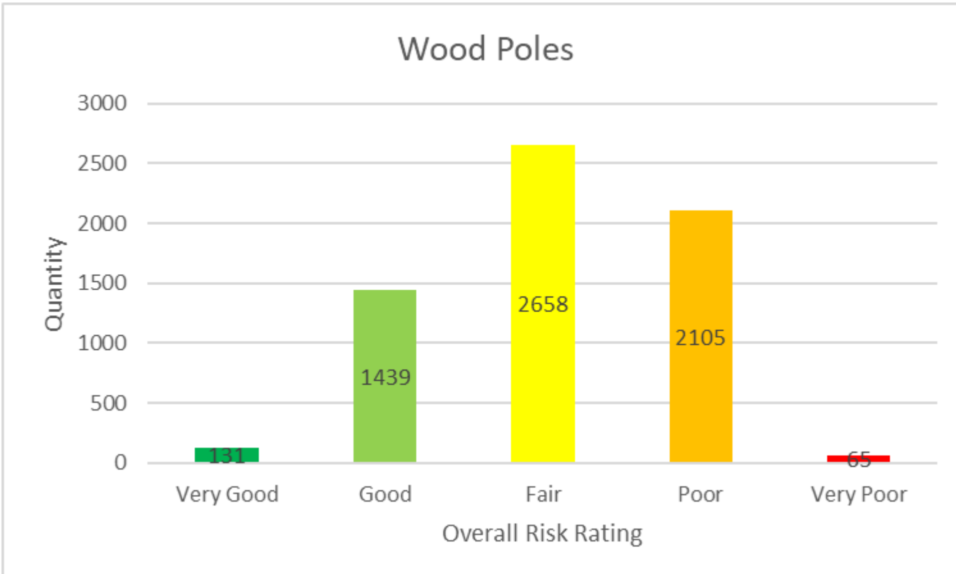


Figure 5.3-23: Wood Pole Asset Risk Rating

5.3.2.2.2.2 Polemounted Transformers

LPDL owns 2,145 polemounted transformers within its territory. These transformers are considered relatively low risk regarding public safety and reliability. Typically, failures of these transformers impact between 1 and 15 customers, minimizing widespread disruption. Despite their critical role in the distribution network, polemounted transformers do not frequently experience failures, contributing to their low-risk assessment. This prioritization ensures that resources can be effectively allocated to more critical and vulnerable components within the system, enhancing overall network stability and performance.

A summary of the Overall Risk Rating and the Asset Risk Rating of Polemounted Transformers are shown in Figure 5.3-24 and Figure 5.3-25

Figure 5.3-24: Polemounted Transformers Overall Risk Rating

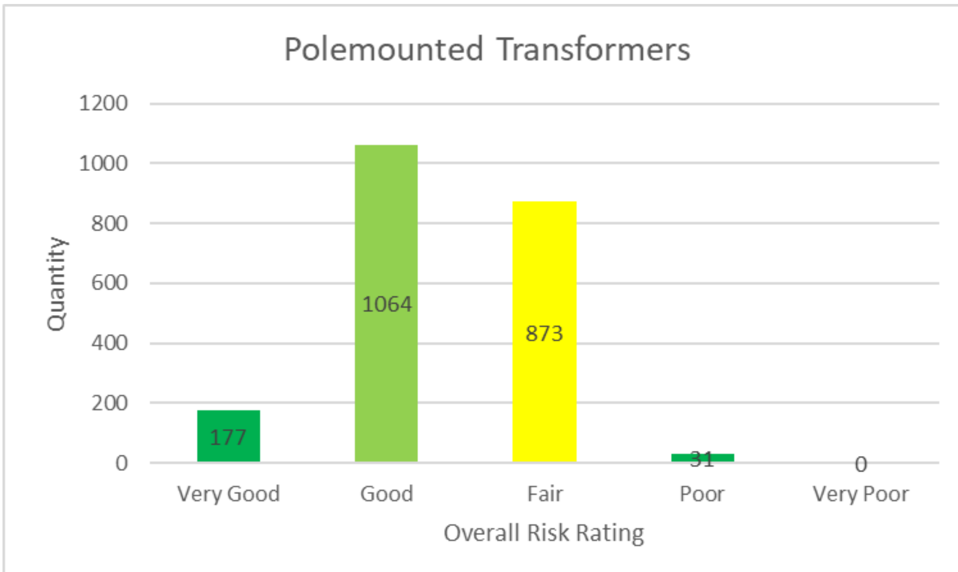
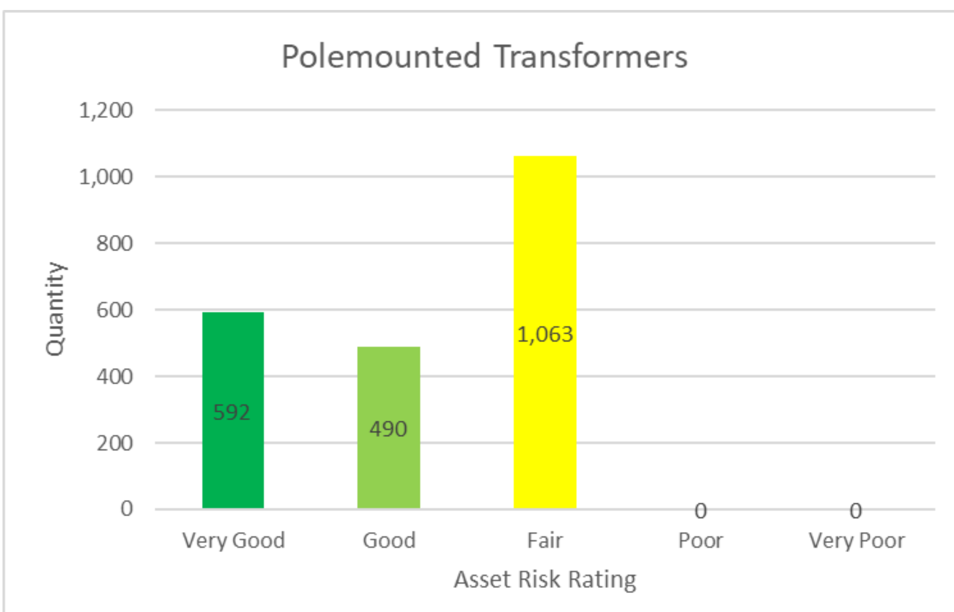


Figure 5.3-25: Polemounted Transformers Asset Risk Rating



5.3.2.2.2.3 Single-Phase Padmounted Transformers

LPDL owns 428 single-phase padmounted transformers within its territory. These transformers are considered relatively low risk regarding public safety and reliability. Typically, failures of these transformers impact between 1 and 12 customers, minimizing widespread disruption. Failures that do occur typically result in a blown fuse, mitigating public and safety concerns.

A summary of the Overall Risk Rating and the Asset Risk Rating of Single-Phase Padmounted Transformers are shown in Figure 5.3-26 and Figure 5.3-27.

Figure 5.3-26: Single-phase Padmounted Transformers Overall Risk Rating

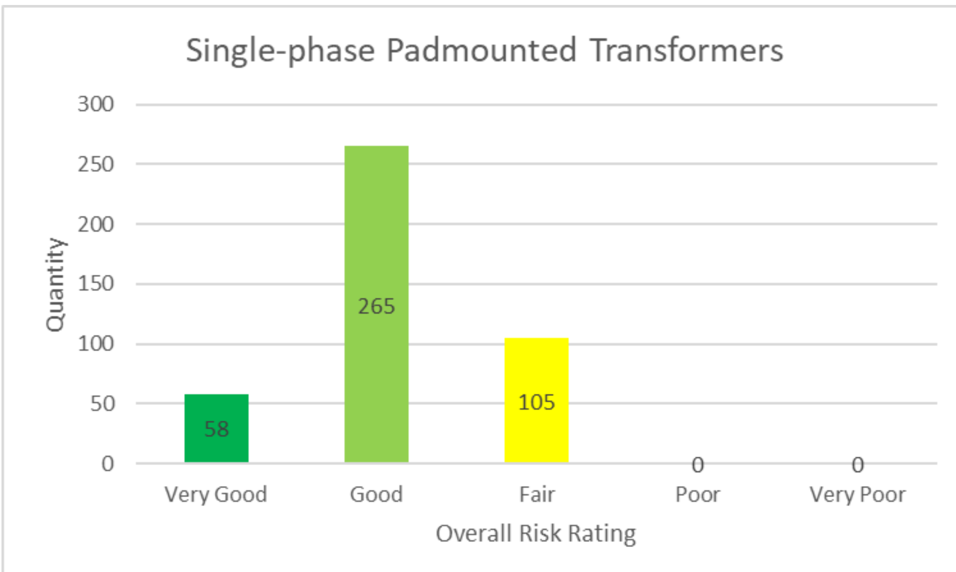
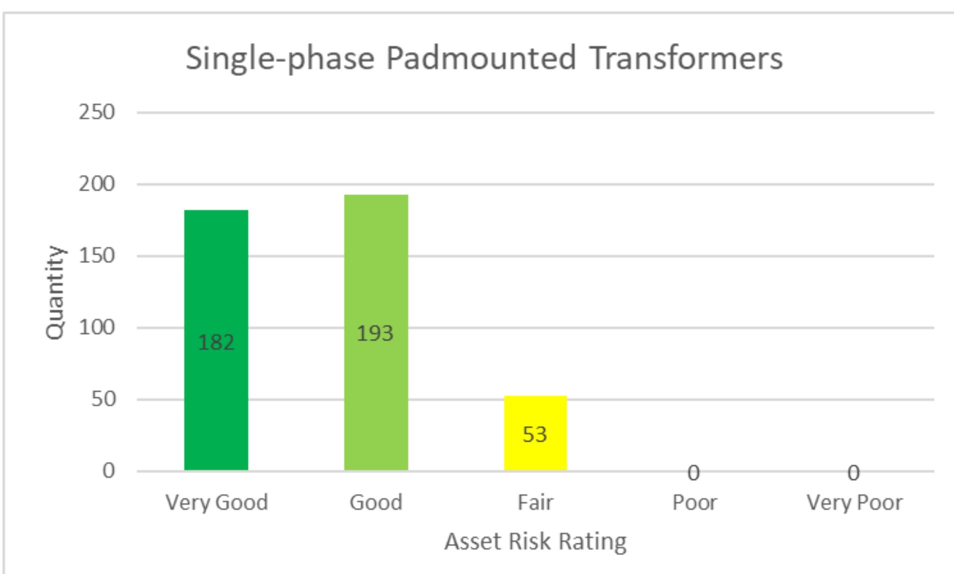


Figure 5.3-27: Single-phase Padmounted Transformers Asset Risk Rating



5.3.2.2.2.4 THREE-PHASE PADMOUNTED TRANSFORMERS

LPDL owns 141 three-phase padmounted transformers within its territory. These transformers are assessed as relatively low risk concerning public safety and reliability. Typically, failures of these transformers affect between 1 and 3 dwellings, with variability in customer impact particularly in settings such as condominiums. When failures do occur, they generally result in a blown fuse, thereby mitigating public and safety concerns.

A summary of the Overall Risk Rating and the Asset Risk Rating of Three-Phase Padmounted Transformers are shown in Figure 5.3-28 and Figure 5.3-29.

Figure 5.3-28: Three-phase Padmounted Transformers Overall Risk Rating

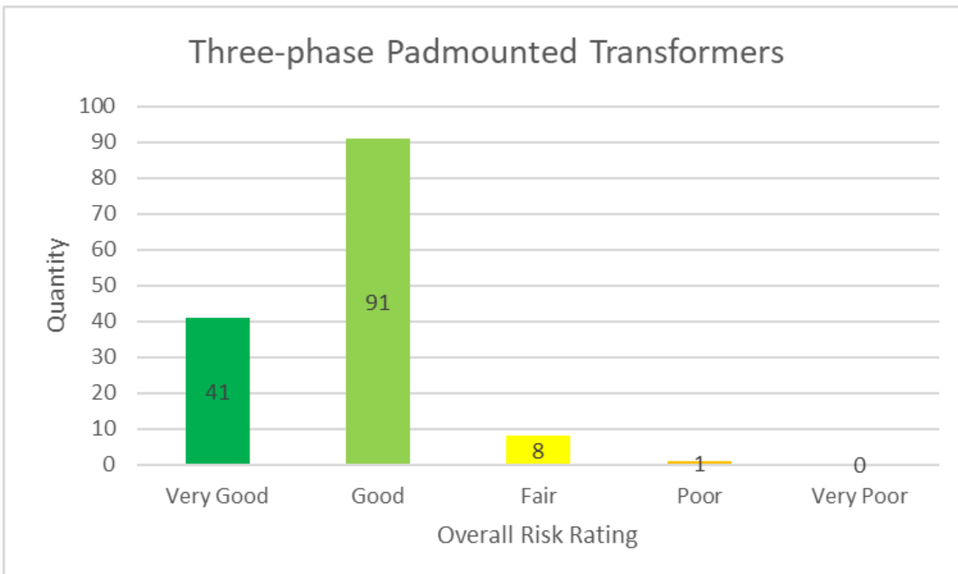
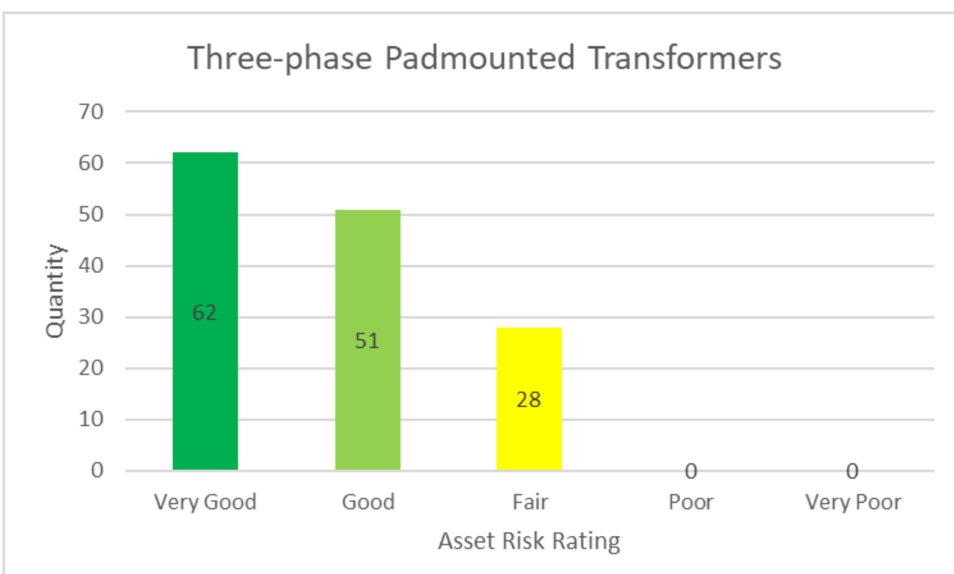


Figure 5.3-29: Three-phase Padmounted Transformers Asset Risk Rating



5.3.2.2.2.5 Switches

LPDL owns and operates 943 switches in its territory. Currently, the list of switches encompasses all operable switches including fused and solid-blade overhead switches, switchgear, ganged load-break switches, and some reclosers. Despite LPDL's ACA considering only 15 switches to have an Overall Risk Rating of Very Poor, LPDL's judgement is that ongoing porcelain switch replacements are crucial to the improvement of public safety and reliability of the system.

LPDL owns and operates 943 switches within its territory. The inventory includes a variety of operable switches such as fused and solid-blade overhead switches, switchgear, ganged load-break switches, and reclosers. These switches are critical for managing the distribution network, allowing for sectionalizing and isolating faults to maintain system reliability. While these assets are currently grouped, LPDL feels it will be beneficial to it's future ACA to separate these items.

Although LPDL's ACA has identified only 15 switches with an Overall Risk Rating of Very Poor, it is deemed essential by LPDL to continue the replacement of aging porcelain switches with polymer switches. This ongoing effort is vital to enhancing the public safety and reliability of the electrical system, as outdated porcelain switches can be more prone to failure, leading to potential disruptions and safety hazards.

A summary of the Overall Risk Rating and the Asset Risk Rating of Switches are shown in Figure 5.3-30 and Figure 5.3-31.

Figure 5.3-30: Switches Overall Risk Rating

Figure 5.3-31: Switches Asset Risk Rating

5.3.2.2.2.6 Overhead Primary Conductor

LPDL owns approximately 291km of primary overhead conductor in its service territory. Overall Risk Ratings are relatively low, with none being identified as Very Poor. In contrast, 74km of overhead primary conductor is rated Very Poor on the Asset Risk Rating.

LPDL undertakes numerous small projects aimed at replacing outdated copper primary wires. These replacement projects are typically completed in incremental stages to maximize efficiency and minimize disruption. The work is often scheduled to coincide with other planned activities in the area, allowing for a more integrated approach to infrastructure improvement.

Additionally, working on copper conductors smaller than #2 AWG while they are energized is considered poor utility practice. As such, performing maintenance or upgrades in areas with these smaller copper wires necessitates planned outages to ensure the safety of workers and the integrity of the system. By replacing these outdated conductors with newer aluminum conductor, LPDL can reduce the frequency of these scheduled outages, thereby enhancing service continuity and reliability for customers.

A summary of the Overall Risk Rating and the Asset Risk Rating of Overhead Primary Conductors are shown in Figure 5.3-32 and Figure 5.3-33.

Figure 5.3-32: Overhead Primary Conductor Overall Risk Rating

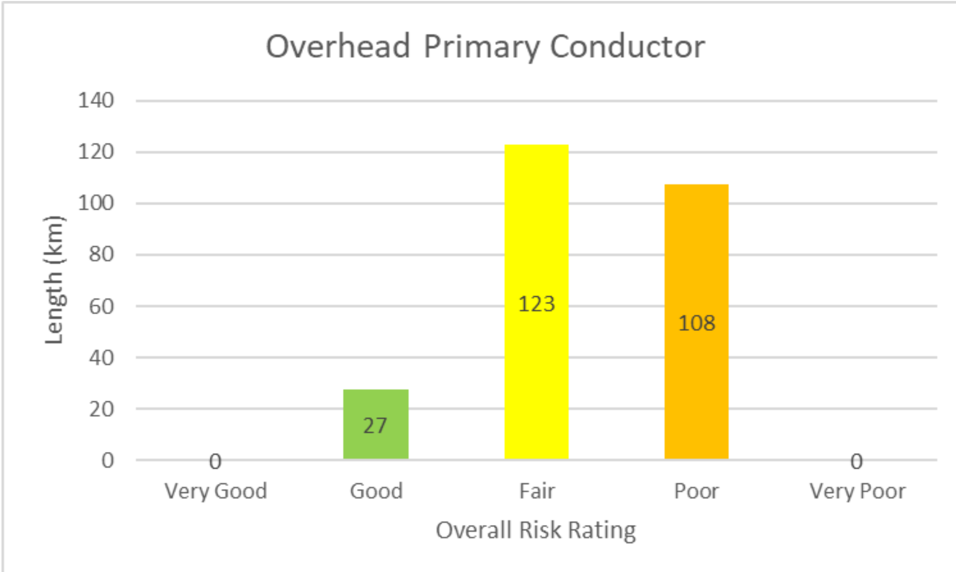
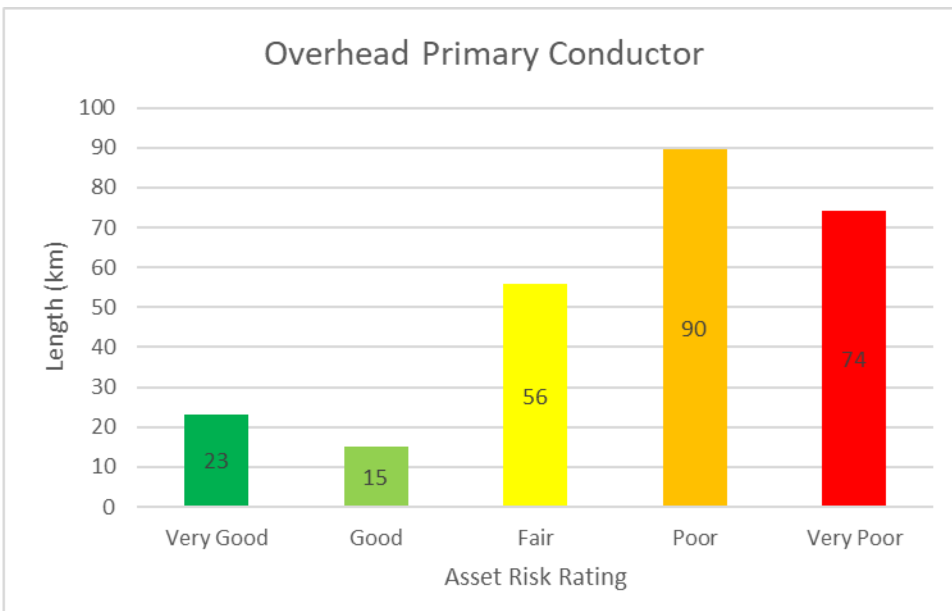


Figure 5.3-33 Overhead Primary Conductor Asset Risk Rating



5.3.2.2.2.7 Underground Primary Conductor

LPDL owns approximately 101km of primary overhead conductor in its service territory. Overall Risk Ratings are relatively low, with none being identified as Very Poor. In contrast, 14km of overhead primary conductor is rated Very Poor on the Asset Risk Rating. Condition data is very limited for underground primary conductors.

Nonetheless, LPDL feels it is prudent to undergo some capital underground rebuild projects. Reactive replacement of underground primary conductor can be exceedingly expensive, especially because most cable over 30 years old is direct buried. By proactively addressing these aging infrastructure issues, LPDL aims to avoid the higher costs and service interruptions associated with emergency repairs. These planned upgrades will not only enhance the reliability and safety of the system but also extend the lifespan of the underground network, ensuring a more stable and efficient power delivery to customers.

Figure 5.3-34: Underground Primary Conductor Overall Risk Rating

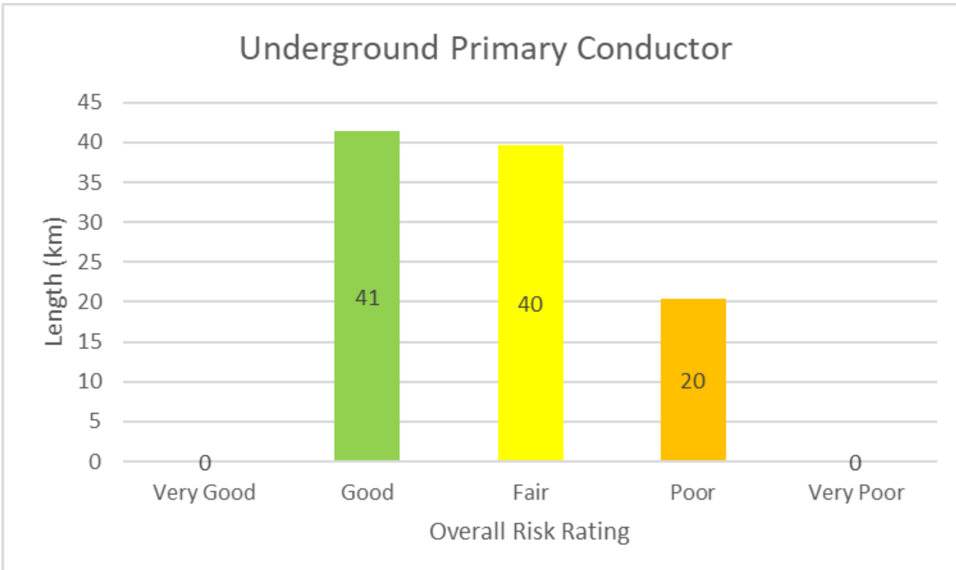
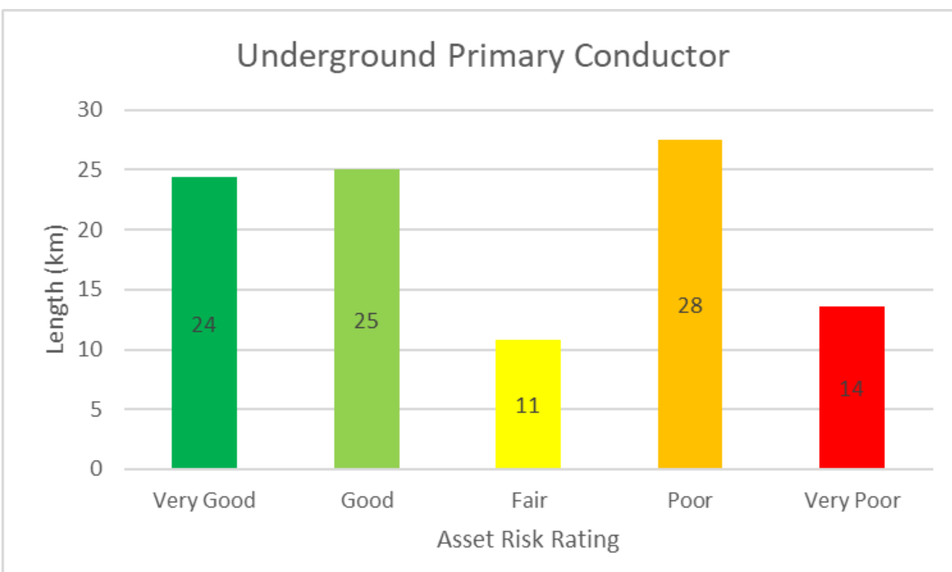


Figure 5.3-35: Underground Primary Conductor Asset Risk Rating



5.3.2.2.2.8 Overhead Secondary Conductor

LPDL owns approximately 289km of overhead secondary conductor in its service territory. Overall Risk Ratings are relatively low, with none being identified as Poor or Very Poor. In contrast, 130km of overhead secondary conductor is rated Very Poor on the Asset Risk Rating.

Condition data is limited for overhead secondary conductors. LPDL replaces overhead secondary conductors for capacity reasons, but not proactively due to age or condition.

Figure 5.3-36: Overhead Secondary Conductor Overall Risk Rating

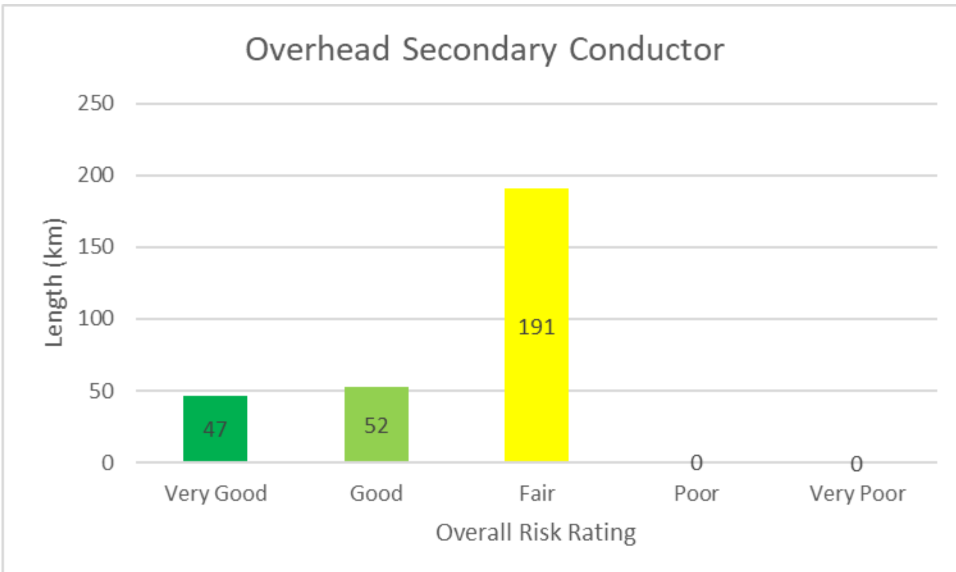
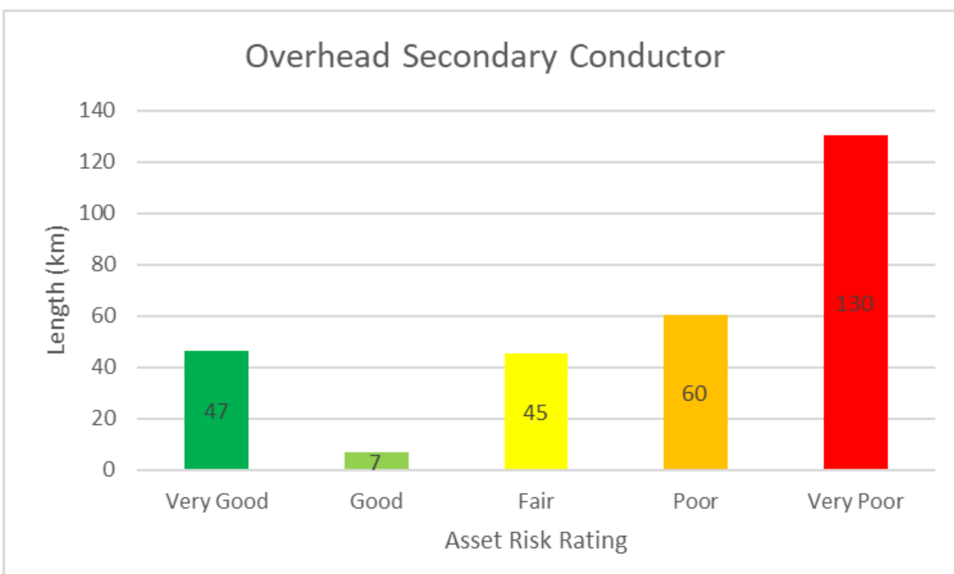


Figure 5.3-37: Overhead Secondary Conductor Asset Risk Rating



5.3.2.2.2.9 Underground Secondary Conductor

LPDL owns approximately 232km of underground secondary conductor in its service territory. Overall Risk Ratings are relatively low, with none being identified as Poor or Very Poor. In contrast, 130km of underground primary conductor is rated Very Poor on the Asset Risk Rating.

Condition data is limited for underground secondary conductors. LPDL replaces overhead secondary conductors for capacity reasons, but not proactively due to age or condition.

Figure 5.3-38: Underground Secondary Conductor Overall Risk Rating

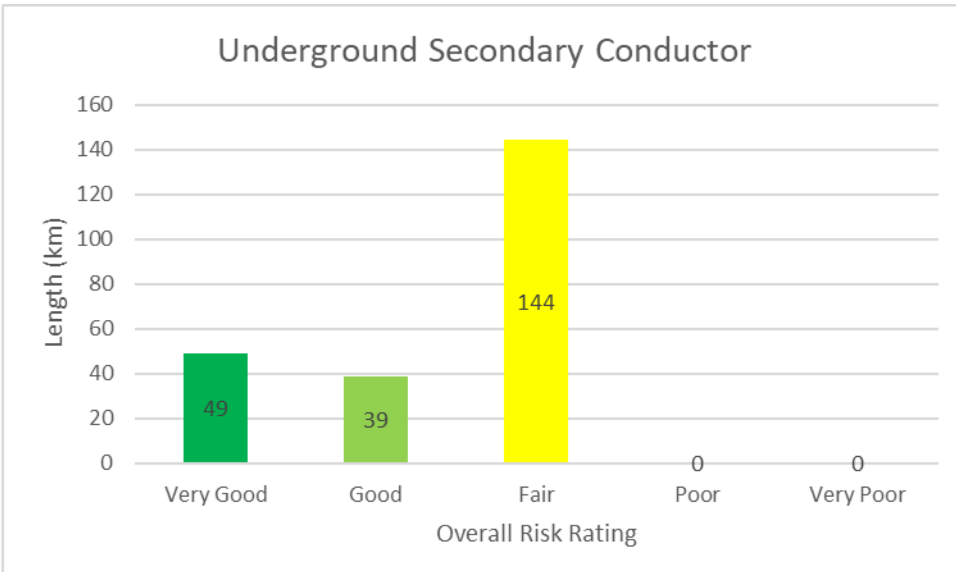
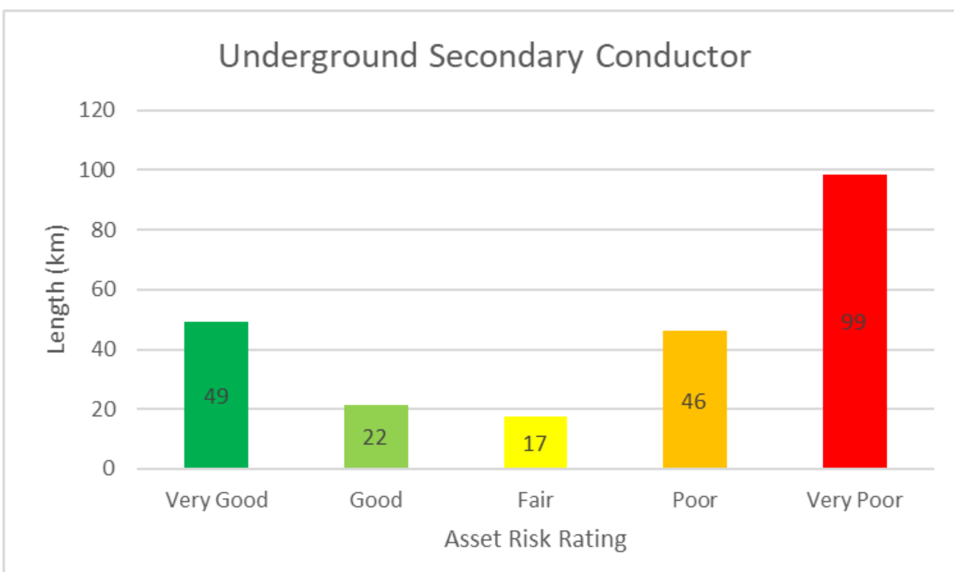


Figure 5-3.39: Underground Secondary Conductor Asset Risk Rating



5.3.2.2.3 *Asset Risks*

LPDL's AM process manages a fixed asset's entire life cycle, from specifying and installing the asset to its preventative maintenance and end-of-life retirement. This involves balancing maximum life expectancy, top performance, minimal capital costs, and low operating expenses. Asset risks are also assessed to help prioritize capital projects and programs. More details are available in Section 5.3.1.3.

5.3.2.3 Transmission or High Voltage Assets

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

LPDL does not own or operate any transmission assets.

5.3.2.4 Host & Embedded Distributors

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

LPDL is fully embedded within HONI and has no transmission-connected assets.

5.3.3 Asset Lifecycle Optimization Policies and Practices

LPDL manages assets with the intent of providing a safe, reliable, efficient, and cost-effective distribution system.

Electricity assets, like any other type of physical asset, have a lifecycle. For example, distribution transformers are manufactured with the intent that there is no need to provide regular maintenance for the duration of their lifecycle. However, a small percentage of distribution assets, such as substation transformers, do require regular maintenance. Components wear out in a number of ways including oxidation, pitting or erosion. Elements leading to failure involve a number of factors, such as quality of manufacture, installation, age, operating hours, loading cycles, temperature, contaminants and stress. LPDL has a maintenance and inspection program in place for early detection of problems.

LPDL replaces wires, poles, and transformers that are over 40+ years old and have used that as a benchmark for planning the O&M work. LPDL tends to prioritize voltage conversion to their capital expenditures but do budget a certain amount for each town for “Assets over 40 years old”. At times both the voltage conversion capital work go hand in hand with the routine O&M, meaning that LPDL convert from our 4.2 kV stations to 12.5 kV or 27.6 kV, while also replacing 40 year old assets at the same time.

5.3.3.1 Asset Replacement and Refurbishment Policy

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

A Distribution System Maintenance and Inspection Program is a key component to system reliability, customer/public safety and worker safety. This program provides base knowledge to make informed decisions and identify any future upgrades. The data collected also provides valuable information upon which to base risk assessment of the cost to repair vs cost to replace. This includes failure leading to downtime, safety and other assets impacted. This leads to plans for repair work, refurbishment activities and asset replacement schedules. LPDL will evaluate cost-benefits of refurbishment vs replacement for each applicable project and make decisions in benefit of business and customers. For example, replacing is sometimes more prudent, even when more expensive, because if a station power transformer experienced an unplanned failure, it could result in many customers being interrupted for a significant period of time and could pose safety risks to the public and staff if an explosion or fire occurred. If the issue is with a minor part of the larger asset, such as cracked or damaged bushings in a transformer, then that ‘repair’ would be sufficient. Immediate replacement may offer the opportunity to refurbish the asset and re-deploy. Each occurrence is analyzed individually based on the type of fault, asset age, current condition and impact on the system.

LPDL’s asset replacement and refurbishment policies for each class of assets are summarized below.

5.3.3.1.1 *Substations*

LPDL has a program of monthly substation inspection and annual oil testing. LPDL retains a third-party consultant to perform DGA on its substation transformers and tap changers. Third-party consultant recommendations will be evaluated to decide whether to continue re-testing, schedule shut-downs for investigation or plan for replacement.

Capital investments on substation assets are typically based on a proactive approach. Maintaining substations over the long term adds system O&M costs, Amalgamating the 4 Parry Sound substations into 3 would eliminate some of that O&M costs.

5.3.3.1.2 *Distribution Transformers*

The majority of LPDL's distribution transformers are pole mounted. All distribution transformers are inspected and monitored regularly and replaced on a proactive and/or reactive basis. Small deficiencies are repaired during inspections or scheduled for a follow-up repair, but more severe deterioration necessitates replacement. Failed transformers will be replaced immediately to restore power.

5.3.3.1.3 *Poles*

LPDL's overhead lines are all supported by wood poles. Poles are regularly inspected and corrective action is taken as needed on flagged issues. Pole replacements are budgeted each year and the inspection process identifies individual poles for replacement.

5.3.3.1.4 *Distribution Switches*

This is a small group of assets; the major switching assets on LPDL's distribution system are overhead gang-operated switches and pad-mounted switchgear. Distribution switches are inspected on a six-year cycle and maintained and monitored regularly. Regular maintenance such as cleaning and lubricating adds to system O&M costs but extends the life of the switches to reduce system renewal spending. Switches which have deteriorated beyond maintenance capabilities are replaced.

5.3.3.1.5 *Cables/Conductors*

About 72% of LPDL's system is overhead. Overhead conductors typically outlive the poles that carry them and may be replaced when the pole line is rebuilt. The conductor will be replaced if it improves system losses or the conductor condition is deteriorated; however, LPDL has some older #4 copper and ACSR conductors, which are more prone to breakage during severe weather. Overhead conductors are inspected on a six-year cycle to manage this risk. During line patrols, conductors are assessed for signs of corrosion, broken strands, abrasions, annealing, and elongation. There are no maintenance programs for overhead conductors.

Underground cables are monitored for failure and replaced proactively based on age or when a failure occurs.

5.3.3.2 Description of Maintenance and Inspection Practices

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

5.3.3.2.1 *Maintenance Planning Criteria and Assumptions*

LPDL's maintenance and inspection programs have been carefully selected and are carried out such that current service levels will continue to be maintained to balance customer requirements, price/reliability trade-offs, and industry best practices. LPDL's inspection cycles are based on

Distribution System Code, and TUL assumption is based on Kinectrics' *Asset Depreciation Study for the Ontario Energy Board.*

5.3.3.2.2 *Inspection and Maintenance Programs*

The purpose of this program is to document the requirements for the maintenance or inspection of all key distribution system assets. Each distribution system asset has its own program and within each program a procedure is identified as to how the maintenance and inspection will be performed. The procedure identifies the specific asset and assigns responsibility for the delivery of the program. This procedure is reviewed annually and is subject to the continuous improvement process.

LPDL's inspection and maintenance programs for each asset are summarized in Table 5.3-33**Error! Reference source not found.**. Inspection cycles are based on the *Distribution System Code*.

Table 5.3-33: Summary of inspection and maintenance programs for each asset

Asset	Inspection Programs	Maintenance Programs
Substations	Monthly substation inspection Annual oil tests for substation transformers and tap changers	Routine Station maintenance-6-year cycle (all electrical connections, switches & protective devices, insulating devices)
Polemounted Transformers	Overhead distribution plant inspection-Inspected every 6 years	None
Padmounted Transformers	Underground distribution plant inspection-Inspected every 6 years	Some maintenance as required (vegetation control, connection cleaning and tightening)
Poles	Inspected every 6 years Wood pole integrity tests	None
Gang-Operated Switches	Inspected every 6 years	Regular maintenance (cleaning, lubricating)
Padmounted Switchgear	Inspected every 6 years	Regular maintenance (cleaning and adjusting)
Underground Cables	Terminations inspected every 6 years (at pad-mounted equipment and riser poles)	None
Overhead Conductors	Inspected every 6 years	None

5.3.3.2.3 *Substation Maintenance Program*

The purpose of the Substation Maintenance Program is to identify any issues and remediate them as quickly as possible to ensure continuous operation of each substation and to eliminate any danger to the public. This program consists of monthly inspections, annual oil analysis of all substation power transformers, and routine station maintenance. Hydraulic and Electronic Reclosers will be maintained as part of station maintenance.

The monthly inspection program identifies any deficiencies and verifies that the substation is not going to pose any safety concerns to the public. Each station has a specific checklist which is to be completed and signed off by the inspector.

Oil tests on substation transformers have been proven effective in identifying internal transformer issues before major faults occur which reduce reliability and increase cost. LPDL performs both oil quality and gas-in-oil tests at least once per year. Additional oil tests are completed upon recommendations by the service firm providing the analysis and as required.

LPDL adopts routine station maintenance as well. In order to ensure the reliability of each station the station is taken off line and maintained at regular intervals. This will provide the opportunity to check all electrical connections, inspect the equipment condition, perform tests if necessary, inspect and clean all insulating devices, switches and protective devices. Maintenance activities will occur at approximately seven (7) year intervals. For each station a "Distribution Station Maintenance" form will be completed.

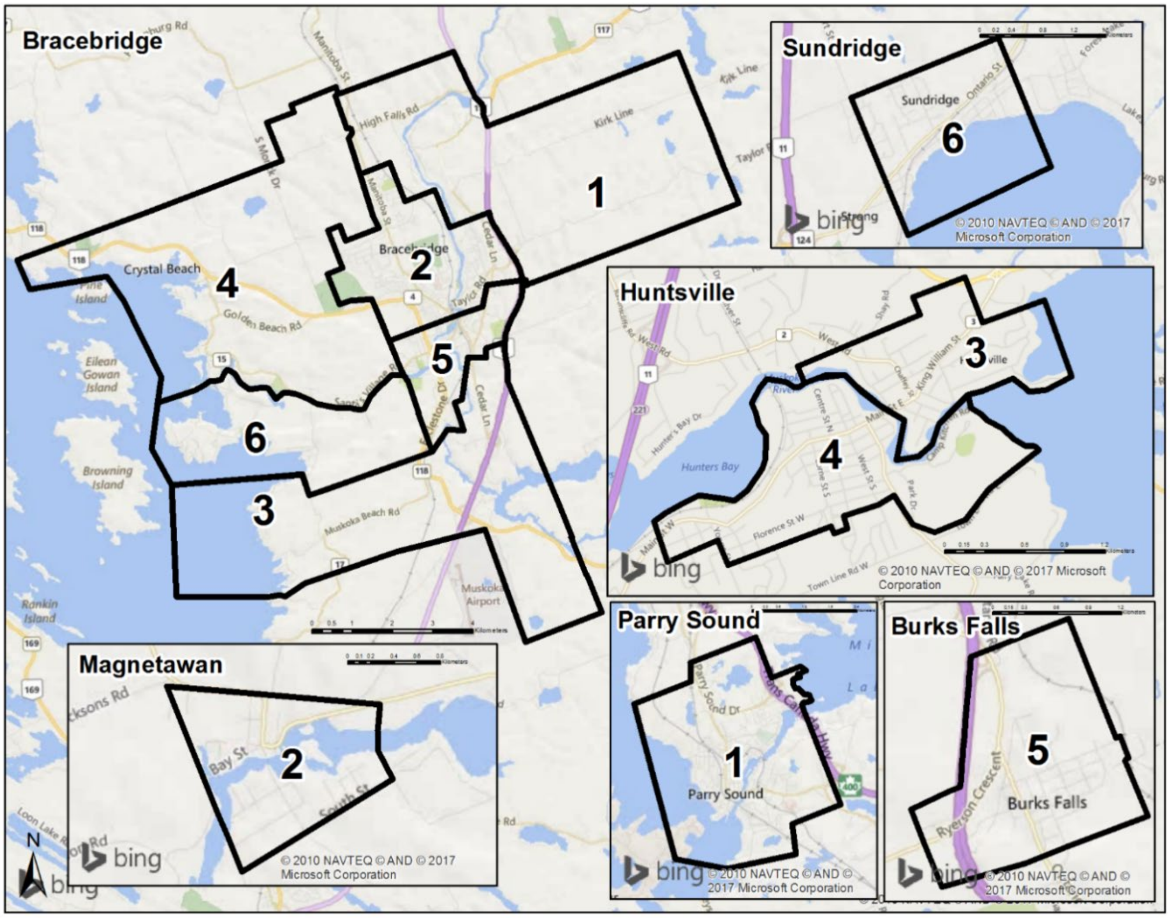
5.3.3.2.4 *Line Clearing and Tree Trimming Maintenance Program*

The purpose of this program is to clear all lines from the encroachment of trees and branches to eliminate, as best as possible, tree contact with lines. LPDL has many areas in its service territory with mature trees. This program is a major contributor to maintaining reliability and directly impacts customer satisfaction. Based on outage occurrences, LPDL experiences fewer tree contact outages during and immediately after trimming. This program is organized on a six-year rotating cycle (each year completing one zone). Figure 5.3-40: Map of Inspection and Trimming Zones shows the six inspection and trimming zones.

Over the next few years, LPDL will continue looking into the outage data to evaluate the feasibility of trimming more often in some zones, or specifically high forested areas that require more attention. As with all changes to existing processes, this analysis will be done with full attention to the budget, balancing customer priorities of reliability with that of affordability.

All trees, limbs and branches shall be trimmed in accordance with LPDL's Specifications for Tree Trimming. In locations where it would be considered inappropriate to trim to such clearances then the Contractor will consult with and obtain approval from LPDL for alternate clearances.

Figure 5.3-40: Map of Inspection and Trimming Zones



5.3.3.2.5 *Distribution System Plant Inspections and Ground Level Maintenance*

Distribution System Plant Inspections are regulated under the OEB *Distribution System Code*. LPDL will conduct system plant inspections on a six-year cycle.

This program is organized on a six-year rotating cycle completing one zone each year as shown below:

- Zone 1- Bracebridge & Parry Sound -2027
- Zone 2- Bracebridge & Magnetawan- 2028
- Zone 3-Bracebridge & Huntsville /north of river- 2025
- Zone 4- Bracebridge & Huntsville/ south of river- 2024
- Zone 5-Bracebridge & Burk's Falls- 2029
- Zone 6-Bracebridge & Sundridge- 2026

The specific tasks to be completed under this program are detailed below. The work involves a visit to each asset location. For overhead distribution plant this means every pole and for underground distribution plant this means all pad mounted equipment.

- Visual Inspection

  The visual inspection is to be completed by meeting the minimum requirements of the *Distribution System Code*. LPDL's condition of the assets will be documented by completing all required Inspection form(s).

- Wood Pole Integrity Tests

  Wood pole integrity tests are performed on poles where the strength of the pole is questionable. The pole is hammer tested (hit with a hammer to test wood density or hollow sounding). The wood boring technique is used as needed by the testers (wood boring (1/2" bit) the pole at or just below grade where most of the decay occurs) to determine the condition.

  LPDL also has a third-party vendor to perform non-destructive testing on poles of critical feeders.

- Ground Level Repair of Defects

  This program identifies items in the field which will require replacement, repair, or alteration. The inspector may make any of the following repairs as required while on site:

  - Replace guy guard
  - Cut unused anchors below grade and replace backfill
  - Install molding over exposed down ground
  - Drive exposed ground rods to below grade
  - Replace ground rod clamp – remake down ground connection, test ground rod resistance
  - Bore pole, record, and report findings

5.3.3.2.6 *Thermography Inspection Program*

Infrared thermography has proven to be an excellent tool to identify poor electrical connections and overloaded equipment on the distribution system. The purpose of the Thermography Inspection Program is to identify any issues and remediate them as quickly as possible to ensure continuous operation of the distribution system. This program consists of scheduled overhead and underground inspections of the distribution system.

5.3.3.2.7 *Switch Maintenance Program*

The purpose of the Switch Maintenance Program is to ensure the continued reliability of all switching devices in the electrical distribution system. The goal of the program is to maintain all switches on a six-year rotational basis. This program consists of physically cleaning, lubricating, and ensuring the switch operates smoothly. This program applies to 3-phase gang operated switches only (pole and pad-mounted).

LPDL overhead switches will be maintained and inspected following the guidelines set out by the manufacturer.

Pad mounted switching cubicles will be inspected and/or maintained if required in each year of a six-year cycle. LPDL pad-mounted switches will be maintained and inspected following the guidelines set out by the manufacture.

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

5.3.3.3.1 *Forecasting*

A distributor should explain the processes and tools it uses to forecast, prioritize, and optimize system renewal spending and how a distributor intends to operate within budget envelopes.

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 carried out by Barkley Technology Inc. to establish the risk ratings of distribution assets in service. By considering all relevant information related to the assets' operating condition, the condition of all infrastructure assets was assessed and assigned an Asset Risk (age and condition based) and Overall Risk (based on age, condition, and various risk factors). Resulting information from the ACA study was used to help forecast the renewal needs of LPDL's assets over the forecast period. Additional details on the inputs and processes used to forecast System Renewal spending are included in sections 5.3.1.2 and 5.3.1.3 of this DSP.

5.3.3.3.2 *Prioritization & Optimization*

For prioritizing capital expenditures, a distributor should help the audience understand the approaches the distributor uses to balance a customer's need for reliability and capital expenditure costs.

As outlined in section 5.3.1.3, discretionary System Renewal projects are selected based on risk and value assessments. Project costs are estimated using distribution system data. By evaluating these risks, we prioritize projects that mitigate higher risks first, while deferring lower-risk projects that can be managed more cost-effectively.

Prioritized investments are paced according to available funding and resource requirements for implementation. Asset performance is managed through LPDL's capital investments and maintenance programs. Inspections, maintenance, and testing help extend asset life and identify those in the worst condition for replacement. Data from asset databases, maintenance records, and outages are essential for optimizing project value.

5.3.3.3.3 *Strategies for Operating within Budget Envelopes*

The proposed System Renewal projects over the forecast period have been identified to maintain system reliability and are paced for implementation based on the available funding for asset renewal, taking into account the resources required for the specific type of work involved. Utilizing LPDL's AM process, assets have been prioritized for renewal or rehabilitation over the next five years.

Given that LPDL's AM process is continuously updated with new information, annual investment planning is conducted to inform any necessary budget adjustments for the subsequent year. LPDL recognizes that circumstances may change, and if required, budgets can be re-prioritized based on customer and system needs. For instance, due to the non-discretionary nature of System Access projects, these will take precedence if there are competing demands with System Renewal projects. This annual investment planning ensures that LPDL employs the best available information to effectively plan and manage the highest priority projects and programs over the forecast period, while adhering to the approved budget envelopes.

5.3.3.3.4 *Risks of Proceeding / Not Proceeding*

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

Risk is a fundamental consideration in the selection and prioritization of capital expenditures. During the prioritization process, the potential risks associated with proceeding or not proceeding with each capital expenditure are meticulously evaluated. This assessment determines whether a capital expenditure is necessary within the forecast period or can be deferred to a later date.

High-priority assets are subject to monitoring, and detailed plans are developed to either maintain, refurbish, or replace these assets to mitigate associated risks. It is important to note that certain assets inherently carry higher risks than others. For instance, power transformers at stations have a greater nominal risk level compared to pole-mounted transformers. Assets exhibiting a low risk rating combined with high consequence risk are prioritized for replacement, whereas those with a low risk rating but lower consequence are allocated a lower replacement priority.

The top projects within each category are identified through this prioritization process and undergo further investigation and expert analysis to ensure data accuracy and determine the appropriate scope of work.

5.3.3.3.5 *Consideration of Future Capacity Requirements*

> *A distributor should also be able to demonstrate that in planning the lifecycle of an asset, it has considered the future capacity requirements of the asset such that it does not need to be replaced prematurely due to capacity constraints.*

LPDL carefully evaluates future load requirements across all six municipalities. Utilizing the CYME software, we model our feeders to identify potential areas necessitating upgrades. During all project design phases, whether it be capital or maintenance, future capacity needs are carefully considered. For instance, when replacing poles, we may opt to install taller poles to accommodate the addition of an extra feeder in anticipation of future demand.

Moreover, LPDL's relatively compact team structure facilitates seamless communication and effective coordination with developers and municipal authorities.

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

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

LPDL has implemented an ACA as per the recommendations of the OEB. This comprehensive evaluation process enables LPDL to systematically assess the condition and performance of its assets, thereby ensuring informed decision-making regarding maintenance and replacements. Additionally, LPDL utilizes ESRI-based geospatial software in consultation with Barkley Technology Inc. to enhance the accuracy of its asset management and planning activities. This technological integration allows for precise mapping, tracking, and analysis of the distribution network, ultimately supporting the reliability and efficiency of LPDL's operations.

5.3.4 System Capability Assessment for REG & DERs

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

LPDL has no restricted feeders to connect REGs & DERs. LPDL does not have any forecasted costs within the DSP timeframe to accommodate the connection of any REG or DER connections.

5.3.5 CDM Activities to Address System Needs

The OEB's 2021 Conservation and Demand Management Guidelines for Electricity Distributors (the CDM Guidelines)16 provide updated OEB guidance on the role of conservation and demand management (CDM) for rate-regulated electricity distributors, taking into account the provincial 2021-2024 CDM Framework and previous provincial CDM frameworks, and addressing the treatment of CDM activities in distribution rates. The CDM Guidelines require distributors to make reasonable efforts to incorporate CDM activities into their distribution system planning process, by considering whether distribution rate-funded CDM activities may be a preferred approach to meeting a system need, thus avoiding or deferring spending on traditional infrastructure. CDM activities potentially eligible for *distribution rate funding are not limited to energy efficiency programs and include activities that reduce instantaneous electricity demand, including demand response and energy storage.*[17]

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

Distributors may apply to the OEB for funding through distribution rates for CDM activities as specified in the CDM Guidelines. Any application for CDM funding to address system needs must include a consideration of the projected effects on the distribution system on a long-term basis and the forecast expenditures. Distributors must explain the proposed activity in the context of the distributor's DSP, including providing details on the system need that is being addressed, any infrastructure investments that are being avoided or deferred as a result of the CDM activity (could include investments upstream of a distributor), and the prioritization of the proposed CDM activity relative to other system investments in the DSP. Distributors should describe their approach to assessing the benefits and costs of CDM activity. However, the CDM Guidelines recognize that the Framework for Energy Innovation's (FEI) near-term activities include defining an approach to assessing the benefits and costs of distributed energy resources and may apply approaches from the FEI in the future.

LPDL evaluates CDM during its planning to see if it can replace any planned investments, but no viable CDM options have been found so far. Consequently, no CDM activities are scheduled for the forecast period. LPDL will keep considering distribution rate funded CDM to possibly delay or avoid investments.

LPDL is aware of and closely following activity relating to the letter sent from the Minister of Energy to the IESO on February 9, 2024 regarding Conservation and Demand Management Programs. Information to date indicates that the LDC marketing or delivery of CDM programs will be fully funded, and as such does not impact this DSP.

5.4 Capital Expenditure Plan

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

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

This section summarizes LPDL's capital expenditure plan, which has been developed to meet LPDL's strategic corporate objectives. The capital expenditure plan was developed based on the planning and AM processes previously described in Section 5.3.

5.4.1 Capital Expenditure Summary

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

The distributor must provide completed appendices 2-AA – Capital Projects Table and 2-AB – Capital Expenditure Summary Table along with the following information about a distributor's capital expenditures.

The capital expenditure summary provides a snapshot of LPDL's capital and System O&M expenditures over the 2019–2029 DSP period. For summary purposes, the entire capital costs of individual projects and programs have been allocated to one of the four OEB investment categories based on the primary driver for the investment:

1. System Access.
2. System Renewal.
3. System Service.
4. General Plant.

The breakdown of plan versus actuals over the historical period, broken down by category, is provided in Table 5.4-34 and the forecast costs broken down by category are provided in Table 5.4-35.

Table 5.4-34: Historical Capital Expenditures and System O&M

Category	Historical														
	2019			2020			2021			2022			2023		
	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.	Plan.	Act.	Var.
	$ '000		%	$ '000		%	$ '000		%	$ '000		%	$ '000		%
System Access															
Gross Capital Spend	380	1,449	281%	450	1,392	209%	500	2,728	446%	550	2,126	287%	750	2,388	218%
Capital Contributions	250	902	261%	250	769	208%	300	2,139	613%	300	1,779	493%	500	1,979	296%
Net Capital Expenditures	130	547	321%	200	623	212%	200	589	195%	250	347	39%	250	409	64%
System Renewal															
Gross Capital Spend	1,110	1,254	13%	1,360	408	-70%	1,385	920	-34%	880	1,326	51%	1,225	1,416	16%
Capital Contributions	-	-	0%	-	-	0%	-	-	0%	-	-	0%	-	-	0%
Net Capital Expenditures	1,110	1,254	13%	1,360	408	-70%	1,385	920	-34%	880	1,326	51%	1,225	1,416	16%
System Service															
Gross Capital Spend	485	410	-15%	710	194	-73%	515	239	-54%	880	288	-67%	780	506	-35%
Capital Contributions	-	-	0%	-	-	0%	-	-	0%	-	-	0%	-	-	0%
Net Capital Expenditures	485	410	- 0	710	194	- 1	515	239	- 1	880	288	- 1	780	506	- 0
General Plant															
Gross Capital Spend	650	360	-45%	385	347	-10%	425	640	51%	740	633	-14%	613	691	13%
Capital Contributions	-	-	0%	-	-	0%	-	-	0%	-	-	0%	-	-	0%
Net Capital Expenditures	650	360	- 0	385	347	- 0	425	640	1	740	633	- 0	613	691	0
Total Expenditures, Gross	2,625	3,473	32%	2,905	2,341	-19%	2,825	4,527	60%	3,050	4,373	43%	3,368	5,001	48%
Total Capital Contribution	250	902	261%	250	769	208%	300	2,139	613%	300	1,779	493%	500	1,979	296%
Total Expenditures, Net	2,375	2,571	8%	2,655	1,572	-41%	2,525	2,388	-5%	2,750	2,594	-6%	2,868	3,022	5%
System O&M	1,834	1,711	-7%	1,890	2,132	13%	2,123	2,043	-4%	2,016	2,438	21%	2,510	2,452	-2%

Table 5.4-35: Forecast Capital Expenditures and System O&M

Category	Forecast				
	2025	2026	2027	2028	2029
	$ '000	$ '000	$ '000	$ '000	$ '000
System Access					
Gross Capital Spend	1,130	1,035	1,040	1,045	1,045
Capital Contributions	800	600	600	600	600
Net Capital Expenditures	330	435	440	445	445
System Renewal					
Gross Capital Spend	1,335	1,300	850	1,210	1,280
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	1,335	1,300	850	1,210	1,280
System Service					
Gross Capital Spend	775	1,755	3,105	810	860
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	775	1,755	3,105	810	860
General Plant					
Gross Capital Spend	1,030	485	565	565	475
Capital Contributions	-	-	-	-	-
Net Capital Expenditures	1,030	485	565	565	475
Total Expenditures, Gross	4,270	4,575	5,560	3,630	3,660
Total Capital Contribution	800	600	600	600	600
Total Expenditures, Net	3,470	3,975	4,960	3,030	3,060
System O&M	2,811	2,952	3,099	3,254	3,417

5.4.1.1 Plan vs Actual Variances for the Historical Period

An analysis of a distributor's capital expenditure performance for the DSP's historical period. This should include an explanation of variances by investment or category, including that of actuals versus the OEB-approved/planned amounts for the applicant's last OEB-approved Cost of Service or Custom IR application and DSP (the variance analysis should also include variances in planned and actual volume of work completed). A distributor should particularly explain variances in a given year that are much higher or lower than the historical trend.

Comparing the historical DSP costs with the actual and bridge expenditures highlights the necessary adjustments LPDL had to implement in response to evolving customer needs, modifications in the scope of work, and other constraints such as inclement weather, pandemic or operational restrictions. This comparison serves to shed light on the dynamic nature of project management within LPDL and underscores the importance of flexibility and adaptability in achieving project goals.

Assessing and understanding these variances is a critical component of LPDL's commitment to continuous improvement in its estimation and budgeting processes. Additionally, variance analysis plays a pivotal role in refining LPDL's forecasting models and improving the accuracy of future projections. By closely examining the factors contributing to deviations between planned and actual expenditures, LPDL can identify patterns and implement corrective measures to mitigate similar issues in future projects. This iterative process of evaluation and adjustment is essential for optimizing capital investments and enhancing the overall efficiency of the organization.

Any significant variances that exceed LPDL's materiality threshold of $50,000 are analyzed and explained in the following subsections. This detailed analysis not only enhances transparency but also informs future planning and resource allocation decisions, ensuring that LPDL remains agile and responsive to both expected and unforeseen challenges.

The following tables summarize variances in capital expenditure by category.

Table 5.4-36: Variance Explanations - 2019 Planned Versus Actuals

Category	2019 Plan. ($ '000)	2019 Act. ($ '000)	2019 Var. ($ '000)	Variance Explanation
System Access, Net	130	547	417	LPDL spent significantly more on metering because the majority of Lakeland's metering system was due for reverification (Intitial 2009 smart-meter roll out). Higher-than-expected number of projects for new customer connections. In addition, two new subdivision developments were ongoing.
System Renewal, Net	1,110	1,254	144	LPDL expeditied an underground renewal project, Catherine Cres, to facilitate connection of a new subdivision to its 27.6kV sytem. The alternative was connect the subdivision to HONI-owned 12.47kV feeders, which would have resulted in less visibility and greater long-term costs.
System Service, Net	485	410	- 75	In order to reduce budget to meet System Access requirements, LPDL did not invest in any new SCADA technologies in 2019.
General Plant, Net	650	360	-290	In order to reduce budget to meet System Access requirements, LPDL deferred planned enhancements to software and cybersecurity.
Total Expenditures, Net	2,375	2,571	196	Increase in overall spend was due to the increase in System Access.
Capital Contribution	250	902	652	LPDL experienced significantly more customer and Telecom (bell) driven work than originally budgeted, which lead to significantly more capital contributions as well.
Total Expenditures, Gross	2,625	3,473	848	See explanations above
System O&M	1,834	1,711	-123	LPDL's O&M in 2019 was lower than normal due to significantly lower than typical storm damage.

Table 5.4-37: Variance Explanations - 2020 Planned Versus Actuals

Category	2020 Plan. ($ '000)	2020 Act. ($ '000)	2020 Var. ($ '000)	Variance Explanation
System Access, Net	200	623	423	Significantly higher-than-expected number of projects for new customer connections. LPDL invested $306,000 in the Speedier Micro-grid and battery-backup project.
System Renewal, Net	1,360	408	- 952	Numerous projects were delayed due to the Covid-19 pandemic, ultimately leading to significantly less spending by year-end.
System Service, Net	710	194	- 516	Numerous projects were delayed due to the Covid-19 pandemic, ultimately leading to significantly less spending by year-end.
General Plant, Net	385	347	- 38	N/A
Total Expenditures, Net	2,655	1,572	-1,083	The overall System Renewal and System Servicve expenditures were significantly lower due to the Covid-19 pandemic.
Capital Contribution	250	769	519	LPDL experienced significantly more customer driven work than originally budgeted, which lead to significantly more capital contributions as well.
Total Expenditures, Gross	2,905	2,341	- 564	See explanations above
System O&M	1,890	2,132	242	LPDL spent a higher amount than budgeted on meters in 2020 to catch up on 2009 seal reverifications. This work included testing and analysis of all three-phase customer meters. Additionally, LPDL experienced a higher than average year for storm damage with a tornado in June and a severe wind storm in October.

Table 5.4-38: Variance Explanations - 2021 Planned Versus Actuals

Category	2021 Plan. ($ '000)	2021 Act. ($ '000)	2021 Var. ($ '000)	Variance Explanation
System Access, Net	200	589	389	Significantly higher-than-expected number of projects for new customer connections. Bell's FTTH project in Parry Sound began in 2021, which was unforeseen while budgeting. $95K was recoverable in relation to our “renewable generation” submission to the OEB in 2019, Generation plant upgrades 2012, that we were approved for recovery this year. The $95,093 is the leftover that was not approved for recovery, so according to the APH/OEB we needed to reclassify that amount to capital.
System Renewal, Net	1,385	920	- 465	In order to reduce budget to meet System Access and General Plant requirements, LPDL deferred some System Renewal projects.
System Service, Net	515	239	- 276	In order to reduce budget to meet System Access and General Plant requirements, LPDL deferred some System Service projects.
General Plant, Net	425	640	215	LPDL purchased a new Digger truck as the existing truck was in urgent need of replacement. Some funds were deferred from System Service, computer software and cybersecurity.
Total Expenditures, Net	2,525	2,388	- 137	See explanations above
Capital Contribution	300	2,139	1,839	Capital Contribution was sigificantly higher than expected due to an increase in new customer builds and Bell's FTTH project in Parry Sound.
Total Expenditures, Gross	2,825	4,527	1,702	See explanations above
System O&M	2,123	2,043	- 80	LPDL spent less on meters than predicted, partially because of the amount spent in 2020. Small reductions in O&M can also partially be explained by the ongoing pandemic "waves", where LPDL made efforts to separate personnel.

Table 5.4-39: Variance Explanations - 2022 Planned Versus Actuals

Category	2022			Variance Explanation
	Plan.	Act.	Var.	
	$ '000			
System Access, Net	250	347	97	Higher-than-expected number of projects for new customer connections. Bell's FTTH project in Parry Sound finished in 2022; focus shifted to Bracebridge.
System Renewal, Net	880	1,326	446	LPDL undertook many projects which it felt were necessary for the safety and reliability of the system. Several severely leaning poles were found on Edward St. Poles on Muskoka Beach Rd. were found to be in very poor condition, carrying a 44kV circuit. In addition, LPDL replaced more poles in need of immediate replacement than normal, such as poles found with severe rot or woodpecker holes. Pole replacements due to trouble calls and storms were also higher than budgeted.
System Service, Net	880	288	- 592	System Service expenditures were reduced to account for higher System Access and System Renewal spending. Areas that were reduced included Self Healing Components - SCADA, and a feeder tie build in Huntsville.
General Plant, Net	740	633	- 107	A portion of the new digger truck was budgeted for 2022 (the chassis, 132K), but the full cost was paid in 2021.
Total Expenditures, Net	2,750	2,594	- 156	See explanations above
Capital Contribution	300	1,779	1,479	Capital Contribution was sigificantly higher than expected due to an increase in new customer builds and Bell's FTTH projects in Parry Sound and Bracebridge.
Total Expenditures, Gross	3,050	4,373	1,323	See explanations above
System O&M	2,016	2,438	422	LPDL's increase in expenditures was caused by a large increase in disconnect/reconnect requests, increased cost of underground locates, ongoing porcelain switch changes, and preventative maintenance identified by infrared scanning. In addition, LPDL suffered two major storms. In October, heavy snow followed by warm weather caused heavy accumulation and sticking to trees, causing sag into lines and limb breakage. In December, Muskoka saw one of the most intense snow storms in decades, which saw at least 180cm of snowfall over two days.

Table 5.4-40: Variance Explanations - 2023 Planned Versus Actuals

Category	2023 Plan. ($ '000)	2023 Act. ($ '000)	2023 Var. ($ '000)	Variance Explanation
System Access, Net	250	409	159	Higher-than-expected number of projects for new customer connections. Bell's FTTH project in Bracebridge was significant.
System Renewal, Net	1,225	1,416	191	During station maintenance at Parry Sound MS1, PCB contaminated oil was discovered in the switching building in the transformers and capacitor bank. LPDL took the opportunity to remove old infrastructure, including the switch house which also had asbestos. LPDL installed two new padmounted viper reclosers and upgraded the protections, while removing all abandoned towering and buildings.
System Service, Net	780	506	- 274	The decrease in System Service was to account for additiona expenditures in System Renewal and System Access.
General Plant, Net	613	691	78	The difference in expenditure is due to LPDL's substation communication and battery backup systems, which began late 2022 and continued into 2023.
Total Expenditures, Net	2,868	3,022	154	See explanations above
Capital Contribution	500	1,979	1,479	Capital Contribution was sigificantly higher than expected due to an increase in new customer builds and Bell's FTTH project continuation in Bracebridge.
Total Expenditures, Gross	3,368	5,001	1,633	See explanations above
System O&M	2,510	2,452	- 58	LPDL experienced no major storms in 2023.

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

5.4.1.2 Forecast Expenditures

An analysis of a distributor's capital expenditures for the DSP's forecast period. For capital investments that have a project life cycle greater than one year, the proposed accounting treatment, including the treatment of the cost of funds for construction work-in-progress.

Outlined below is a summary of LPDL's planned capital expenditures by year and investment category over the forecast period. The tables are organized to account for the inclusion and exclusion of the construction of the new 27.6kV substation.

Table 5.4-41: Forecast Capital Expenditure by Investment Category (Incl. New Substation)

Category	Forecast					Total	Percentage of Total
	2025	2026	2027	2028	2029		
	$ '000						
System Access, Net	330	435	440	445	445	2,095	11%
System Renewal, Net	1,335	1,300	850	1,210	1,280	5,975	32%
System Service, Net	775	1,755	3,105	810	860	7,305	39%
General Plant, Net	1,030	485	565	565	475	3,120	17%
Total Expenditures, Net	3,470	3,975	4,960	3,030	3,060	18,495	100%

Table 5.4-42: Forecast Capital Expenditure by Investment Category (Excl. New Substation)

Category	Forecast					Total	Percentage of Total
	2025	2026	2027	2028	2029		
	$ '000						
System Access, Net	330	435	440	445	445	2,095	14%
System Renewal, Net	1,335	1,300	850	1,210	1,280	5,975	39%
System Service, Net	775	755	1,105	810	860	4,305	28%
General Plant, Net	1,030	485	565	565	475	3,120	20%
Total Expenditures, Net	3,470	2,975	2,960	3,030	3,060	15,495	100%

When including costs from the planned 27.6kV substation, System Service is the largest capital expenditure over the 2025–2029 forecast period representing 39% of overall spending.

5.4.1.2.1 *System Access*

Expenditures in this category are driven by external requirements such as servicing new customer loads and relocating distribution plants to suit road authorities. The timing of investment is driven by the needs of the external parties. These expenditures are mandatory. Specific project scopes are rarely known at the time that the budget is set, and total expenditures can vary from year to year. Most of the forecasted investments in this category are based on historical requirements and known upcoming subdivision developments. Specific projects such as relocations are budgeted based on LPDL's estimates and historical averages, in conjunction with information from the municipalities and developers about the work required over the project life cycle. LPDL's proposed 2025 – 2029 System Access forecast investments are found in Table 5.4-43 and Figure 5.4-41 below.

New Connection expenses are based on historical information. Section 5.4.1.3.1.1 details how the forecast numbers were adjusted based on trends that were skewed during COVID.

Customer Un-Contributed Capital remains the highest percentage of System Access, as aging infrastructure is upgraded to support customer-requested projects. This might include LPDL absorbing part of the cost of replacing poles supplying a new service connection / subdivision, determined after thorough economic analysis.

Material Investment Narrative *Meters* provides more detailed information on that line item.

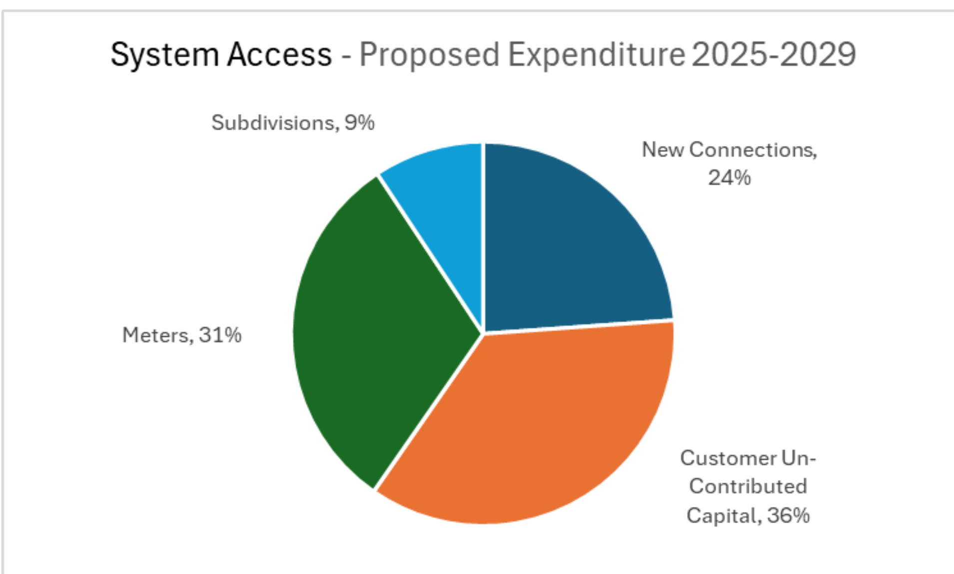
(1) Installation of residential and commercial meters at new service locations; LPDL is expecting to purchase 500 new meters on average each year over the forecast period.
(2) Upgrade of wholesale metering installations for expanded service requirements; Between 2024 and 2028, approximately 12,600 of LPDL's meters will expire and need resealing.
(3) Replacement of failed metering, expired seals, and obsolete metering for residential. LPDL expects to replace 250 meters over the forecast period, equivalent to what was replaced between 2020 and 2024.
2025 expenditures on meters is forecast lower than the remainder of the forecast period as vendor lead times have necessitated more on-hand. These supply chain issues are being resolved for 2025.

Subdivisions already on the horizon for 2025-2029 include Mattamy Phase 11, Woodward Street Subdivision (Madison Homes), Gainsborough Subdivision (Loon Call), Winnifred Street Subdivision, and Maple Street Subdivision.

Table 5.4-43: Forecast Net System Access Expenditures

Category	Forecast ($'000)						Percentage of Total
	2025	2026	2027	2028	2029	Total	
New Connections	100	100	100	100	100	500	24%
Customer Un-Contributed Capital	150	150	150	150	150	750	36%
Meters	50	150	150	150	150	650	31%
Subdivisions	30	35	40	45	45	195	9%
Total Expenditure, Net	330	435	440	445	445	2,095	100%

Figure 5.4-41: Forecast Net System Access Expenditures



5.4.1.2.2 *System Renewal*

Expenditures within the System Renewal category are predominantly influenced by the condition of distribution system assets and are crucial for ensuring the overall reliability, safety, and sustainability of the distribution network. As outlined in Section 5.3.1, one of the key inputs for determining system renewal projects is the ACA results. These results provide a foundational basis for LPDL to identify necessary investments over the DSP period.

By the end of 2025, the completion of all 4.16kV infrastructure in Bracebridge will result in a significant reduction in 4.16kV conversion expenditures under the System Renewal category post-2025.

Generally, assets identified as being in poor or very poor condition are prioritized for investment consideration. However, this does not imply that all assets in these categories are automatically included in the investment plan. As previously mentioned, various other factors are also taken into account, with an aim to achieve levelized and sustainable investments in these areas. The budget in this category is distributed evenly across the years, based on historical expenses.

Expenditures in the Trouble Call Capital category are predominantly reactive, addressing unforeseen events such as broken poles, cable failures, and other emergency repairs necessary to maintain the integrity of the distribution network. These investments are critical for ensuring the prompt restoration of services and mitigating the impact of unexpected disruptions on customers.

Underground Renewal expenditures in the forecast period include Westvale in 2025 as well as a larger project in Meadow Heights in 2028 and 2029. These replacements address results from the ACA showing asset conditions requiring replacement.

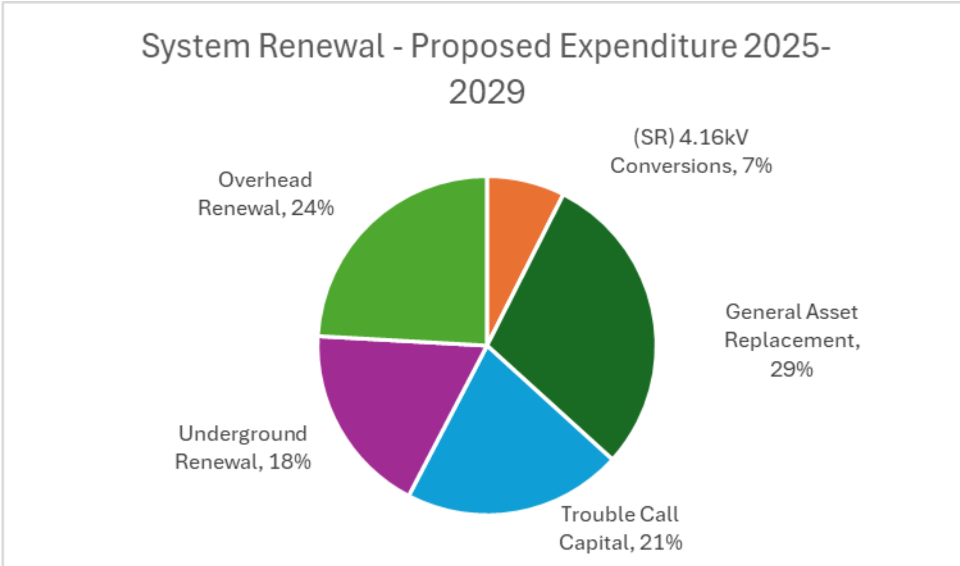
Additionally, LPDL will strategically reduce overhead renewal expenditures in 2025 to prioritize and support the completion of 4.16kV conversions, aligning with our broader system renewal objectives and enhancing the overall reliability and capacity of the network. This will result in an increased budget in 2026 to remain on top of renewal of poles, conductors etc. returning to a more levelized forecast in 2027 through 2029.

Forecasted investments in System Renewal are detailed in the following table.

Table 5.4-44: Forecast Net System Renewal Expenditures

Category	Forecast ($'000)						Percentage of Total
	2025	2026	2027	2028	2029	Total	
(SR) 4.16kV Conversions	445	0	0	0	0	445	7%
General Asset Replacement	350	350	350	350	350	1750	29%
Trouble Call Capital	250	250	250	250	250	1250	21%
Underground Renewal	290	0	0	420	380	1090	18%
Overhead Renewal	0	700	250	190	300	1440	24%
Total Expenditure, Net	1,335	1,300	850	1,210	1,280	5,975	100%

Figure 5.4-42: Forecast Net System Renewal Expenditures



5.4.1.2.3 *System Service*

System Service investments entail strategic modifications to LPDL's distribution infrastructure to ensure it meets the company's operational objectives, such as system efficiency, DER integration, and grid flexibility. Furthermore, these investments are essential for addressing anticipated future customer electricity service requirements. Effective planning for future growth is critical, as it allows LPDL to proactively manage increasing demand and ensure the robustness of the distribution network. Investments in System Service are detailed in the following Tables and Figures and in Section 5.4.1.3.1.3.

In 2025, LPDL's SCADA upgrade is taking priority, and then SCADA costs are lower for the next few years. In 2025, grid automation projects include reclosers in Magnetawan and at MS5 in Parry Sound, as well as restringing at Isabella Street in Parry Sound. This will result in improved communications with remote areas of the grid and increase reliability.

Miscellaneous Asset Upgrades in 2025 includes primary fuse replacement at all stations / substations. The budget figures are based on quotes obtained for the fuse replacement project. Proactive station /line lightning arrestor replacement is also planned, and the costs are based on historical figures extrapolated to current economics.

Project details for 4.16kV Conversions are discussed in the project narrative. Apart from the new substation, this is the largest budget item over the forecast period.

LPDL's most significant investment involves the building of a new substation in Bracebridge to replace the existing 4.16kV substation, Bracebridge MS3. The new station will increase LPDL's ability to switch load throughout the system for regular planned operations and maintenance activities as well as responding to outages. Currently, the Bracebridge MS3 substation does not have sufficient backup supply. The new 27.6kV substation will also increase the capacity LPDL will need to service new growth load, as well as load growth associated with electrification. Material Investment Narrative *SS – New 27.6kV Substation* provides further details.

Capacity Upgrades starting in 2025 include Isabella St, and Beatty St. both in Parry Sound. These are expected to complete in 2026 and 2027. These investments are aligned with LPDL customer priorities. The Material Investment Narrative *SS-Capacity Upgrades* provides details on these projects.

System Redundancy projects are forecast for 2027, giving LPDL the ability to shift load to another feeder during an outage event to reduce the number of customers impacted. This directly affects SAIDI and SAIFI scores. The project details…

Table 5.4-45: Forecast Net System Service Expenditures (Incl. New Substation)

Category	Forecast ($'000)						Percentage of Total
	2025	2026	2027	2028	2029	Total	
SCADA/Grid Automation	266	70	70	250	250	906	12%
Misc Asset Upgrades	69	120	120	120	120	549	8%
4.16kV Conversions	0	375	390	440	490	1695	23%
New 27.6kV Substation	0	1000	2000	0	0	3000	41%
Capacity Upgrades	440	190	145	0	0	775	11%
System Redundancy	0	0	380	0	0	380	5%
Total Expenditure, Net	775	1,755	3,105	810	860	7,305	100%

Figure 5.4-43: Forecast Net System Service Expenditures (Incl. New Substation)

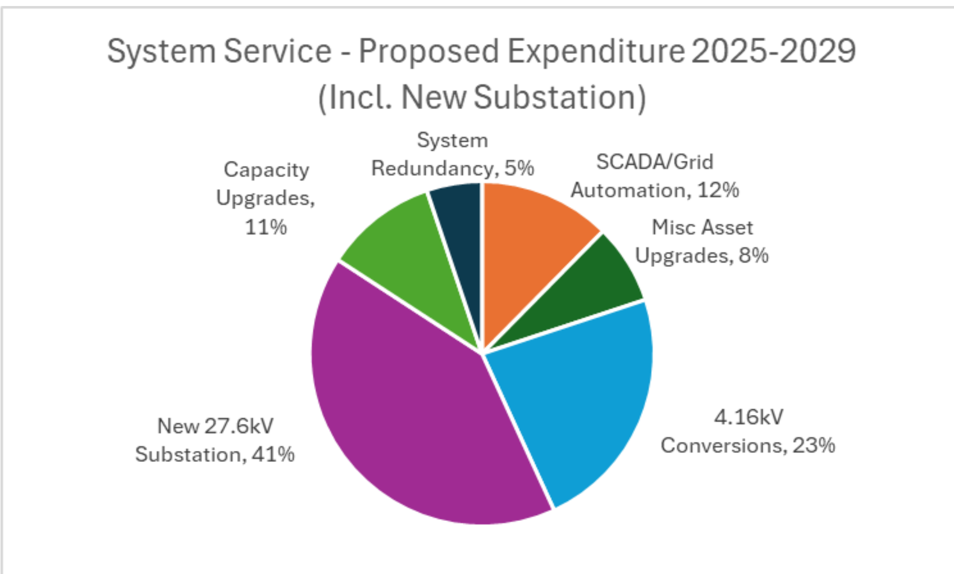
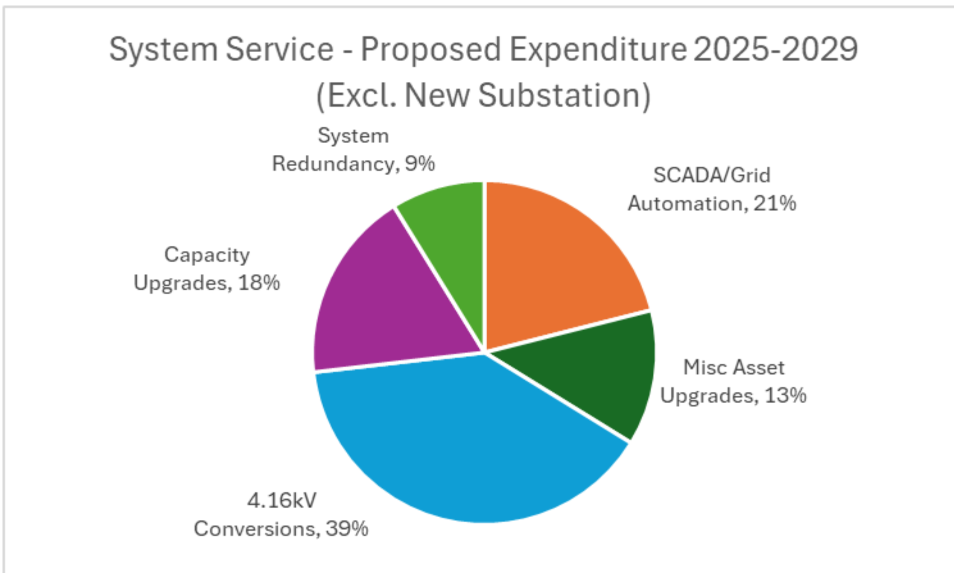


Table 5.4-46: Forecast Net System Service Expenditures (Excl. New Substation)

Category	Forecast ($'000)						Percentage of Total
	2025	2026	2027	2028	2029	Total	
SCADA/Grid Automation	266	70	70	250	250	906	21%
Misc Asset Upgrades	69	120	120	120	120	549	13%
4.16kV Conversions	0	375	390	440	490	1695	39%
Capacity Upgrades	440	190	145	0	0	775	18%
System Redundancy	0	0	380	0	0	380	9%
Total Expenditure, Net	775	755	1,105	810	860	4,305	100%

Figure 5.4-44: Forecast Net System Service Expenditures (Excl. New Substation)



5.4.1.2.4 GENERAL PLANT

Expenditures in the General Plant category are driven by the necessity to modify, replace, or augment assets that are not part of the distribution system but are essential to supporting LPDL's 24/7 operations. These investments are critical for ensuring the safe and reliable operation of the distribution network. Neglecting or deprioritizing General Plant investments could lead to significant operational risks, including increased costs and disruptions in the future.

LPDL tracks the age, usage, and ongoing maintenance costs of fleet vehicles when considering replacement. LPDL projects that we will need to replace some fleet vehicles throughout the forecast period, including one small bucket truck and dump truck. The cost of vehicles has increased significantly since the previous DSP and is reflected in the budget.

Failing to maintain and upgrade the fleet of vehicles and equipment used for field operations can pose substantial risks. Aging or poorly maintained fleet assets can result in higher breakdown rates, increased downtime, and greater maintenance costs. This can compromise the efficiency and reliability of service delivery, leading to customer dissatisfaction and potential safety hazards. Therefore, it is imperative to allocate sufficient resources to General Plant investments, as captured in the table below.

Transportation Equipment costs are significant at 63% of the General Plant forecast budget. This reflects the deferred bucket truck purchase outlined in Section 5.4.1.3.1.4. Subsequent years' investments are based on the Fleet Management Plan, which is adjusted annually to accommodate rising vehicle costs.

Computer Software costs reflect an upgrade to the Geographic Information System in 2025 and ongoing updates in subsequent years, resulting in a total of 14% of the forecast budget for General Plant.

Buildings – Distribution expenses include xx in 2026.

Computer Hardware includes necessary costs for laptops and tablets used by all departments. This is a small portion of the total General Plant budget at 2%.

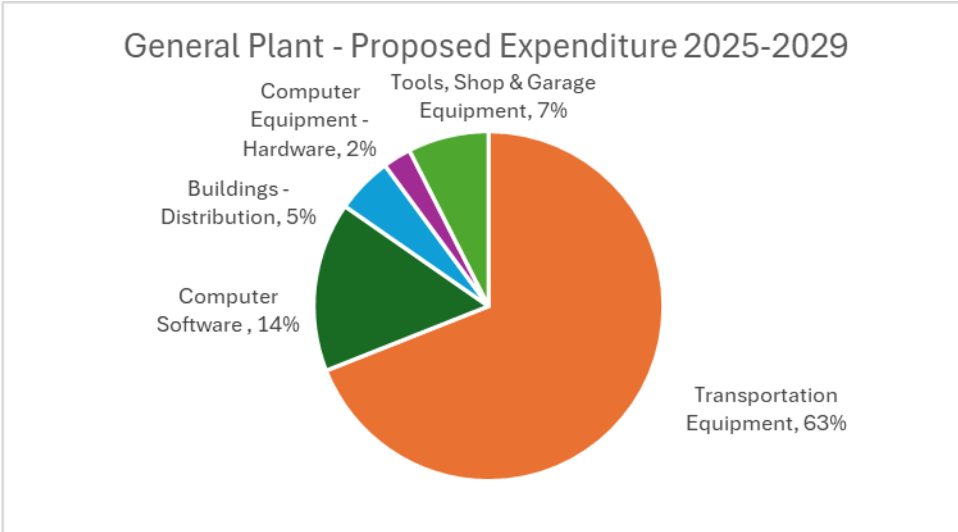
Tools, Shop and Garage Equipment includes replacing damaged hand tools and equipment and consumable items necessary for the maintenance and repair of the system. This is 7% of the budget.

Cybersecurity expenses are higher in 2025 for new firewalls, backup servers and assessment tools, with continuing budget for maintenance and upgrades through the remainder of the forecast period. See Material Investment Narrative *GP-Cybersecurity* for details on this project. Overall, these costs are 8% of the budget.

Table 5.4-47: Forecast Net General Plant Expenditures

Category	Forecast ($'000)						Percentage of Total
	2025	2026	2027	2028	2029	Total	
Transportation Equipment	730	150	400	400	300	1980	63%
Computer Software	150	75	75	75	75	450	14%
Buildings - Distribution	0	150	0	0	0	150	5%
Computer Equipment - Hardware	15	15	15	15	15	75	2%
Tools, Shop & Garage Equipment	35	45	45	45	45	215	7%
Cybersecurity	100	50	30	30	40	250	8%
Total Expenditure, Net	1,030	485	565	565	475	3,120	100%

Figure 5.4-45: Forecast Net General Plant Expenditures



5.4.1.2.5 *Investments with Project Lifecycle Greater than One Year*

LPDL has three projects which will see expenditures over two years:

1. 2025-2026: Isabella St, New Poles & Primary Conductor
2. 2026-2027: New 27.6kV Substation
3. 2028-2029: Meadow Heights Underground Renewal

These projects are detailed in the subsections below.

5.4.1.2.6 *2025-2026: Isabella St, New Poles & Primary Conductor*

In collaboration with developers, municipal authorities, EVSE installers, and the school board, LPDL has identified a significant growth area in Parry Sound that will experience a substantial increase in new load demand. The current overhead conductor is undersized and requires upgrading to accommodate this anticipated growth.

5.4.1.2.7 *2026-2027: New 27.6kV Substation*

Given the extensive scope and complexity involved in dismantling the existing substation and installing a new one on the same parcel, the project is anticipated to span two years.

5.4.1.2.8 *Meadow Heights Underground Renewal*

Due to the size of the Meadow Heights underground renewal project, LPDL will complete the project over two years.

5.4.1.3 Comparison of Forecast and Historical Expenditures

An analysis of capital expenditures in the DSP's forecast period compared to the historical period.

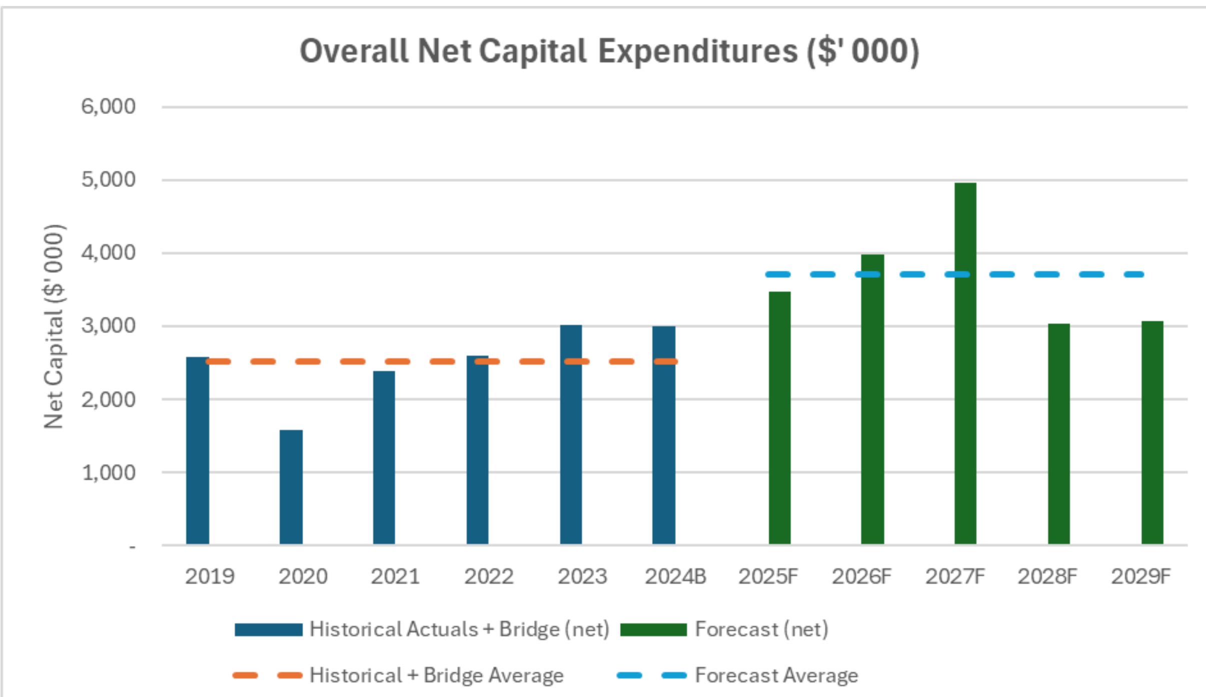
The following subsections present a comparison of LPDL's capital expenditures during the DSP's forecast period with those in the historical period.

5.4.1.3.1 *Overall Capital Expenditures*

LPDL forecasts its overall capital expenditures to remain relatively stable over the forecast period when compared to the historical period, with the exception of the significant investment required for the new 27.6kV substation project. This particular project entails complex procedures, including the dismantling of the existing substation and the installation of a new one on the same site, which is expected to span two years due to its extensive scope. In addition, the Covid-19 pandemic caused a significant drop in capital expenditures in 2020.

Other expenditures are projected to increase incrementally each year, primarily driven by rising operational costs, including those associated with labor, materials, and vehicles. This gradual cost escalation reflects the ongoing need to maintain and upgrade infrastructure to meet growing demand and ensure reliable service delivery. Figure 5.4-46 represents the overall net capital expenditures from 2019-2029.

Figure 5.4-46: Overall Net Capital Expenditures



5.4.1.3.1.1 System Access

LPDL had a higher than forecasted system access expenditure over the historical period. This is mainly due to an increase in new customers. LPDL had several ongoing subdivision developments with each lot being purchased and built early on. LPDL also had Bell FTTH projects ongoing during the historical period, however the majority of the expenditure was contributed by Bell.

System access is a non-discretionary category that has historically shown some degree of variability. LPDL forecasts a mild decrease in customer growth in the forecast period when compared to the historical period.

LPDL also predicts the number of service upgrades to slightly slow at a similar rate. In the 2020-2023 years, there was a significant increase in the number of customers investing in service upgrades, however a steady decrease has already been observed by the second half of 2024.

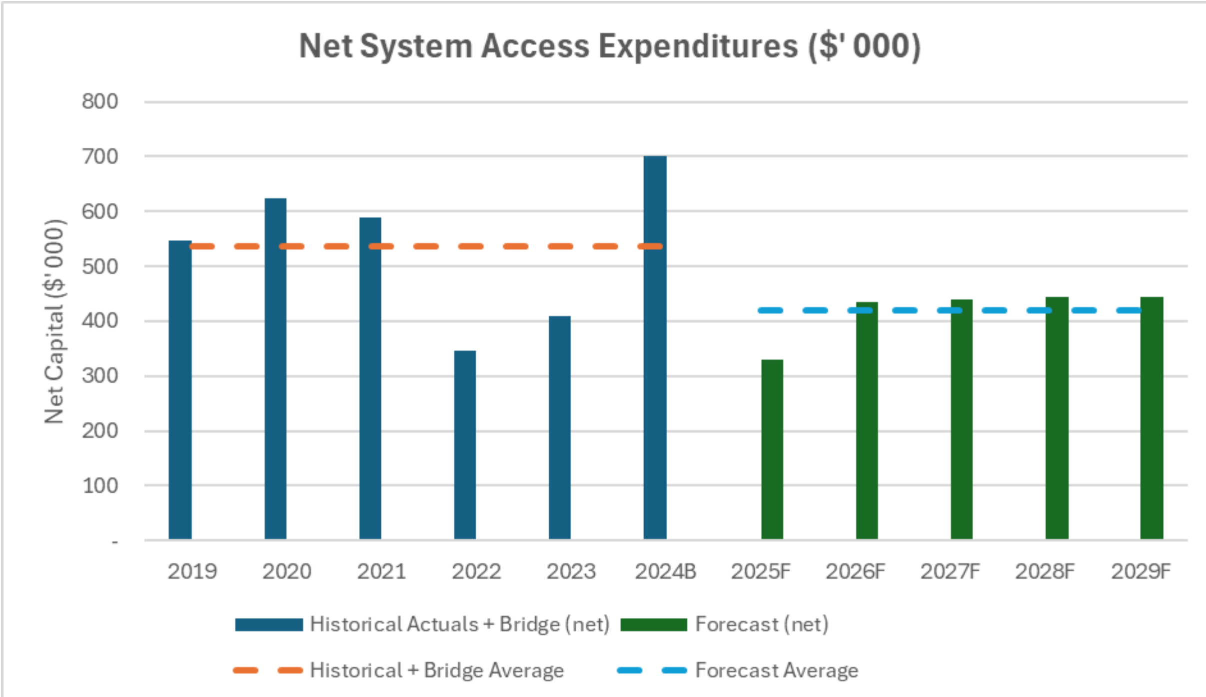
LPDL experienced higher-than-forecasted system access expenditures during the forecast period, primarily driven by an unexpected surge in new customer connections. This uptick was fueled by multiple ongoing subdivision developments, with each lot being rapidly sold and constructed. Additionally, Bell FTTH projects contributed significantly to the expenditures during the historical period, however the majority of the investment was contributed by Bell.

System access is categorized as non-discretionary and has historically exhibited a degree of unpredictability. LPDL projects a modest decline in customer growth during the forecast period compared to the historical period. This is anticipated to result in a corresponding decrease in system access expenditures.

Furthermore, LPDL anticipates a slight deceleration in the demand for service upgrades. The years 2020-2023 saw a notable increase in customers opting for service upgrades, likely driven by heightened consumer investment in home improvements during the pandemic. However, by the second half of 2024, a discernible slowdown in this trend has already been observed, indicating a return to more typical levels of upgrade activity.

Figure 5.4-47 represents the net system access expenditures from 2019-2029.

Figure 5.4-47: Net System Access Expenditures



5.4.1.3.1.2 System Renewal

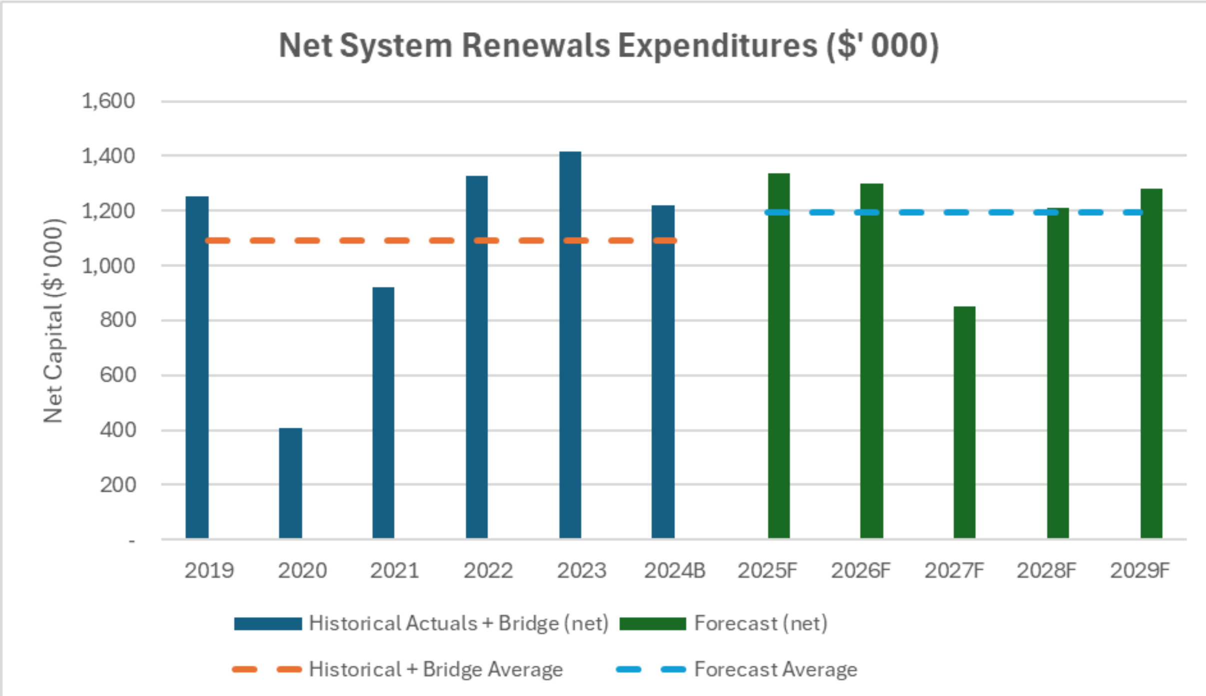
LPDL is forecasting an average increase of 10% in system renewal expenditures during the forecast period when compared to the historical period. However, excluding system renewal expenditures in 2020, which were very low due to the pandemic, the forecasted expenditure actually shows a slight decrease of approximately 3%.

Despite these projections, the overall costs of infrastructure projects have risen and are expected to remain elevated throughout the forecast period. The primary factor behind this surge is the substantial increase in material costs, encompassing transformers, poles, and various hardware components. Additionally, LPDL must address an increasingly aging infrastructure as shown by the Very Poor categories in Figure 5.3-21, necessitating prioritized investment in system renewals to adhere to our ACA and to fulfill our safety and reliability objectives.

Therefore, it is imperative for LPDL to continue investing in System Renewal projects, while also balancing other investment requirements, such as the MS3 27.6kV substation in 2027. These investments are essential not only to maintain system integrity but also to ensure compliance with regulatory requirements and to meet customer priorities of maintaining the overall reliability and safety of our electricity distribution network.

Figure 5.4-48 represents the net system renewal expenditures from 2019-2029.

Figure 5.4-48: Net System Renewals Expenditures



5.4.1.3.1.3 System Service

The forecasted average for System Service expenditures is projected to be 311% higher than the historical plus bridge year average, as illustrated in Figure 5.4-49. When excluding the new 27.6kV substation, the forecasted System Service expenditures are anticipated to be 142% higher than the historical averages, as depicted in Figure 5.4-50.

A significant factor contributing to this increase is LPDL's historical categorization of voltage conversion work in Bracebridge under System Renewal. However, starting in 2026, the voltage conversions in Parry Sound are more appropriately aligned with System Service activities. This realignment is driven primarily by the need for capacity and cost reduction over the long term, with asset condition being a secondary consideration.

To mitigate some of the increased costs, LPDL has reduced its planned expenditures in Distribution Automation/SCADA for the years 2026 and 2027. This adjustment aims to balance the budget while still addressing critical infrastructure needs and maintaining compliance with regulatory requirements.

Figure 5.4-49 represents the net system service expenditures from 2019-2029 when including the new 27.6kV substation.

Figure 5.4-49: Net System Service Expenditures Incl. New 27.6kV Substation

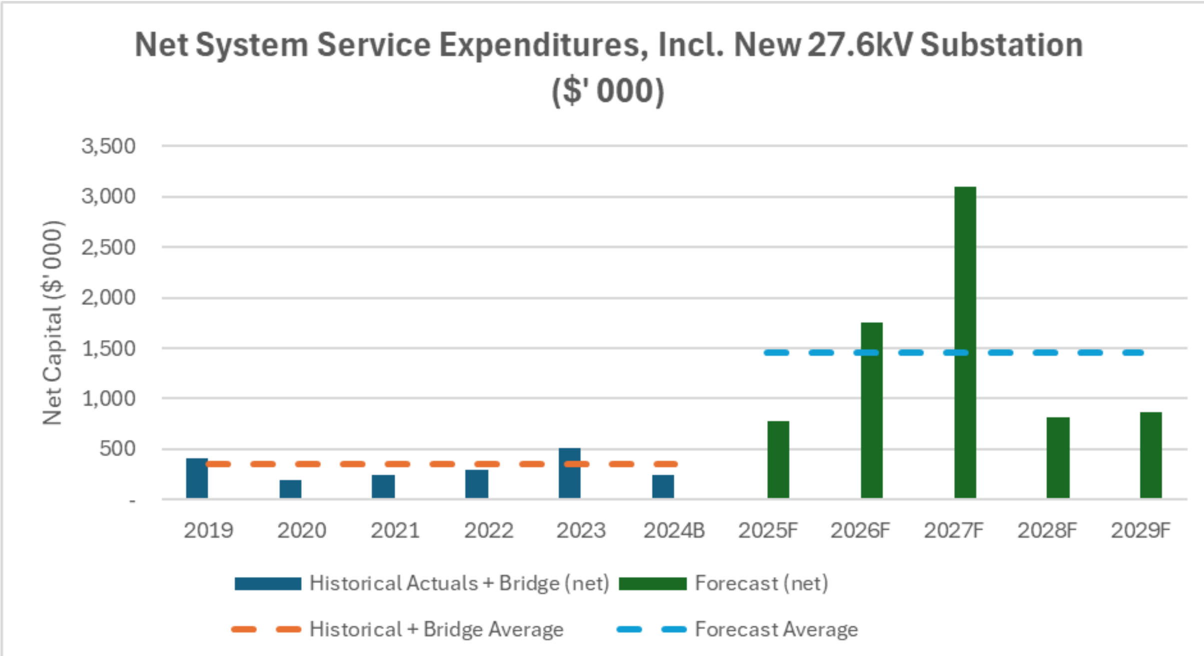
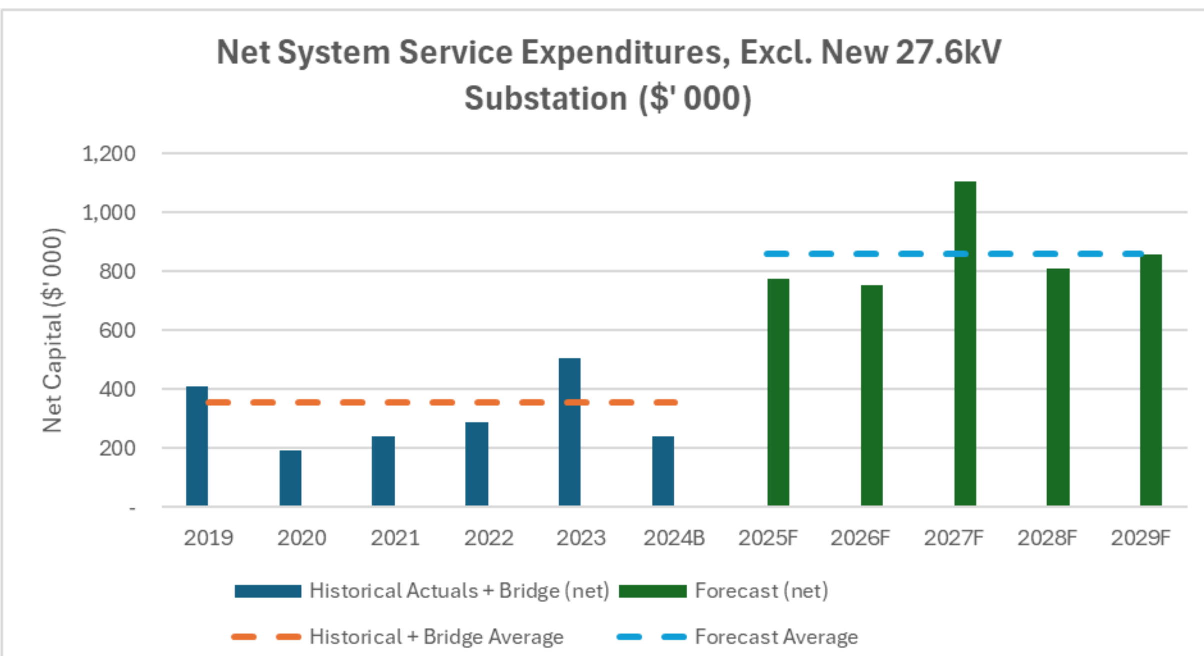


Figure 5.4-50 represents the net system service expenditures from 2019-2029 when excluding the new 27.6kV substation.

Figure 5.4-50: Net System Service Expenditures Excl. New 27.6kV Substation



5.4.1.3.1.4 General Plant

LPDL forecasts an average increase of 6% in General Plant expenditures when compared to historical expenditures. Due to vehicle supply chain constraints in 2021 and 2022, a new double bucket truck was pre-ordered. A portion of the truck's cost has been paid, with the remainder outstanding, resulting in a cost spike in 2025.

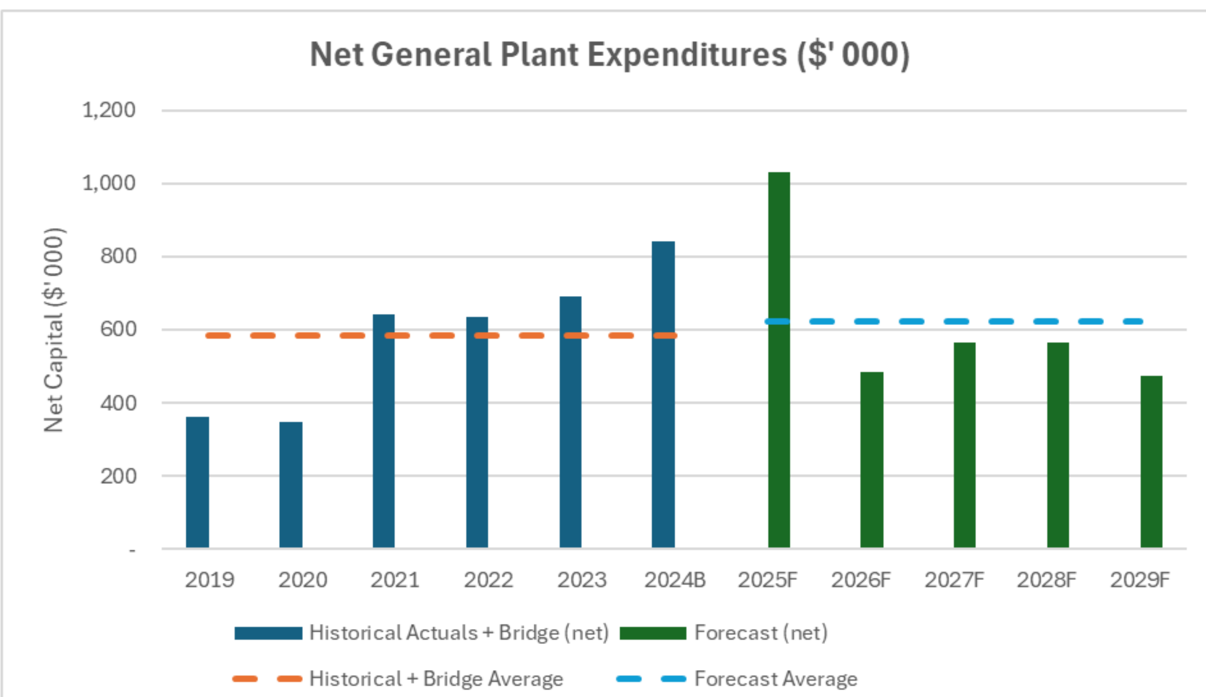
The overall cost of vehicles has increased over the historical period. Replacements are scheduled for a small bucket truck, a dump truck, and several smaller trucks throughout the forecast period. However, final replacement decisions will depend on several variables, such as ongoing maintenance costs and vehicle mileage. If a vehicle performs well without major breakdowns, its replacement may be deferred.

LPDL is also investing in advanced cybersecurity measures, deemed highly critical for maintaining operations and customer data integrity. These investments include the installation of upgraded firewalls at substations, the deployment of immutable backup servers—designed to be tamper-proof unlike conventional backup solutions—and a network vulnerability assessment tool. Justification for these cybersecurity expenditures also encompasses requirements from our insurance provider, which has highlighted these measures as top priorities.

In summary, LPDL's General Plant expenditures reflect a strategic approach to balancing necessary vehicle replacements and enhancing cybersecurity infrastructure. These efforts aim to ensure robust operational capabilities and compliance with evolving industry standards.

Figure 5.4-51 represents the net general plant expenditures from 2019-2029.

Figure 5.4-51: Net General Plant Expenditures



5.4.1.4 IMPORTANT MODIFICATIONS TO CAPITAL PROGRAMS SINCE LAST DSP

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

5.4.1.4.1 *NEW 27.6KV SUBSTATION*

In the previous DSP, it was proposed that the existing transformer at Golden Beach MS be relocated to the Bracebridge MS3 site for the new 27.6kV substation. While this relocation initially appeared to be a viable solution, it fails to support the new initiatives for electrification and DER connections. LPDL has now deemed it crucial to its reliability and capacity to establish a fourth 27.6kV substation. This addition is anticipated to significantly enhance customer satisfaction and operational efficiency.

Moreover, proceeding with the relocation plan would have introduced an unacceptable level of risk, particularly in the event of a failure of any one of our 27.6kV transformers. During peak summer periods, operational constraints are exacerbated when relying on only two of the three existing 27.6kV systems, a situation that will worsen with the increasing 4.16kV load transfer and the growing capacity demands of our customers. The new transformer order, therefore, is essential not only for meeting current load requirements but also for providing the necessary infrastructure to support future growth and maintain service reliability.

5.4.1.4.2 *DISTRIBUTION AUTOMATION / SCADA*

LPDL has significantly increased its investment in Distribution Automation and SCADA systems since the previous DSP. This includes the deployment of advanced smart switches, specifically viper reclosers managed by Schweitzer Engineering Laboratories (SEL) 651R relays. These enhancements facilitate real-time monitoring and control of the distribution network, improving fault detection, isolation, and restoration processes. Additionally, the integration of these advanced devices supports predictive maintenance and improves overall system reliability and efficiency.

5.4.1.5 FORECAST IMPACT OF SYSTEM INVESTMENTS ON SYSTEM O&M COSTS

System O&M costs are also shown to reflect the potential impact, if any, of capital expenditures on routine system O&M. A distributor is expected to consider the reduction in O&M costs when planning capital investments. A description of the impacts of capital expenditures on O&M must be given for each year, or a statement that the capital plans did not impact O&M costs. A distributor must consider the trade-offs between capital and O&M when assessing alternative options to a capital investment.

LPDL's forecast O&M expenditure is summarized in the table below.

Table 5.4-48: LPDL Forecast O&M

Category	Forecast ($ '000)				
	2025	2026	2027	2028	2029
System O&M	2,811	2,952	3,099	3,254	3,417

LPDL expects the impact of capital investments on O&M costs to vary by project. Proactive O&M expenses like inspections, infrared testing, and tree trimming are not expected to change, as they are long-standing practices. Specific projects, such as pole-line rebuilds, focus on replacing outdated or poor-condition assets, reducing higher reactive O&M costs. Additionally, System Access projects may lower future O&M costs by upgrading distribution systems during customer-initiated projects, thus reducing unplanned power interruptions.

5.4.1.6 Non-Distribution Activities

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

LPDL has not included any expenditures for non-distribution activities in its budget.

5.4.2 Justifying Capital Expenditures

As indicated in Chapter 1, the onus is on a distributor to provide the data, information and analyses necessary to support the capital-related costs upon which the distributor's rate proposal is based. Filings must enable the OEB to assess whether and how a distributor's DSP delivers value to customers, including by controlling costs in relation to its proposed investments through appropriate identification, optimization, prioritization, pacing of capital-related expenditures, and how it developed its overall capital budget envelope.
A distributor should also keep pace with technological changes and integrate cost-effective innovative investments and traditional planning needs such as load growth, asset condition and reliability.

A distributor must not only provide information to justify each individual investment, but also the total amount of its proposed capital expenditures. A distributor should provide context on how its overall capital expenditures over the next five years, as a whole, will achieve the distributor's objectives. Particularly, a distributor should comment on lumpy investment years and rate impacts of capital investments in the long-term.

Delivering value to customers and other stakeholders is LPDL's highest priority, as highlighted by LPDL's mission and vision statements:

LPDL's mission statement is "to distribute electricity safely and reliably to customers in Bracebridge, Burk's Falls, Huntsville, Magnetawan, Parry Sound and Sundridge. We are accountable to these towns that also are our shareholders. Our objective is to be one of Ontario's top performing distribution companies in both customer service and reliability."

LPDL's vision is to strive to be an organization that:

- Provides a safe environment for our employees;
- Provides safe, reliable and economic services for our customers;
- Continues to prosper and be a good place to work; and
- Provides a safe environment for and maintains good relations with the general public and suppliers;
- All with consideration of the Environment.

Capital planning is also linked to customer priorities, as identified in Section 5.2.2.1.3.4.

The planning process requires input from various sources such as:

• Load growth forecasts;
• Consultation with customers and third parties;
• Regulatory requirements;
• Asset Condition Assessment (ACA); and
• Potential/planned CDM, REG, DER, and EV connections.

Each of these inputs affects the overall capital plan differently. LPDL follows an iterative process while evaluating the inputs to ensure they accurately reflect the changes that occur during normal business operations.

Key assumptions made in the planning process include the accuracy of historical trends in system access expenditures and how they are used to forecast capital expenditures and the use of historical growth, CDM, DER and EV adoption rates to assist in forecasting future load growth patterns.

The capital plan is developed within the AM process as outlined in Figure 5.3-19. It starts with the needs assessment which defines the project outline. This is assigned to a capital category, and then undergoes technical and financial assessments, including consideration of all alternatives. This draft project is prioritized along with all other projects using the project prioritization matrix, where a value between 0 and 4 is assigned to each weighted criteria to determine the priority value. The specific priority values only determine a project's ranking when compared to other project's total values. The total determines how the project is treated, not what order it will be completed in.

For example, the highest priority item might be a value of 80, while the next highest project is assigned a total value of 79; this means the two projects are treated almost equally: the 79-value project might be scheduled earlier than the higher-value project due to other projects that can be accomplished at the same time, due to financial reasons, or due to customer impacts.

The entire matrix is reviewed to build the proposed capital plan, which is balanced and adjusted for annual financial constraints. This proposed capital plan is sent to the Board for approval, and may receive further minor adjustments during this process. As LPDL executes projects according to the approved plan, evaluating lessons learned and financial metrics helps to identify continuous improvement activities and make adjustments to future planning.

The following subsections discuss the building blocks of the capital plan structure.

5.4.2.1 Customer Value

As noted in Section 5.2.2.1, LPDL frequently interacts with residential, business and municipal customers to share information, educate them, and gather feedback on its services and priorities. Customer needs and expectations are crucial for shaping capital plans. These engagements include town hall meetings, surveys, and direct communication channels, which provide valuable insights into the community's requirements and preferences. By incorporating this feedback, LPDL ensures that its investment strategies not only meet regulatory and operational standards but also align closely with customer expectations, delivering high value and satisfaction.

In addition, LPDL continually monitors industry trends and regulatory developments to adapt its plans proactively. This dynamic approach allows the company to address emerging challenges and opportunities effectively, ensuring that the infrastructure remains robust and capable of supporting future demands. The integration of advanced technologies and sustainable practices further underscores LPDL's commitment to providing reliable, efficient, and environmentally friendly services to its customers.

LPDL's AM objectives, which drive planning and decision making, include prioritizing public and worker safety, system reliability, future capacity considerations, organizational efficiency and productivity, our customer's priorities and preferences, continuous innovation, and environmental sustainability.

As System Access projects are non-discretionary, and deliver high value to customers and shareholders, LPDL places these projects in high priority to ensure that our partners and customer's needs are met. Planning for seasonal construction that drives the timing of projects in this category is essential, both for internal resources and supply chain management. Vendor and customer communications ensure cost effective solutions such as right-sizing of transformers with the option of overhead vs padmount, Discussions also consider innovative long-term solutions for both cost-effectiveness and system reliability. These extensive measures ensure that LPDL's capital expenditure plans are thoroughly justified, strategically sound, and offer enduring benefits to all stakeholders. The plans align to LPDL's mission and vision, as well as customer priorities, while maximizing the benefits of long-term investments.

5.4.2.2 Technological changes and innovations

LPDL is committed to staying at the forefront of technological advancements to ensure both our organization and our customers can leverage the efficiencies and benefits these innovations bring. This commitment to modernization is essential not only for meeting customer expectations for reliability and communication but also for safeguarding their privacy in an increasingly digital world.

GIS: To enhance our capabilities, LPDL is upgrading its GIS from the existing geometric model to the UNM. This upgrade will allow for more accurate mapping and asset management, which in turn supports better decision-making and operational efficiency.

Distribution Automation & SCADA: Further, LPDL continues to make significant investments in Distribution Automation and our SCADA system. These technologies are crucial for remote monitoring and control of the distribution network, leading to improved reliability and faster response times during outages, leading to lower outage duration. This project is detailed in Material Investment Narrative *Distribution Automation/SCADA.*

Outage Management: Recognizing the importance of communication during power outages, LPDL is also enhancing our outage management system. In the historical period (2019-2023) LPDL began implementing near real-time communication capabilities such as Text Power/Utili-assist to keep customers informed about outage statuses and estimated restoration times. Customer surveys have consistently identified outage communication as one of their top five priorities, and we are dedicated to meeting this need.

Cybersecurity: Cybersecurity remains a top priority for LPDL as we work to protect our distribution system from the growing threat of cyber-terrorism. Our ongoing investments in cybersecurity measures are designed to match the scale and sophistication of potential threats, ensuring the integrity and reliability of our services. The project details during the Forecast period is detailed in Material Investment Narrative *Cybersecurity*

Voltage Conversions: LPDL continues to undertake voltage conversions, a critical component of maintaining and improving the efficiency and reliability of our electrical infrastructure. We are also investing in new technologies to support these conversions, which will facilitate the integration of future DER connections, aligning with our long-term sustainability goals. This project is detailed in Material Investment Narrative *SR&SA-Voltage Conversions.*

Realized Efficiencies due to Smart Meters: LPDL is able to assist with growth planning by utilizing smart meter data where no existing recording devices exist. Customers gain value by having more transparent access to their usage data. In addition, smart meters are able to notify LPDL of concerning conditions such as tampering and high voltage. This project is detailed in Material Investment Narrative *Meters*

By embracing these technological advancements, LPDL not only addresses current challenges but also positions itself to meet future demands, ensuring a robust, efficient, and secure electricity distribution network for all stakeholders.

5.4.2.3 Consideration of Traditional Planning Needs

We consider budget and cost mitigation in all steps of planning, as affordable electricity rates is our customer's top concern, as shown in the customer priorities listing (Section 5.2.2.1.3.4). We balance this with our objectives and obligations including safe and reliable supply of electricity.

Growth, asset condition, and reliability are the primary considerations in LPDL's strategic planning. Maintenance and inspection are considered vital steps in effective planning and spending, as they help identify and address potential issues before they escalate into significant problems. Assets that receive poor and very poor overall risk ratings are prioritized due to their greater system risk and potential impact on customers in the event of a failure. LPDL strives to maintain current or enhanced system performance across the entire network.

Load studies are undertaken to assess current demands and predict future capacity needs, ensuring that the infrastructure can support anticipated growth. Capacity constraints that existed in Parry Sound will be addressed during the Forecast period through Transmission Station upgrades by HONI. Load growth in other communities remain consistent and are not expected to cause constraints or require capital or resource allocation.

In addition to these planning considerations, LPDL also evaluates the broader implications of its projects. This includes the environmental impact of proposed investments, the potential for integrating renewable energy sources, and the opportunities for adopting innovative technologies that can enhance system efficiency and resilience. By taking a holistic approach, LPDL aims to create a robust and sustainable electricity distribution network that meets the present and future needs of its customers.

5.4.2.4 Overall Capital Expenditures

Over the forecast period, LPDL's capital expenditures are meticulously planned to align with the company's overarching goals of delivering safe, reliable, and affordable electricity. This aligns directly with the top two customer priorities. The proposed expenditure levels are strategically balanced to not only maintain but also, where possible, to enhance asset performance, thereby achieving the performance outcomes mandated by the OEB and adhering to LPDL's Asset Management Objectives detailed in Section 5.3.1.1.

Public & Worker Safety play a role in projects such as Trouble Calls Capital under the System Renewal category. Any of the upgrades or asset replacement could affect public safety if the asset is considered prone to fire or lightning damage.

System Reliability & Capacity is evident in all of the System Service and System Renewal projects, from General Asset Replacement to 4.16kV conversions to Underground Renewal.

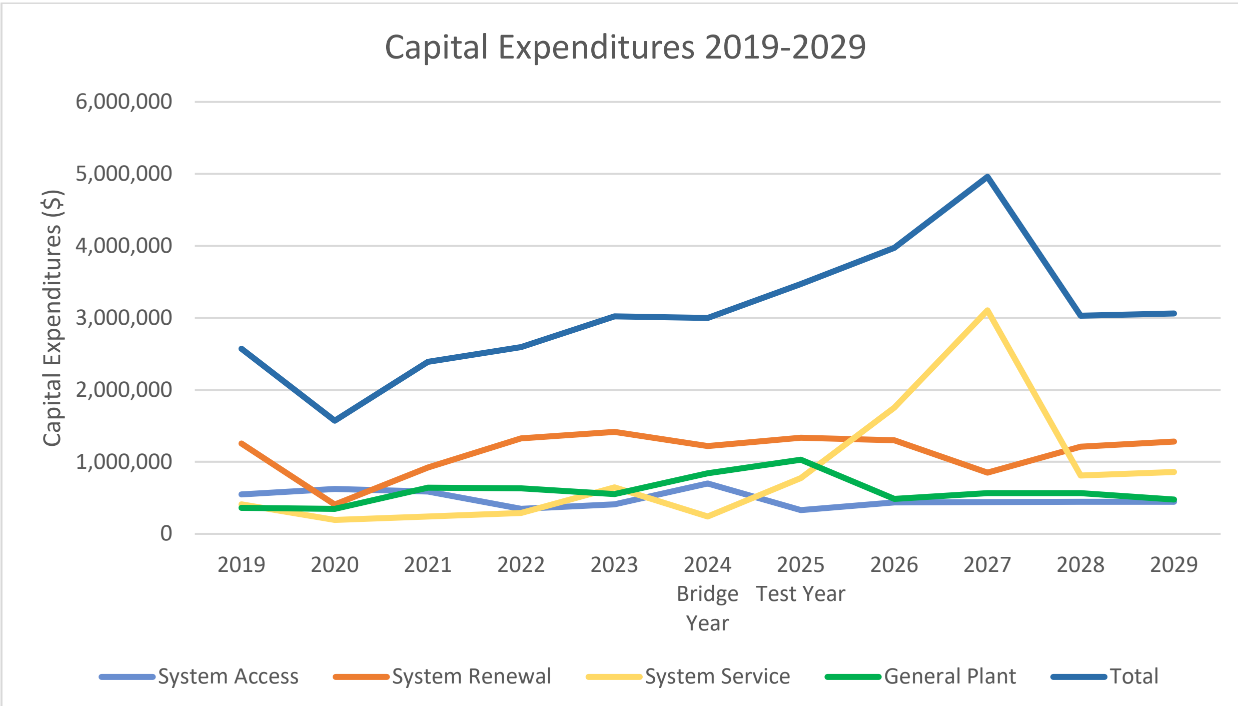
Organizational Efficiency & Productivity is one of the key drivers of the Grid Automation/SCADA project; the others being System Reliability and Innovation

Customer Preference is the outcome that aligns to the System Access projects like New Connections and Subdivisions, and also, since system reliability is a top priority for LPDL's customers, all reliability projects are also customer preference projects.

Innovation is one of the other key drivers for the Grid Automation/SCADA project alongside Organizational Efficiency.

Environmental Sustainability, given the company vision of respecting the natural ecosystems that make up our territory, is a piece of every project LPDL undertakes.

Figure 5.4-52: LPDL Capital Expenditures 2019-2029



Specifically, the increase in overall capital expenditures compared to historical levels is primarily within the System Service category and is driven by the necessity for a new 27.6kV substation, which will be required upon the completion of ongoing 4.16kV voltage conversions. This new substation is critical to support the enhanced voltage levels and the growing demand on the distribution network due to overall societal electrification

Furthermore, as detailed in Section 5.4.1.3, another significant factor contributing to the rise in capital expenditures is the substantial escalation in equipment and material costs since the last DSP. This includes higher prices for all essential components, especially transformers, switchgear, and cabling, which are integral to maintaining the integrity and efficiency of the electrical infrastructure.

As an example, 75 kVA padmount transformer costs have effectively doubled from 2019 to 2024 and 150 kVA padmount transformer costs have gone up by 125%. Poles, as well, have tripled in price from 2019 to 2023.

Table 5.4-49: Example of price increases for padmounted transformers and poles.

Asset	2019	2020	2021	2022	2023	2024	% increase
150 KVA Padmount	$ 13,739				$ 29,151	$ 31,339	128%

50 KVA Polemount	$ 2,525	$ 4,720		$ 3,221	$ 3,510	$ 4,227	67%
75 KVA Padmount	$ 4,637	$ 5,555			$ 8,019	$ 9,183	98%
Wood Poles Class2 45ft.	$ 710	$ 773	$ 1,337	$ 1,648	$ 2,255		217%

5.4.2.5 MATERIAL INVESTMENTS

The focus of this section is on projects/programs that meet the materiality threshold set out in Chapter 2 of the Filing Requirements for Electricity Distribution Rate Applications. However, distributors are encouraged in all instances to consider the applicability of these requirements to ensure that all investments proposed for recovery in rates, including those deemed by the applicant to be distinct for any other reason (e.g., unique characteristics; marked divergence from previous trend) are supported by evidence that enables the OEB's assessment according to the evaluation criteria set out below. The level of detail filed by a distributor to support a given investment project/program should be proportional to the materiality of the investment. The following are guidelines on the information to be provided for any material investment.

For this Application, LPDL's materiality threshold is $50,000. Using the prioritization process previously detailed in Section 5.3.1, LPDL has ranked and prioritized its material investments planned in the Test Year (2025). Table 5.4-50 and Table 5.4-51 present the prioritized list of projects and programs that have been budgeted in 2025 with their associated prioritization scores. Note that the prioritization matrix shows all expenditures including those below the materiality threshold.

Table 5.4-50: Proposed Capital Investments during Test Year

Category	Capital Project	Overall Priority Rating:	2025 Planned Expenditure ($'000)
System Access	New Connections	Mandatory	100
System Access	Customer Un-Contributed Capital		150
System Access	Meters		50
System Access	Subdivisions		30
General Plant	Transportation Equipment	73	730
General Plant	Cybersecurity	70	100
System Service	Capacity Upgrades	64	440
System Renewal	General Asset Replacement	59	350
System Renewal	(SR) 4.16kV Conversions	56	445
System Service	Grid Automation/SCADA	55	266
General Plant	Computer Equipment - Hardware	55	15
System Service	Misc Asset Upgrades	53	69
General Plant	Computer Software	50	150
System Renewal	Trouble Call Capital	48	250
System Renewal	Underground Renewal	45	290
General Plant	Tools, Shop & Garage Equipment	42	35

The first four programs in the table fall in the System Access category and meeting regulatory obligations is the primary driver. These programs form LPDL's primary mission which is to distribute electricity safely and reliably to our customers and are therefore not prioritized against discretionary projects. Four of the next twelve projects belong to the System Renewal category for which system reliability and public safety are the primary drivers. The five projects in the General Plant category are primarily driven by business operation efficiency and non-system physical plant needs. Finally, three System Service projects are those for which the primary driver is improving system reliability and meeting current and future customer demands.

Table 5.4-51: Project Prioritization Matrix

Category	Capital Project	Public & Worker Safety	System Reliability or Capacity	Organizational Efficiency and Productivity	Customer Preference	Innovations	Environmental Concerns	Overall Priority Rating:	2025 Planned Expenditure ($'000)
System Access	New Connections							Mandatory	100
System Access	Customer Un-Contributed Capital								150
System Access	Meters								50
System Access	Subdivisions								30
General Plant	Transportation Equipment	4	4	4	3	2	2	73	730
General Plant	Cybersecurity	4	4	2	4	4	0	70	100
System Service	Capacity Upgrades	2	4	4	4	4	0	64	440
System Renewal	General Asset Replacement	3	3	2	3	0	0	59	350
System Renewal	(SR) 4.16kV Conversions	3	4	3	3	0	0	56	445
System Service	Distribution Automation/SCADA	1	4	4	3	4	0	55	266
General Plant	Computer Equipment - Hardware	1	3	4	4	4	1	55	15
System Service	Misc Asset Upgrades	1	4	4	3	2	1	53	69
General Plant	Computer Software	1	2	4	4	4	1	50	150
System Renewal	Trouble Call Capital	3	2	4	2	0	1	48	250
System Renewal	Underground Renewal	2	3	3	3	0	0	45	290
General Plant	Tools, Shop & Garage Equipment	2	0	4	4	2	1	42	35

For all projects listed in Table 5.4-51, rankings are assigned 0-4 in each category. Below are listed the category value definitions. Category weightings can be found in Table 5.3-21.

Public & Worker Safety (in 5 year period)	***Ranking Value***
No impact to safety	0
Minor injury possible	1
Moderate injury or safety incident is possible	2
Moderate or multiple injury/injuries or safety incident(s) is probable	3
Permanent injury or safety incident would result in serious consequences	4

System Reliability or Capacity	***Ranking Value***
No impact to reliability or capacity	0
Impact to more than 10% of customers	1
Impact to more than 20% of customers	2
Impact to more than 30% of customers.	3
Impact to more than 40% of customers.	4

Organizational Efficiency & Productivity	*Ranking Value*
No impact to Efficiency & Productivity of the System (System Performance)	0
No inefficiencies and Minor impact on System Performance	1
Visible inefficiencies and Moderate impact on System Performance	2
Significant inefficiencies and Major impact on System Performance	3
Extreme inefficiencies and Severe impact on System Performance	4

1

Customer Preference	*Ranking Value*
No impact on Customer Preferences/ Priorities	0
Impact on one(1) of the top five(5) Customer Priorities	1
Impact on one(1) of the top three(3) Customer Priorities	2
Significant impact on two(2) of the top three(3) Customer Priorities	3
Significant impact on all of the top three(3) Customer Priorities.	4

2

Innovation	*Ranking Value*
No Innovation; Existing processes	0
Innovative for LPDL in this project; used elsewhere in LPDL system.	1
Parts of the project are innovative, not all.	2
Innovative for LPDL (brand new); Industry tested but used to demonstrate new process.	3
Innovative for LPDL (brand new); Industry tested with known significant positive impact on system.	4

3

Environmental Sustainability	*Ranking Value*
No impact on Environment; No mitigation of environmental risks.	0
Minor impact on Environment; No mitigation of environmental risks	1
Mitigation provided to one(1) or more environmental risks.	2
Mitigation provided to two(2) or more environmental risks.	3
Mitigation provided to three(3) or more environmental risks.	4

Transportation Equipment, in this case including a bucket truck as well as regular replacement of other vehicles, received a Priority Ranking of 73:

Public and Worker Safety (Weighting 6): Value 4 (Permanent injury or safety incident would result in serious consequences) due to the impact on the safety of employees if fleet assets are aging and experiencing frequent issues or mechanical failures, as well as the safety of customers and the public if response to critical incidents is hampered by fleet concerns.

System Reliability or Capacity (Weighting 5): Value 4 (Impact to more than 40% of customers) is the maximum, assigned in this case because of the impact of an aging fleet on the response to outages or ability to do pro-active system maintenance, repairs or upgrades. Transportation impacts customer requests for service as well.

Operational Efficiency and Productivity (Weighting 3): Value 4 (Extreme inefficiencies and Severe impact on System Performance) due to the vehicles contributing to the ability of lines crews, engineering and metering staff and office workers to get to job sites, meet vendors and carry out day-to-day activities.

Customer Preference (Weighting 3): Value 3 (Significant impact on two(2) of the top three(3) Customer Priorities) due to the need for vehicles to respond to customer requests, outages and safety concerns. Customers in our service area often prefer to see people rather than conduct business virtually.

Innovation (Weighting 2): Value 2 (Parts of the project are innovative, not all.) indicates that the current innovation in transportation, namely electric vehicles, is still not industry standard for larger vehicles, such as bucket trucks, but LPDL is considering EVs with each individual replacement within the Fleet Management Plan.

Environmental Concerns (Weighting 2): Value 2 (Mitigation provided to one(1) or more environmental risks) was assigned to this project as LPDL investigates the development of battery-operated hydraulics so that bucket trucks do not have to idle the truck engine in order to provide power to operate the bucket. This mitigates the impact on the environment.

Multiplying weights times values results in the ranking of 73 for the Transportation Equipment project, indicating that the project and capital required to complete it should be prioritized.

A similar process including cross-departmental discussions occurred for each project. Results are shown in the above table, which includes projects below the materiality threshold. Subdivisions are included as they are a customer and shareholder priority, as housing concerns remain high across our communities. Computer Hardware, while not a large capital expense, is included because it is a backbone of the utility systems, enabling engineering, communications, finance and customer service. It supports system reliability, specifically in the LPDL Control room providing equipment to improve response time to outages and remote access to switchgear. Tools, Shop and Garage Equipment is included because it is a cross-functional support to many, if not all, projects that impact the efficiency, safety and reliability of the network. This is a direct impact on customer satisfaction.